NINETY-SEVENTH REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2007 THROUGH DECEMBER 31, 2007

NINETY-SEVENTH REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2007, through December 31, 2007

Edward S. Finley, Jr., Chairman

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

Howard N. Lee, Commissioner

William T. Culpepper, III, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Ms. Renné Vance
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, 2007

The Governor of North Carolina
Raleigh, North Carolina

Sir:

Pursuant to the provisions of Section 62-17(b) of the General Statutes of North Carolina, providing for the annual publication of the final decisions of the Utilities Commission on and after January 1, 2007, we hereby present for your consideration the report of the Commission's significant decisions for the 12-month period beginning January 1, 2007, and ending December 31, 2007.

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

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

Howard N. Lee, Commissioner

William T. Culpepper, III, Commissioner

Renné Vance, Chief Clerk

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Docket No. P-100, Sub 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Telecommunications Relay Service, North Carolina	) ORDER APPROVING A DECREASE IN) THE SURCHARGE, AUTHORIZING) BILL MESSAGE/INSERT) NOTIFICATION, AND APPROVING A) REVISION TO THE SURCHARGE) REMITTANCE FORM

BY THE COMMISSION: On October 12, 2007, the Commission received a petition from the Public Staff seeking, inter alia, to revise the monthly surcharge imposed on all qualified residential and business local exchange facilities (access lines)[1] in North Carolina to fund the Telecommunications Relay Service (TRS) and equipment distribution program for the deaf and hard of hearing. Under G.S. 62-157(b), the Commission requires local service providers to impose a monthly surcharge on qualified access lines to fund a relay service and an equipment distribution program.[2] The relay service and the equipment distribution program comprise Telecommunications Access North Carolina (TANC). The Commission, after giving notice and an opportunity to be heard to interested parties, sets the amount of the monthly surcharge based on the amount of funding necessary to implement and operate TANC, including a reasonable margin for reserve (reserve margin). The present monthly surcharge of $0.11 per access line went into effect in January 2002.[3]

In response to the Public Staff's petition, the Commission issued an Order Seeking Comments on the Surcharge, Approving a Reserve Margin, and Authorizing Review of Reserve Margin and Surcharge Biennially on October 30, 2007. In that order, the Commission approved a $9.6 million reserve margin and the regular biennial review of the reserve margin and the surcharge amount, starting in October 2009. It further requested interested parties to this docket to file comments regarding the proposed decrease in the surcharge no later than November 9, 2007.

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[1] Participants in the Subscriber Line Charge Waiver Program and the Link-up Carolina Program are exempt from imposition of the surcharge under G.S. 62-157(b).

[2] Under G.S. 62-157(a1)(5), a "local service provider" means a local exchange company, a competing local provider, or a telephone membership corporation.

[3] In the Matter of Telecommunications Relay Service, Relay North Carolina, Order Authorizing Increase in Surcharge, Docket No. P-100, Sub 110 (Nov. 13, 2001).

BACKGROUND

In 2004, Session Law 2003-341 amended G.S. 62-157 to require that a similar surcharge be imposed on wireless connections in North Carolina to provide additional funds for an expansion of TANC's services and to prepare for a potential increase in costs if the Federal Communications Commission (FCC) required the states' TRS funds to pay for intrastate video relay services (VRS) and internet protocol relay services (IP Relay). For these reasons, a wireless provider now collects the same monthly surcharge on wireless connections that is imposed on access lines and remits it to the Wireless 911 Board. The Wireless 911 Board then remits the surcharges to the appropriate Department of Health and Human Services (DHHS) fund. The "access line" fund and the "wireless connection" fund are separate, but both operate to fund TANC's services. The $0.11 monthly surcharge has been imposed on wireless connections in North Carolina since 2004.

PUBLIC STAFF'S PETITION

In its petition, the Public Staff also requested that the reserve margin be adjusted to reflect the increase in TANC's services and the potential increase in TANC's costs if the FCC required states to assume funding for VRS and IP Relay. The Public Staff proposed a $9.6 million reserve margin, which reflects $3 million to cover TANC's six months of operating costs, plus $1.8 million for TANC's relay contract expenses for six months and $4.8 million for six months of IP Relay and VRS costs.

According to the Public Staff, however, even with the increase in the reserve margin amount, incoming revenue continues to outpace TANC's expenses significantly. For that reason, the Public Staff proposed to reduce the monthly surcharge from $0.11 per access line to $0.09 per access line. If the Commission approves this reduction, it will result in the monthly wireless surcharge being similarly reduced from $0.11 per wireless connection to $0.09 per wireless connection. Based on the Public Staff's calculations, this reduction would bring the reserve margin to the approved $9.6 million in approximately 50 months, accounting for a ten percent increase in TANC's employee and service expenses. The Public Staff further recommended that the Commission begin a regular biennial review of the reserve margin and surcharge amount in October 2009.

COMMENTS

The Commission received timely filed comments from AT&T North Carolina and AT&T Mobility, jointly, and from the North Carolina Telecommunications Industry Association, Inc. (NCTIA). All comments supported the proposed decrease in the surcharge. Additionally, NCTIA indicated that it did not object to the decrease becoming effective immediately.

PUBLIC STAFF'S MOTION

In response to the comments in support of the proposed decrease, the Public Staff filed a Motion For An Order Approving A Decrease in the Surcharge, Authorizing Bill Message/Insert Notification, and Approving a Revision in the Surcharge Remittance Form and proposed order on November 28, 2007. In that motion, the Public Staff requested that the Commission approve the requested decrease in the monthly TRS surcharge effective January 1, 2008, which should allow the local service providers adequate time to reflect the decrease in their customers' bills. As it has done in past revisions to the surcharge amount, the Public Staff also requested the Commission to require that local service providers notify their customers of the surcharge decrease by a bill message/insert in their January bills as set forth in Appendix A.

The Public Staff additionally noted that confusion appears to exist regarding the portion of the monthly surcharge that the Commission has previously allowed local service providers to retain for collection, inquiry, and administrative expenses. Pursuant to the Commission's February 5, 1991 Order Setting Surcharge and Procedures for Implementation of System and November 13, 2001 Order Authorizing Increase of Surcharge, local service providers are allowed to retain $0.01 per access line of each monthly access line surcharge to cover their collection, inquiry and administrative expenses. The confusion arises, however, because Session Law 2003-341 amended G.S. 62-157 to allow wireless providers to retain only one percent (1%) of the total amount of surcharge collected each month to cover administrative costs.[1] Therefore, the amount retained for administrative costs differs between local service providers and wireless providers.

Moreover, the Public Staff reported that local service providers frequently rely upon billing companies to collect and remit the TRS surcharge. Some of these companies are located out of state and may not be as familiar with differences between the Commission's orders and the wireless connection provision of G.S. 62-157. Additionally, certain providers have underestimated the amount that they may retain each month for billing and collection expenses by multiplying the $0.01 times the surcharge amount, as opposed to the approved method of multiplying $0.01 times the number of access lines. Finally, at the time of the previous change in the surcharge, some companies revised their surcharge amount belatedly. Therefore, the Public Staff attached to its motion a revised remittance form for local service providers, or their billing companies, to use when collecting and remitting the monthly surcharge. The new remittance form clearly shows that local service providers should collect the $0.09 TRS surcharge per access line, per month, but remit only $0.08 per access line, per month, to the DHHS to fund TANC. They should retain $0.01 per access line, per month, for administrative costs.

Finally, the Public Staff also requested in its motion that the Commission approve the use of this remittance form and require the North Carolina Division of Services for the Deaf and Hard of Hearing to post it on its TANC website at http://dsdhh.dhhs.state.nc.us/division/tanc/tanc.html so that it can be downloaded by those companies that require its use. The Public Staff requested that the Commission direct local service providers to rely upon this remittance form only when remitting their TRS surcharges to DHHS, because all other forms for remitting the TRS access line surcharge are obsolete with this change in the surcharge. The Public Staff noted that the TRS remittance form for wireless providers, which differs from the TRS remittance form for local service providers, may be downloaded from the Wireless 911 Board's website.

WHEREUPON, the Commission reaches the following

[1] G.S. 62-157(i).

CONCLUSIONS

After careful consideration, the Commission concludes that it is appropriate to grant Public Staff's Motion.

Specifically, the Commission approves the reduction in the TRS surcharge from $.11 per access line per month to $.09 per access line per month, effective January 1, 2008. Also, the Commission approves the use of the revised remittance form attached hereto as Appendix B and requires the North Carolina Division of Services for the Deaf and Hard of Hearing to post it on its TANC website at http://dsdhh.dhhs.state.nc.us/division/tanc/tanc.html so that it can be downloaded by those companies that require its use. Furthermore, as recommended by the Public Staff, the Commission directs local service providers to rely upon this remittance form only when remitting their TRS surcharges to DHHS, because all other forms for remitting the TRS access line surcharge are obsolete with this change in the surcharge. The Public Staff noted that the TRS remittance form for wireless providers, which differs from the TRS remittance form for local service providers, may be downloaded from the Wireless 911 Board's website.

IT IS, THEREFORE, ORDERED as follows:

1. That the monthly TRS surcharge be decreased from $0.11 per access line to $0.09 per access line effective on January 1, 2008. The decrease should be reflected in customers' bills issued on or after January 1, 2008.

2. That the bill message/insert as set forth in Appendix A shall appear in customers' January bills, issued on or after January 1, 2008.

3. That local service providers be authorized to continue to retain $0.01 per access line, per month, of the TRS access line surcharge for collection, inquiry, and administrative expenses.

4. That the TRS surcharge remittance form attached hereto as Appendix B is approved for use by local service providers to remit their TRS access line surcharges to DHHS. With this change in the surcharge, all other TRS remittance forms are obsolete. Therefore, local service providers should rely exclusively upon this form in remitting their TRS access line surcharges to DHHS.

5. That the Division of Services for the Deaf and Hard of Hearing shall post the revised TRS surcharge remittance form, attached hereto as Appendix B, on the TANC website so as to make it available for downloading.

ISSUED BY ORDER OF THE COMMISSION
This the 13th day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh121307.01

APPENDIX A

NOTICE OF TELECOMMUNICATIONS RELAY SERVICE (TRS) SURCHARGE DECREASE

Effective with telephone bills issued on or after January 1, 2008, the Telecommunications Relay Service (TRS) surcharge is $0.09 per access line, per month. On December ____, 2007, the North Carolina Utilities Commission authorized a decrease in the monthly TRS surcharge amount from $0.11 to $0.09 to maintain adequate funding for Telecommunications Access North Carolina (TANC). TANC is a program within the North Carolina Department of Health and Human Services that enables persons with hearing, speech, and vision impairments to communicate with others by telephone.

APPENDIX B

NC DEPARTMENT OF HEALTH AND HUMAN SERVICES
DIVISION OF SERVICES FOR THE DEAF AND HARD OF HEARING
DHHS-RELAY NORTH CAROLINA

TELECOMMUNICATIONS RELAY SERVICE (TRS) SURCHARGE MONTHLY REPORT

SURCHARGES ARE TO BE COLLECTED IN ACCORDANCE WITH N.C.G.S. § 62-157 AND NORTH CAROLINA UTILITIES COMMISSION ORDERS IN DOCKET P-100, SUB 110, AND ARE TO BE REMITTED MONTHLY, ACCOMPANYING THIS REPORT, NO LATER THAN THE TWENTIETH (20^{TH}) OF THE FOLLOWING MONTH. CHECKS SHOULD BE MADE PAYABLE TO: **DHHS –RELAY NORTH CAROLINA** AND SHOULD BE MAILED AS FOLLOWS:

DHHS – Controller's Office A/R
2025 MAIL SERVICE CENTER
RALEIGH, NC 27699-2025

LEC/CLP/TMC: ____

Surcharges Collected/Billed for Calendar Month Ending: ______________________
Month / Day / Year

Number of Qualified Access Lines Billed During Calendar Month: __________

Number of Qualified Access Lines Collected During Calendar Month: __________

Surcharge Billed ($.09 per qualified access line): __________

Less: Billing and Collection Charge ($ .01 per access line collected): ________

Less: Uncollectibles/Adjustments for Prior Periods ________

Net Amount Remitted to DHHS: ____________

Remitted by (COMPANY, if different from above) ________________________________
(Please Print)

Authorized by ________________________________
(Please print):

Authorized Signature: ________________________________

Date: ________________________________

DOCKET NO. P - 100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Telecommunications Relay Service, North Carolina) ERRATA ORDER
)

BY THE CHAIRMAN: On December 13, 2007, the Commission issued its *Order Approving A Decrease In The Surcharge, Authorizing Bill Message/Insert Notification, and Approving A Revision To The Surcharge Remittance Form,* which included Appendix A – Notice of Telecommunications Relay Service (TRS) Surcharge Decrease which reflected a **blank date** for the issuance of the Order. This was an error. The second sentence of the notice set forth is Appendix A should read "On December 13, 2007, the North Carolina Utilities Commission authorized a decrease in the monthly TRS surcharge amount from $0.11 to $0.09 to maintain adequate funding for Telecommunications Access North Carolina (TANC)."

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

kh121407.01

DOCKET NO. P - 100, SUB 133f

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Lifeline and Link-up Service Pursuant to Section 254 of the Telecommunication Act of 1996	)))	ORDER CONCERNING TASK FORCE REPORT AND AUTHORIZING PILOT PROGRAM

BY THE COMMISSION: On July 16, 2007, the Lifeline/Linkup Task Force submitted its semi-annual report to the Commission, as requested in the Commission's *Order Requesting Further Study To Adopt Lifeline/Link-Up Program Expansion*, dated August 4, 2005.

The Task Force reported that, as of June 30, 2007, there were 121,228 households receiving Lifeline benefits. During the period January 1, 2007 through June 30, 2007, there were 3,022 households that received Link-Up discounts for the cost of connecting telephone service. In comparison, the December 31, 2006 reports filed by local providers reflected 126,408 Lifeline recipients. The Task Force also reported that the December 2006 reports showed that, from July 1, 2006 to December 31, 2006, there were 3,133 households that received Link-Up discounts. However, not all local telephone providers have filed their Lifeline/Link-Up statistics for the January 1, 2007 to June 30, 2007 period, so total numbers are tentative.

The Commission, in its previous Order, also instructed the Task Force to continue studying methods to streamline the application and eligibility processing for the Lifeline/Link-Up benefits. The Task Force has studied several ways to expand program participation since that time.

<u>As a first step to increase Lifeline/Link-Up participation, the Task Force recommended streamlining the enrollment process for Lifeline recipients who receive Food Stamps.</u> Under the current system, once a person is found eligible to receive Food and Nutrition Services (Food Stamps), Medicaid, Work First, Supplemental Security Income (SSI), Low Income Energy Assistance Program (LIHEAP) or Section 8 housing (hereafter collectively referred to as "qualifying benefit programs"), that person is automatically eligible to receive Lifeline/Link-Up benefits. However, before an individual can receive such benefits, county Department of Social Services (DSS) offices must receive the applications and verify eligibility for all of the qualifying benefits programs except Section 8 housing and SSI.

The Task Force recommended that the North Carolina Department of Health and Human Services (DHHS) data system, which maintains eligibility information on all recipients of Food Stamps, Medicaid, SSI, Work First and LIHEAP, be used to streamline the enrollment process. The Task Force has been working with DHHS to create a data file of individuals who have met the Food Stamps criteria. This file, once created, would be provided to the telephone companies monthly.

In the streamlined enrollment process, DHHS would scan the records of eligible Food Stamp recipients monthly to identify the telephone company providing local telephone service to each Food Stamp recipient. An electronic file would be created for each telephone company containing the names and telephone numbers of Food Stamp recipients receiving basic telephone service from that local exchange telephone company. The file would be mailed or sent by internet to the Lifeline/Link-Up coordinator of each local exchange telephone company. Each company would then match the DHHS eligibility file with its customer account records and identify persons eligible for the discount who are not receiving it. The telephone company would automatically grant the Lifeline discount to those persons starting with the next billing cycle.

Since the above procedure would eliminate steps one and two that presently are required to enroll Food Stamp recipients in Lifeline and certify their eligibility to their local telephone company, it should help to increase enrollment in the program.

The Task Force also noted that the Food Stamp application form has been revised to include information about Lifeline/Link-Up, obtain all necessary information about the applicant's local telephone company, and obtain a waiver to allow the benefits eligibility information to be shared with the applicant's telephone company. The major remaining step in implementing the new enrollment procedure is to add the Lifeline information to the Food Stamp computer data base. DHHS and the Task Force continue working towards that goal and remain optimistic that it can be met in 2007.

The Task Force also analyzed the Medicaid application process to determine if similar changes could be made to increase Lifeline enrollment. Here the outlook is more disappointing. The Task Force found that the Medicaid computer data base does not have the fields available for recording needed information. The Task Force concluded that it does not appear that similar changes allowing for the enrollment of Medicaid recipients will be possible in the near future.

With regard to Link-Up benefits for Food Stamp recipients, the enrollment procedure would remain similar to the present system. The reason is that those persons who do not have telephone service at the time of their Food Stamp application will have no telephone company to whom DHHS can send their Lifeline/Link-Up eligibility information. Therefore, those persons would be given a form stating their eligibility for Lifeline/Link-Up, and it would then be incumbent upon them to contact the local telephone company of their choice to establish service and become enrolled for Lifeline/Link-Up benefits.

The Task Force believed that the above described modifications in the Lifeline enrollment procedures for Food Stamp recipients will make the application and verification processes more efficient and increase participation in the program.

<u>As a second step to increase Lifeline/Link-Up participation, the Task Force studied the possibility of using a self-certification procedure for enrolling applicants in Lifeline/LinkUp and recommended that self-certification be tested in North Carolina.</u>

The Task Force noted that the present steps requiring the social services worker and applicant to complete a separate verification form and requiring the social services worker to send the completed form to the applicant's local telephone company reduce the efficiency of the eligibility process, while self-certification may be an avenue to improve its efficiency. Once fully implemented, self-certification would eliminate those two steps and, instead, the consumer could obtain a self-certification form from any number of sources, including the telephone company, DSS and other human service agencies. In order to reduce the possibility of fraud, the Task Force recommended that the self-certification form include a section in which the consumer would certify, under penalty of perjury, that he/she is a recipient of one or more qualifying benefits.

Verizon, Embarq, the smaller independent telephone companies and the telephone membership corporations have concerns about the additional administrative costs that self-certification could require, as well as the potential for fraud and the necessity for conducting eligibility reviews. However, the Task Force noted that AT&T uses self-certification in all of the other southern states it serves and that AT&T favors adopting such a system in North Carolina. AT&T is willing to try self-certification for a period of time to see how it works. Therefore, the Task Force recommended that the Commission approve a self-certification pilot program by AT&T for at least one year.

The Task Force also addressed the feasibility of adding two additional eligibility criteria, the National School Lunch Program (NSL) and an income test, to expand Lifeline/Link-Up participation, as earlier requested by the Commission.

NSL is administered jointly by the Department of Agriculture (USDA) and the North Carolina Department of Public Instruction (DPI). By federal law, a student's eligibility for free or reduced school meals is confidential information. DPI is authorized to share such information with other state agencies, such as Medicaid and the North Carolina Children's Health Insurance Program, for a few limited purposes. However, there is no authority for NSL data sharing between DPI, or the USDA, and DHHS.

The Task Force observed that, in some states, the state agency that manages the Lifeline/Link-Up data is also the agency that administers NSL, such as the Department of Social Services. Furthermore, other states have built the necessary information links by having a third-party administrator manage the Lifeline/Link-Up program and by giving the administrator the legal authority to receive all necessary information from the agencies that administer the qualifying benefit programs. North Carolina would need to make several significant changes in order to implement either of those models.

The Task Force pointed out that, to qualify for NSL, the applicant's household must be at or below 130% of the federal poverty guidelines. Furthermore, children in households that receive Food Stamps or Work First are automatically eligible for free school meals. The Task Force concluded that many of the households that would be added by including NSL as a Lifeline/Link-Up criteria are already covered under Food Stamps and Work First.

The Task Force has not conducted an exhaustive study, but there seem to be no definitive statistics showing that NSL eligibility criteria results in a substantial increase in Lifeline/Link-Up participation. The Task Force recommended not adopting the NSL program as an automatic eligibility criterion at this time.

The Task Force also studied the possibility of adding household income as an eligibility criterion. The Task Force stated that, in contradistinction to certification based on a person's eligibility for Foods Stamps, Medicaid and other qualifying benefits, separate income verification would be necessary if such a criterion were to be adopted. Furthermore, the FCC has recommended that this income verification function be the responsibility of the local telephone companies. However, the telephone companies do not have local offices in most areas, and the administrative costs of reviewing and verifying applications based on income eligibility could be substantial. The Task Force also believed it would not be practical to place this additional burden on the Food Stamp, Medicaid, Work First or SSI eligibility workers.

The Task Force also explored establishing an information link between DHHS and the North Carolina Department of Revenue (DOR) to enable DHHS to verify a Lifeline/Link-Up applicant's income and certify his/her eligibility to the telephone company. The Task Force stated that, similar to NSL information, the authority for sharing DOR individual taxpayer information with other agencies is very limited. The Task Force argued that these barriers and the cost of administering a Lifeline/Link-Up income criterion render that option infeasible at this time.

Lastly, the Task Force stated that it has been working with the North Carolina Families Accessing Services Through Technology (NC FAST) to ensure that Lifeline/Link-Up is among the public benefit programs offered under NC FAST. The Task Force stated that the target date for implementing NC FAST has been pushed back indefinitely because of funding and design considerations.

In concluding its report to the Commission, the Task Force reported that 200,000 Lifeline/Link-Up brochures were initially printed and that all but approximately 5,000 have been distributed to numerous agencies, telephone companies and organizations for distribution to residents. Also, a PDF version of the Lifeline/Link-Up brochure is available on the Commission's web site and on the DHHS wed site. Lastly, to ensure further outreach, AT&T has agreed to pay for 100 posters to be printed for placement in each of the DSS offices throughout the state.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the following actions should be taken to expand the availability of Lifeline/Link-Up benefits to qualified individuals: (1) authorize the streamlining of the Lifeline/Link-Up enrollment procedures for Food Stamps as recommended by the Task Force to efficiently inform recipients of Food Stamps of their eligibility for Lifeline and to certify their eligibility to their telephone company; (2) approve a pilot program by AT&T to allow self-certification of AT&T's customers for Lifeline/Link-Up; and (3) decline to adopt the NSL and household income eligibility criteria at this time for the reasons as generally stated by the Task Force.

The Commission commends the Task Force for its work thus far and believes that the Task Force should continue to work with the relevant human services agencies and local exchange telephone companies to further streamline the process of enrolling program participants. Based on the Task Force's report that the NC FAST project will be deferred indefinitely, the Commission continues to encourage the human services agencies and the local exchange telephone companies to discuss and analyze alternatives to expand the enrollment of Lifeline/Link-Up benefits to qualified recipients. In addition, the efficiency gains in the area of application processing should be beneficial to the agencies and telephone companies for the statistical reporting of Lifeline/Link-Up recipients.

The Commission is also supportive of the pilot study proposed by AT&T relating to self-certification to receive Lifeline/Link-Up benefits for qualifying recipients. We note the opposition expressed to this approach by Verizon, Embarq, the smaller independent telephone companies, and the telephone membership corporations to this approach, but we conclude that there is sufficient merit to the approach that AT&T should be allowed to conduct a twelve-month pilot study to gain information to evaluate whether the self-certification for Lifeline/Link-Up benefits approach should be expanded to include other local exchange telephone companies.

However, the Commission has one concern about the form AT&T wants to use. Certainly, prevention of fraud in a self-certification context is an important consideration, and the Commission appreciates the motivation behind the Task Force's recommendation that the self-certification form include a section requiring the consumer to certify, under penalty of perjury, that he/she is the recipient of one or more of the qualifying benefits. However, the Commission is unaware of any state statutory authority allowing it to subject a Lifeline recipient to prosecution for <u>perjury</u> for making a false, but unsworn,[1] statement in order to secure this benefit. State law does provide that if an applicant for benefits knowingly makes false statements to secure benefits to which he or she otherwise would not be entitled may subject the applicant to criminal prosecution. G.S. 14-100. Thus, the Commission believes that the self-certification form should be modified as follows:

> I certify that I am a current recipient of the above program(s) and that I am aware that knowingly providing false information to receive or to continue to receive the Lifeline/LinkUp benefit may subject me to criminal penalties. Further, I certify that I will notify AT&T North Carolina when I am no longer participating in at least one of the above designated program(s)...

Lastly, it appears that the NSL and household income criteria should not be adopted to expand automatic enrollment for Lifeline/Link-Up benefits. The Task Force explained that the lack of cohesion between NSL and household income with the other social benefits programs would prove too cumbersome to implement. Also, the use of these two additional criteria raised concerns as to degree of confidentiality for the applicants' data that would be required to receive Lifeline/Link-Up benefits. It also appears that there would be a significant degree of overlap of

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[1] Under North Carolina law, perjury is a defined as a false statement under oath, knowingly, willfully and designedly made, in a proceeding in a court of competent jurisdiction or concerning a matter where the affiant is required by law to be sworn as to some matter material to the issue or point in question. G.S. 4-209; <u>State v Smith</u>, 230 N.C. 198, 52 SE2d 348 (1949).

households that currently qualify for Lifeline/Link-Up benefits based on the present group social services programs if the NSL and household income criteria were added to qualify for Lifeline/Link-Up benefits.

IT IS, THEREFORE, ORDERED as follows:

1. That the streamlining of Lifeline enrollment procedures as recommended by the Task Force be authorized. The Task Force shall continue to study and report to the Commission regarding any modification that ensures further operational efficiencies in the enrollment procedure for Lifeline/Link-Up benefits.

2. That AT&T be allowed to implement a twelve-month pilot program for self-certification by qualified recipients to receive Lifeline/Link-Up benefits, provided that the self-certification form is modified as set forth above. AT&T is directed to submit to the Commission 30 days after the completion of the twelve-month pilot program its findings to include, but not be limited to the following information:

a. The raw number and percentage of applicants subscribing to Lifeline/LinkUp benefits through self-certification.

b. The raw number and percentage of applicants provided Lifeline/LinkUp benefits through self-certification and who later were determined to have knowingly provided false information in their application.

c. The identifiable additional cost incurred by AT&T associated with the administration and tracking of applicants receiving Lifeline/LinkUp benefits through self-certification and the methodology used to identify such costs.

d. AT&T's recommendation as to the continuation of self-certification.

3. That NSL and household income not be established as criterion to ensure automatic enrollment for Lifeline/Link-Up benefits at this time.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of September, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

je090407.02

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

DOCKET NO. E-2, SUB 903

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. for Authority to Adjust Its Electric Rates Pursuant to G.S. 62-133.2 and NCUC Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, August 7, 2007, at 9:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman Edward S. Finley, Jr., Presiding and Commissioners Sam J. Ervin, IV, Lorinzo L. Joyner, and William T. Culpepper, III

APPEARANCES:

For the Applicant:

Len S. Anthony, Deputy General Counsel – Regulatory Affairs, Progress Energy Service Company, Post Office Box 1551, Raleigh, North Carolina 27602-1551

Dwight Allen, Smith, Anderson, Blount, Dorsett, Mitchell & Jernigan LLP, Post Office Box 2611, Raleigh, North Carolina 27602-2611

For the Public Staff--North Carolina Utilities Commission:

Antoinette R. Wike, Chief Counsel, and Tab Hunter, Staff Attorney, Public Staff--North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Attorney General:

Len G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Utility Customers Association, Inc.:

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

For the Carolina Industrial Group for Fair Utility Rates II:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1351

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

BY THE COMMISSION: Pursuant to G.S. 62-133.2 and Commission Rule R8-55(e), Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. (PEC or Company), is required to file, at least 60 days prior to the first Tuesday in August of each year, an Application for a change in rates based solely on changes in the cost of fuel and the fuel component of purchased power. On June 8, 2007, PEC filed its Application, along with the testimony and exhibits of Company witnesses Dewey S. Roberts and Bruce P. Barkley. Pursuant to Ordering Paragraph No. 3 in the Commission's Order in Docket No. E-2, Sub 889, the Company requested an increment of 1.011¢/kWh (1.045¢/kWh including gross receipts tax) to the base fuel factor of 1.276¢/kWh approved in PEC's last general rate case, Docket No. E-2, Sub 537, and a recommended total base fuel factor of 2.287¢/kWh. The Company also requested an increment of 0.388¢/kWh (0.401¢/kWh including gross receipts tax) for the Experience Modification Factor (EMF) rider to collect $144.4 million of under-recovered fuel expense. The Company proposed that the EMF rider be in effect for a fixed 12-month period.

On June 11, 2007, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene, which the Commission granted on June 14, 2007.

On June 22, 2007, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which the Commission granted on June 27, 2007.

On July 18, 2007, the Attorney General filed a notice of intervention pursuant to G.S. 62-20.

The intervention of the Public Staff is noted pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On June 25, 2007, the Commission issued its Order Scheduling Hearing Dates, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice. The Commission scheduled the hearing for August 7, 2007, and required that intervenor testimony and exhibits, as well as petitions to intervene, be filed by July 25, 2007.

On July 25, 2007, the Public Staff filed the testimony of Michael C. Maness and the affidavits of Randy T. Edwards and Thomas S. Lam.

On August 1, 2007 PEC filed the rebuttal testimony of Bruce P. Barkley.

On August 6, 2007, PEC filed the affidavits of publication showing that public notice had been given as required by Rule R8-55(f) and the Commission's June 25, 2007 Order.

The docket came on for hearing, as ordered, on August 7, 2007. PEC presented the testimony of Dewey S. Roberts and Bruce P. Barkley. The Public Staff presented the testimony of Michael C. Maness. No other party presented a witness; however, with agreement from the parties, the Commission admitted the affidavits filed by Randy T. Edwards and Thomas S. Lam. The Commission requested the filing of proposed orders or briefs by September 4, 2007.

On September 4, 2007, PEC filed a proposed order. The Public Staff filed certain proposed findings of fact, evidence and conclusions, and ordering paragraphs. CUCA filed a brief and motion for reconsideration pursuant to G.S. 62-80 in this Docket and Docket No. E-2, Sub 889. On September 6, 2007, PEC filed a response in opposition to CUCA's motion for reconsideration.

Based upon the Company's verified Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission now makes the following:

FINDINGS OF FACT

1. Carolina Power & Light Company, db/a Progress Energy Carolinas, Inc., is duly organized as a public utility company under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. PEC is engaged in the business of generating, transmitting, and selling electric power to the public in North Carolina. PEC is lawfully before this Commission based upon its Application filed pursuant to G.S. 62-133.2 and Commission Rule R8-55.

2. The test period for purposes of this proceeding is the 12-month period ended March 31, 2007.

3. PEC's fuel procurement and power purchasing practices were reasonable and prudent during the test period.

4. The performance of PEC's base load plants during the test period was reasonable and prudent.

5. The test period North Carolina retail fuel expense underrecovery in this proceeding is $135,971,836. It is appropriate to increase this fuel expense underrecovery by $8,217,000 to reflect interest through March 31, 2007, related to the Settlement Agreements approved in Docket No. E-2, Subs 868 and 889.

6. It is reasonable to apply a 58% fuel ratio to the energy cost of purchases from power marketers and other sellers that are unable or unwilling to provide PEC with actual fuel costs.

7. The proper base fuel factor for PEC calculated pursuant to G.S. 62-133.2 is 2.288¢/kWh (2.364¢/kWh including gross receipts tax), which is an increment of 1.012¢/kWh (1.046¢/kWh including gross receipts tax) above the base fuel factor established in Docket No. E-2, Sub 537.

8. The appropriate EMF increment to use in this proceeding is 0.387¢/kWh (0.400¢/kWh including gross receipts tax) based on a total fuel cost underrecovery of $144,188,836.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2 sets out the verified, annualized information that each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for a historical 12-month period. Commission Rule R8-55(b) prescribes the twelve months ending March 31 as the test period for PEC. All pre-filed exhibits and direct testimony submitted by the Company in support of its Application utilized the twelve months ended March 31, 2007, as the test year for purposes of this proceeding. The Company made the standard adjustments to the test period data to reflect normalizations for weather, customer growth, generation mix, and Southeastern Power Administration (SEPA) and North Carolina Eastern Municipal Power Agency (NCEMPA) transactions.

The test period proposed by the Company was not challenged by any party, and the Commission concludes that the test period appropriate for use in this proceeding is the twelve months ended March 31, 2007.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 & 4

The evidence for these findings can be found in the Company's Application and the monthly fuel reports on file with the Commission, as well as the testimony of Company witnesses Barkley and Roberts and the affidavits of Public Staff witnesses Edwards and Lam.

Commission Rule R8-52(b) requires each utility to file a Fuel Procurement Practice Report at least once every ten years, as well as each time the utility's fuel procurement practices change. In its Application, the Company indicated that the procedures relevant to the Company's test period fuel procurement practices were filed in the Fuel Procurement Practices Report, which was updated in June 2005. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a). These reports were filed in Docket No. E-2, Sub 888 for calendar year 2006 and Docket No. E-2, Sub 898 for calendar year 2007.

Company witness Barkley described in detail the Company's coal and gas procurement practices. The Company relies on short-term and long-term simulation models to estimate the coal and gas requirements for the PEC generating plants. Using this information in conjunction with plant inventory levels and supply risks, a determination is made of the coal requirements at that time. Once this determination is made, coal suppliers are contacted and asked to submit bids to meet the coal requirements. Coal contracts are awarded based on an economic evaluation, supplier credit review, past performance, and coal specifications. Gas contracts are awarded using a similar process. During the test period, PEC purchased coal at an average price of $71.35 per ton and gas at $8.41/mmbtu, excluding fixed costs.

Witness Barkley further testified that PEC continuously evaluates the term and spot markets for fuel and purchased power in order to determine the appropriate portfolio of long term and spot purchases that ensures a reliable supply of electricity to customers at the lowest reasonable prices. Such evaluations include daily, weekly, and monthly solicitations and subscriptions to fuel pricing services and trade publications. Witness Barkley concluded that PEC prudently operated its generation resources and purchased power during the period under review in order to minimize its costs.

Witness Roberts testified that PEC mitigates the impact of increasing fuel costs by using a diverse mix of generating plant resources. The Company's efficient use of nuclear, fossil-fueled, and hydroelectric plants helps lessen the impacts of volatility in the price or supply of any one fuel source. This is illustrated by the fact that over 45% of PEC's generation during the test period was provided by nuclear plants at an average fuel cost of \$4.50/MWH—less than 20% of the cost of coal generation and less than 5% of the cost of natural gas generation.

Regarding power plant performance, witness Roberts testified that PEC uses two different measures to evaluate the performance of its generating facilities--the equivalent availability factor and the capacity factor. The equivalent availability factor is the percentage of a given period time that a facility is available to operate at full power if needed. It describes how well a facility was operated, even in cases where the unit was used in a load following application. Capacity factor measures the generation a facility actually produces against the amount of generation that theoretically could be produced in a given time period, based on the facility's maximum dependable capacity.

Regarding the operation of PEC's natural gas and coal fired plants, witness Roberts explained that PEC's combustion turbines averaged a 94.58% equivalent availability and a 3.77% capacity factor for the twelve-month period ending March 31, 2007. He testified that these performance indicators are consistent with combustion turbine generation's intended purpose. PEC's combustion turbine generation was almost always available for use, but operated minimally. PEC's intermediate Richmond County combined cycle unit had a 90.18% equivalent availability and a 28.21% capacity factor for the twelve-month period ending March 31, 2007. The Company's intermediate coal fired units had an average equivalent availability factor of 88.79% and a capacity factor of 59.37% for the twelve-month period ending March 31, 2007. Witness Roberts concluded that these performance indicators for the Company's intermediate units are indicative of good performance and management. Witness Roberts testified that PEC's fossil base load units had an average equivalent availability of 90.04% and a capacity factor of 69.53% for the twelve-month period ending March 31, 2007. Thus, he concluded that the fossil base load units were also well managed and operated.

With regard to the operation of PEC's nuclear generation plants, witness Roberts explained that, for the twelve-month period ending March 31, 2007, the Company's nuclear generation system achieved a net capacity factor of 91.84%. This capacity factor includes nuclear plant refueling outages. In contrast, the North American Electric Reliability Council's (NERC) five-year average capacity factor for 2001-2005, appropriately weighted for the size and type of each plant in PEC's nuclear system, was 87.51%. The Company's nuclear system incurred a 3.2% forced outage rate during the twelve-month period ending March 31, 2007, compared to the industry average of 4.49% for similar size nuclear generators. Witness Roberts concluded that these performance indicators reflect good nuclear performance and management for the review period.

Witness Roberts explained that Commission Rule R8-55 provides that a utility shall enjoy a rebuttable presumption of prudent operation of its nuclear facilities if it achieves a system average nuclear capacity factor during the test period that is (a) at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the latest NERC Equipment Availability Report, appropriately weighted for size and type of plant, or (b) an average systemwide nuclear capacity factor, based upon a two-year simple average of the systemwide capacity factors actually experienced in the test year and the preceding year, that is at least equal to the national average capacity factor for nuclear production facilities based on the most recent 5-year period available as reflected in the most recent NERC Equipment Availability Report, appropriately weighted for size and type of plant. Witness Roberts testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55(i). Public Staff witness Lam verified the Company's test year average capacity factor calculation.

Regarding power purchases to displace Company owned generation, witness Roberts testified that the Company is constantly reviewing power markets for purchase opportunities. He explained that PEC purchases power when there is reliable power available that is less expensive than the marginal cost of the Company's available resources. This review of the power markets is done on an hourly, daily, weekly, and monthly basis. Also, with regard to long term resource planning, PEC always evaluates purchased power opportunities against self-build options.

No other party offered any evidence regarding PEC's fuel procurement, power purchases, or base load performance during the test period. Thus, the Commission finds and concludes that PEC's fuel procurement procedures and power purchasing practices and the operation of the Company's base load plants were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5-8

The evidence supporting these findings can be found in the testimony and exhibits of Company witnesses Barkley and Roberts, the affidavits of Public Staff witnesses Edwards and Lam and the testimony of Public Staff witness Maness.

In Barkley Exhibit No. 5, the Company calculated a fuel factor of 2.339¢/kWh based on normalized capacity factors for its nuclear units in accordance with Commission Rule R8-55(c)(1), by using the five-year NERC Equipment Availability Report 2001-2005 average for boiling water reactors (BWRs) and pressurized water reactors (PWRs). The workpapers included in Barkley Exhibit No. 9 show kWh normalization for customer growth and weather at both meter and generation levels performed in a manner consistent with that used in past cases. Normalization adjustments were also made for SEPA deliveries and hydro generation. The unit prices used for coal, nuclear, internal combustion turbines, purchases, and sales were also calculated in a manner consistent with that used in past cases. The NERC five-year capacity factors for Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 86.07%, and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at

89.18%. The Company's NERC normalized calculations resulted in a system nuclear capacity factor of 87.51% using this data.

In Barkley Exhibit No. 5A, the Company calculated a fuel factor of 2.358¢/kWh based on forecasted nuclear generation performance, kWh sales, and fuel cost. After reviewing the Company's Application, Public Staff witness Lam concluded that this factor was reasonable. The computation of the 2.358¢/kWh fuel factor is summarized below:

Generation Type	MWhs	Fuel Cost
Nuclear	28,664,829	$136,517,255
Purchases - Cogeneration	653,451	25,048,499
Purchases - AEP Rockport	2,015,402	37,921,107
Purchases - Broad River	546,978	59,638,816
Purchases - SEPA	182,228	0
Purchases - Other	208,963	8,207,774
Hydro	638,699	0
Coal	32,391,138	993,046,230
IC & CC	1,975,708	221,765,888
Sales	(2,062,350)	(60,079,732)
Total Adjusted	65,215,046	$1,422,065,837
Less NCEMPA:		
PA Nuclear	3,856,189	19,247,300
PA Buy-Back & Surplus	(109,776)	(1,364,300)
PA Coal	1,359,471	43,292,400
System Projected Fuel Expense		1,360,890,437
Projected kWh meter sales		57,703,629,000
Projected Fuel Factor (¢/kWh)		2.358

No other party presented any evidence regarding PEC's forecasted fuel cost during the period the rate set in this proceeding would be in effect, nor did any other party challenge PEC's forecasted fuel costs or fuel factor. Therefore, the Commission concludes that, in the absence of the Settlement Agreement approved in Docket No. E-2, Sub 889, PEC would be entitled to a fuel factor of 2.358¢/kWh (2.394¢/kWh including gross receipts tax) pursuant to the provisions of G.S. 62-133.2.

However, witness Barkley did not recommend the adoption of a factor of 2.339¢/kWh or 2.358¢/kWh. Instead, he recommended the establishment of a fuel factor of 2.287¢/kWh based on the Settlement Agreement approved by the Commission in PEC's 2006 fuel case proceeding, Docket No. E-2, Sub 889. Witness Barkley explained that Ordering Paragraph No. 3 of the Commission's September 25, 2006 Order issued in Docket No. E-2, Sub 889 provides:

> That effective for service rendered on and after October 1, 2007, an EMF shall be derived based upon PEC's fuel cost under-recovery for the test year ending March 31, 2007, including any approved interest, and the prospective component of the fuel factor will be equal to 2.675¢/kWh less the derived EMF.

Witness Barkley calculated and requested approval of an EMF of 0.388¢/kWh. Therefore, the base fuel factor to be established in this proceeding pursuant to the Settlement Agreement, as recommended by PEC, is 2.287¢/kWh.

Public Staff witness Lam also supported the derivation of a base fuel factor to be established in this proceeding based upon the Settlement Agreement approved by the Commission in Docket No. E-2, Sub 889. Since the EMF recommended by the Public Staff equaled .387¢/kWh, witness Lam recommended a corresponding base fuel factor of 2.288¢/kWh.

As noted above, PEC witness Barkley also calculated and recommended that the Commission approve and establish an EMF increment equal to 0.388¢/kWh in this proceeding in order to allow PEC to collect $144,378,411 of under-recovered fuel expense. Witness Barkley testified that the total under-recovered fuel expense of $144,378,411 consisted of three components. The first component was the test period under-recovery of $135,824,352 using the base fuel factors approved by the Commission in Docket No. E-2, Sub 868, PEC's 2005 fuel proceeding, and Docket No. E-2, Sub 889, PEC's 2006 fuel proceeding, which were in effect for billing purposes during the test year in this proceeding. The test period under-recovery amount of $135,824,352 also included the use of a 50% fuel to energy cost ratio to determine the fuel cost of certain power purchases made by PEC from power marketers and other sellers who did not provide PEC with the actual fuel costs of such purchases. The second component consisted of an adjustment of $147,484 added to the test period under-recovered fuel expense as a result of increasing the 50% fuel to energy cost ratio for certain power purchases to a 58% ratio for the reasons described below. The third component was $8,406,575 of interest calculated by witness Barkley consistent with his interpretation of the Settlement Agreements and the Commission Orders in Docket No. E-2, Sub 868 and Docket No. E-2, Sub 889, which authorized the accrual of interest on certain under-recovered fuel costs. Witness Barkley calculated the requested EMF increment of 0.388¢/kWh (0.401¢/kWh) by dividing the total under-recovered fuel cost of $144,378,411 by the projected North Carolina retail sales of 37,240,057,920 kWhs.

Public Staff witness Edwards reviewed the EMF increment rate rider requested by PEC and made only one adjustment. Based upon the recommendation of Public Staff witness Maness that the amount of interest included by PEC in its total under-recovered fuel costs should be reduced by $190,000, witness Edwards testified that PEC's EMF increment rider should be based upon a total fuel cost under-recovery of $144,188,411 divided by the projected North Carolina retail sales of 37,240,057,920 kWhs. Therefore, witness Edwards recommended an EMF increment rider equal to 0.387¢/kWh. This adjustment was opposed by PEC and is addressed elsewhere in this Order.

Concerning the 58% fuel to energy cost ratio, Public Staff Edwards explained that, during the test year utilized for purposes of this proceeding, PEC purchased power from a number of power marketers, as well as from other suppliers who did not provide PEC with the actual fuel costs associated with those purchases. In order to determine the percentage of these power purchase costs properly categorized as fuel costs, the Public Staff recommended the adoption of the approach for addressing this issue used in prior cases.

For purposes of calculating a percentage to be applied in fuel proceedings held in 2007, the Public Staff performed a review of the aggregate fuel component of off-system sales for Duke Energy Carolinas, LLC (Duke) and PEC for the twelve months ended December 31, 2006. These sales are set forth in each of the utilities' Monthly Fuel Reports. Unlike in past years, the off-system sales for Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), were not utilized in this review for purposes of calculating the fuel-to-energy percentage. The rationale for excluding DNCP from this analysis was two-fold. First, evaluation of the data indicated that there were only two DNCP off-system sale transactions that were eligible for inclusion in determining the appropriate fuel-to-energy percentage. One of those two transactions appeared to utilize a "proxy percentage" to determine the fuel component of total energy costs, rather than actual fuel costs. The other transaction had an immaterial impact on the analysis. Second, neither of the transactions recorded megawatt hours for the associated off-system sales. Thus, the inclusion of neither of these transactions would provide meaningful data for use in the analysis. Therefore, the Public Staff considered it reasonable to exclude these transactions from the determination of the fuel-to-energy percentage for purposes of this proceeding.

Witness Edwards explained that despite the removal of DNCP transactions, overall, this analysis was similar to that performed by the Public Staff for the 1997 Stipulation addressing this issue (which was applicable to the utilities' 1997 and 1998 fuel proceedings), and the similar 1999 Stipulation filed in Docket No. E-2, Sub 748 (applicable to the 1999, 2000, and 2001 fuel cost proceedings). Similar analyses were performed for the fuel proceedings held in 2002, 2003, 2004, 2005, and again in 2006. The methodology used for each of the abovementioned Stipulations and subsequent fuel proceedings has been accepted by the Commission as reasonable in each fuel case since the beginning of 1997.

G.S. 62-133.2 requires that purchased power-related costs recovered through fuel proceedings consist of only the fuel cost component of those purchases. However, in its Order in Duke's 1996 fuel proceeding, the Commission stated that whether a proxy for actual fuel costs associated with these types of purchases would be acceptable in a future fuel proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available." Public Staff witness Edwards stated that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the proxy fuel cost as described above. Because the sales made by marketers and other suppliers utilize the same types of generation resources that the utilities use to make their sales, the Public Staff believes that it is reasonable to assume for purposes of this proceeding that the fuel-to-energy percentage inherent in the purchases made by the utilities is similar to the percentage exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel percentage was derived from the Monthly Fuel Reports filed with the Commission and, in the opinion of the Public Staff, that information is reasonably reliable. Finally, the Public Staff stated it is unaware of any alternative information concerning the fuel cost component of marketers' sales made to utilities that is currently available for use by the Commission.

Therefore, the Public Staff believes that the methodology used in past Stipulations and in the analysis proposed for use in this proceeding meets the criteria set forth in the 1996 Duke Order.

As part of its current review, the Public Staff analyzed the relevant off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 56.61% to 60.53%, as set forth on Edwards Exhibit I. After evaluating all of the data and calculations, the Public Staff concludes that the off-system sales fuel ratio should be 58%. No other party challenged this recommendation or offered any alternative proposal.

The Commission notes that the fuel cost associated with marketer purchases is an important part of the Company's overall fuel cost. The use of a ratio to determine marketer fuel cost evolved with the emergence of an active wholesale bulk power market in 1996, which prompted this Commission to address the issue in the 1996 Duke Power Company fuel case. In its Order in that proceeding, the Commission stated, "When faced with a utility's reliance upon some such form of proof [i.e., a reasonable and reliable proxy] in a future fuel adjustment proceeding, the considerations will be whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available." Recognizing that an active wholesale bulk power market continues to evolve and applying this standard to the evidence presented herein, the Commission concludes, as it has in past proceedings, that the methodology recommended and used by the Public Staff to determine the fuel cost component of purchases from power marketers and other suppliers (1) satisfies the requirements set forth in the 1996 Duke fuel case order and (2) is reasonable and will be accepted for purposes of this proceeding. The Commission approved the use of the 58% ratio in the most recent Duke Power fuel proceeding, Docket No. E-7, Sub 825. The Commission also concludes that the use of a 58% ratio in this proceeding as recommended by Public Staff witness Edwards is reasonable and should be adopted for purposes of the proceeding.

As noted above, the only contested issue among the witnesses was the proper methodology for calculating the appropriate amount of interest on the under-recovery of PEC's fuel costs that occurred as a result of a Settlement Agreement approved by the Commission in Docket No. E-2, Sub 868, PEC's 2005 fuel charge adjustment proceeding. PEC witness Barkley and Public Staff witness Maness agreed that it was appropriate to include interest in the determination of the EMF to be approved for PEC in this proceeding to enable PEC to begin collecting the accrued interest. However, PEC witness Barkley concluded that the appropriate amount of interest was approximately $8,407,000, while Public Staff witness Maness determined that the appropriate amount of interest was equal to $8,217,000.

In his testimony, Public Staff witness Maness pointed out that the Commission approved a Settlement Agreement in Docket No. E-2, Sub 868 (the Sub 868 Settlement Agreement) that provided for a lower base fuel factor than the base fuel justified by the evidence in that case. This lower fuel factor was placed into effect and was billed by PEC for service rendered between October 1, 2005, and September 30, 2006. The Sub 868 Agreement also included the following provision:

> PEC shall be allowed to charge and collect interest at the rate of 6%, compounded annually, on under-recovery of fuel costs that occurs during the time period October 1, 2005, through September 30, 2006, as a result of having adjusted the base fuel factor by 0.499 cents per kWh instead of 0.880 cents per kWh excluding gross receipts tax, as proposed in its Application, until all such costs have been recovered.

Witness Maness noted that the Commission approved the Sub 868 Settlement Agreement and concluded that PEC would be allowed to collect the interest accrued pursuant to this Agreement as part of its EMF in future fuel proceedings, as actual amounts became known.

In Docket No. E-2, Sub 889, PEC's next fuel proceeding in 2006, witness Maness stated that the Commission approved another Settlement Agreement (the Sub 889 Settlement Agreement) which provided for a total fuel factor (including the EMF) for the period October 1, 2006, through September 30, 2007, which was lower than the total fuel factor justified by the evidence in that proceeding. The Sub 889 Agreement included the following provision:

> PEC shall be allowed to charge and collect 6% interest on an amount equal to the under-recovery resulting from PEC agreeing to a total fuel factor of 2.55 cents per kWh in the 2006 case rather than a total fuel factor of 2.856 cents per kWh (exclusive of gross receipts tax) until all such costs have been recovered.

Witness Maness testified that PEC had included interest accrued from October 1, 2005, through March 31, 2007, related to the Sub 868 and Sub 889 Settlement Agreements, in the EMF which PEC proposes to put into effect on October 1, 2007. Witness Maness agreed that PEC should begin collecting the interest which had already accrued through March 31, 2007, in the EMF approved in this proceeding; however, he testified that he had calculated a different amount on which interest should be computed than PEC.

PEC witness Barkley explained in his rebuttal testimony that PEC will collect the under-collections and interest associated with the Sub 868 Settlement Agreement over two annual billing periods. He testified that one portion will be recovered over the billing period beginning October 1, 2006, and the remainder will be collected during the period that will begin October 1, 2007. He also explained that the disagreement over the appropriate amount of interest pertains strictly to the timing of the repayment of the interest associated with the Sub 868 Settlement Agreement, which began on October 1, 2006, since the collection of the shortfall associated with the Sub 889 Settlement Agreement will not begin until October 1, 2007.

PEC witness Barkley and Public Staff witness Maness each used a different methodology to calculate their recommended interest amounts. The methodology used by Public Staff witness Maness is set forth in Maness Exhibit I, Schedule 2. The methodology used by PEC witness Barkley is set forth in Barkley Rebuttal Exhibit 2.

Public Staff witness Maness testified that his method of calculating interest consisted of comparing two series of cash flows: (1) the incurrence and recovery of fuel costs pursuant to the Sub 868 and Sub 889 Settlement Agreements and (2) the incurrence and recovery of fuel costs that would have occurred in the absence of the Settlement Agreements. He stated that, by basing the interest calculation on the difference between cash flows experienced pursuant to the Agreements and those that would have been experienced had the Settlement Agreements not been approved, he had captured the impact of the Settlement Agreements on the Company's cash flows.

According to witness Maness, both he and the Company increased the principal amount on which interest is based from zero to approximately $60 million for the first six months covered by the Sub 868 Settlement Agreement (October 2005 through March 2006), which reflected the difference between the net cash flow that actually occurred during that period as a result of the Settlement Agreement and the net cash flow that would have occurred in the absence of the Settlement Agreement. However, for the first six months of the period during which the under-recovery resulting from the Sub 868 Settlement Agreement began to be collected through the EMF approved in Sub 889 (October 2006 through March 2007), he reduced the principal amount by approximately $27 million (about six months' worth of the initial principal buildup of $60 million) for purposes of the interest calculation, while the Company reduced the principal amount by approximately $12 million. Witness Maness explained that he used the same approach in calculating the buildup of the principal during the collection period as he did in calculating the reduction of the principal during the true-up period, i.e., a comparison of cash flows with and without the Agreement. On the other hand, witness Maness testified that the Company departed from this approach in the second part of its calculation and, instead of comparing cash flows with and without the Settlement Agreement, reduced the $60 million principal by only a pro rata portion of the cash flows that occurred with the Settlement Agreement.

Witness Maness stated that his method is preferable to that used by the Company for several reasons, including the fact that his recommended calculation was based on a consistent, direct examination of the two alternative series of cash flows, and it captured the actual differences in those cash flows for purposes of the calculation of interest, while the Company's method essentially switched from using the differences in the cash flows under each scenario to using the cash flows related only to the with-Settlement Agreement scenario. He stated that the Company's approach departed from measurement of the actual timing of cash flows that have occurred due to the Agreements, and could not provide an accurate calculation of interest.

PEC witness Barkley testified in rebuttal that under-recoveries and interest are recovered through EMFs established by Commission Rule R8-55(c)(2). He further testified that the Public Staff's attempt to "link the monthly collection of amounts through an EMF to the time period in which the under-recovery arose is not supported by Rule R8-55 or the Commission's normal operating procedures for electric utility fuel reviews." According to witness Barkley, witness Maness assumed that the EMF approved in Sub 889 would result in PEC recovering $60 million of the $140 million difference between the revenues that would have been collected under the 2.156¢/kWh fuel factor and the revenues that were actually collected under the 1.775¢/kWh factor, witness Maness' "theory" being that the difference between the fuel factors applied to sales from October 1, 2005, through March 31, 2006, is $60 million. Witness Barkley stated that this is not correct because actual under-recoveries fluctuate monthly and the portion of the Sub 889 EMF associated with the Sub 868 under-recoveries does not require a "hypothetical" calculation. Rather, witness Barkley believed that the amount of the Sub 868 under-recovery collected through the Sub 889 EMF should be taken directly from Barkley Rebuttal Exhibit No. 1 (which is itself derived from Barkley Exhibit No. 6 in Sub 889), which shows an under-recovery of fuel costs related to Sub 868 during the period October 1, 2005, through March 31, 2006, of approximately $26 million. Witness Barkley stated that Barkley Exhibit I makes it clear that "only $26 million of the $178 million being recovered in the Sub 889 EMF pertains to Sub 868."

Witness Barkley also presented a table to compare the positions of PEC and the Public Staff regarding the amount of the Sub 889 EMF associated with the Sub 868 under-recovery to illustrate why, in his view, PEC has correctly calculated interest. According to witness Barkley, this table shows that the difference between the PEC and Public Staff positions ($34 million) is the result of subtracting the $26 million supported by Barkley Rebuttal Exhibit No. 1 from the $60 million calculated by witness Maness. Witness Barkley stated that, since the $178 million undercollection approved by the Commission for the EMF approved in Sub 889 remains the same under the two positions, it is logical to assume that the $34 million undercollection added to the Sub 868 amount by witness Maness would be deducted from the Sub 851 amount, and maintained that it is inappropriate to adjust that $139 million amount downward since it was approved in Sub 889 as shown on Barkley Rebuttal Exhibit 1. Witness Barkley then stated that witness Maness' adjustment, which he called a "hypothetical reconfiguration of the EMF," has the effect of accelerating the repayment of PEC's under-recovery in Sub 868 and represents the transfer of $34 million collected in a non-interest bearing docket (Sub 851) to reduce an obligation owed to PEC in an interest bearing docket (Sub 868).

In considering this issue, the Commission notes at the outset that the Settlement Agreements were entered and submitted for approval by both PEC and the Public Staff in Docket Nos. E-2, Sub 868 and Sub 889. Having entered and submitted Settlement Agreements, these parties now disagree as to how the interest provisions of those Settlement Agreements should be implemented. The Commission is now placed in the position of deciding this issue, which ultimately depends upon the appropriate construction to be placed upon the relevant language in the Sub 868 Settlement Agreement as approved by the Commission. Although the Commission very much appreciates PEC's decision to mitigate the impact of recent increases in fuel costs upon customers through the mechanisms incorporated into these Settlement Agreements, the issue which the Commission must confront in this proceeding is the manner in which the relevant provisions of the Sub 868 Settlement Agreement should be construed.

The Commission has carefully considered the testimony and exhibit of Public Staff witness Maness and the rebuttal testimony and exhibits of Company witness Barkley in its evaluation of this complex issue. After carefully examining the testimony of the two witnesses, it is clear that their calculations attempt to make two different determinations. On the one hand, the calculation presented by Company witness Barkley attempts to measure the difference between fuel-related revenues and fuel expenses during the relevant recovery period. On the other hand, the calculation presented by Public Staff witness Maness attempts to determine the difference in fuel-related revenues that would have been recouped had the Commission adjusted the base fuel factor by 0.499¢/kWh instead of by the 0.880¢/kWh figure that the record would have supported in the absence of the Sub 868 Settlement Agreement. In other words, the Commission concludes that both the calculation sponsored by PEC witness Barkley and Public Staff witness Maness simply attempt to measure different things. As a result, the ultimate issue before the Commission in this proceeding is whether, under the Sub 868 Settlement Agreement as approved in the Commission's Order in that proceeding, interest should be calculated based on a principal amount consisting of the total fuel cost under-recovery that resulted from the Commission's decision in that proceeding or the difference between the fuel adjustment that would have been approved in the absence of the Sub 868 Settlement Agreement and the fuel factor adjustment that resulted from approval of that Settlement Agreement.

The appropriate manner in which to resolve this issue requires a determination of which proposed interest calculation methodology is more consistent with the language of the Sub 868 Settlement Agreement. Paragraph No. 3 of this Settlement Agreement is the pertinent provision. It reads as follows:

> PEC shall be allowed to charge and collect interest at the rate of 6%, compounded annually, on under recovery of fuel costs that occurs during the time period October 1, 2005, through September 30, 2006, as a result of having adjusted the base fuel factor by 0.499 cents per kWh instead of 0.880 cents per kWh excluding gross receipts tax, as proposed in its Application, until all such costs have been recovered.

The appropriate reading of this provision is that the "under recovery of fuel costs" on which interest is to be calculated is the under-recovery specifically caused by the 0.381¢/kWh difference between (1) the base fuel factor increment that was agreed upon in the Settlement Agreement and ultimately approved by the Commission (0.499¢/kWh) and (2) the base fuel factor increment that would have been approved by the Commission in the absence of the Settlement Agreement (0.880¢/kWh). The Commission reaches this conclusion based on the literal language of the relevant provision of the Sub 868 Settlement Agreement, which indicates that the amount upon which the interest calculation should be based is the under-recovery that "results" from the decision to adjust PEC's base fuel factor "by 0.499 cents per kWh instead of 0.880 cents per kWh . . . ." In other words, the under-recovery that the relevant Settlement Agreement provision addresses is caused by a difference in fuel revenues, i.e., the difference between revenues resulting from charging one fuel factor (the one approved pursuant to the Settlement) instead of another (the one that would have been approved absent the Settlement). It is not the same under-recovery as that measured by the difference between fuel revenues and fuel costs for the purpose of calculating the EMF pursuant to Commission Rule R8-55(c)(2). Adoption of a reading that treats the relevant under-recovery as that measured by the difference between fuel-related revenues and fuel costs would also make the reference to a 0.880¢/kWh fuel adjustment contained in the relevant provision of the Sub 868 Settlement Agreement superfluous, since that figure would have no impact on the interest calculation in the event that the Commission were to determine that the interest calculation should be based on the difference between fuel-related revenues and fuel costs.

The Commission's interpretation of the interest provisions of the Sub 868 Settlement Agreement is also consistent with the provisions of the Commission's decision in Docket No. E-2, Sub 889. In that proceeding, the Settlement Agreement approved by the Commission provided, in pertinent part, that:

> PEC shall be allowed to charge and collect 6% interest on an amount equal to the under-recovery resulting from PEC agreeing to a total fuel factor of 2.550 cents per kWh in the 2006 case rather than a total factor of 2.856 cents per kWh (exclusive of gross receipts tax) until all such costs have been recovered.

In its Order approving the Sub 889 Settlement Agreement, the Commission stated that this language allowed PEC "to accrue 6% interest on an amount equal to the difference between 2.550¢/kWh and 2.856 ¢/kWh applied to service rendered between October 1, 2006 and September 30, 2007 . . . ." As a result, the Commission's language with respect to the interest issue in its Order in Docket No. E-2, Sub 889 focuses on the difference between the fuel-related revenues that PEC actually received and the fuel-related revenues that PEC would have received had the Commission established a fuel factor at the level supported by the record evidence instead of approving the Settlement Agreement. It is unlikely that the Commission would have intended to approve different methods for calculating allowable interest under the Sub 868 and Sub 889 Settlement Agreements. Thus, the construction of the Sub 889 Settlement Agreement adopted in the Commission's Order in Docket No. E-2, Sub 889, while not conclusive, provides strong support for our conclusion that the approach on which the Public Staff's calculation of the appropriate interest amount is allegedly based is more consistent with the Sub 868 Settlement Agreement than that proposed by PEC.

Furthermore, the construction of the Sub 868 Settlement Agreement adopted by the Commission in this proceeding is fully consistent with the underlying justification for allowing the accumulation of interest on a part of the Sub 868 under-recovery. The Commission's Order in Docket No. E-2, Sub 868 approved the accrual of interest "because PEC is foregoing revenues that it is otherwise entitled to collect in rates during the upcoming year" and because taking that action "is necessary . . . in order to make PEC whole." In other words, the interest provisions of the Sub 868 Settlement Agreement were intended to put PEC in the same position that it would have occupied had the fuel adjustment approved in that proceeding been established in accordance with the record evidence.

According to Commission Rule R8-55, interest is not generally allowed to be accumulated on fuel cost under-recoveries. As a result, had the fuel adjustment approved for PEC in Docket No. E-2, Sub 868 been set at 0.880¢/kWh rather than 0.499 ¢/kWh, the Company would not have been allowed to accumulate interest on the amount of any resulting under-recovery. In this instance, however, PEC agreed to a smaller fuel adjustment than was supported by the record evidence, a result which would inevitably produce a larger under-recovery than would have existed had the Company's level of fuel expense been set at the higher level. Allowing interest on the amount of the additional or incremental under-recovery resulting from the use of a 0.499¢/kWh fuel adjustment as compared to a 0.880¢/kWh fuel adjustment places PEC in the same position it would have occupied had the fuel component of its rates been established at a level consistent with that supported by the record evidence (assuming that the stipulated interest rate is appropriate, an issue about which there was no apparent disagreement among the parties). Computing interest on the basis of the difference between the amount of fuel-related revenues and fuel costs resulting from the fuel adjustment ultimately approved by the Commission does not produce a similarly consistent result. Thus, construing the Sub 868 Settlement Agreement in the manner determined to be appropriate by the Commission is consistent with the entire reason that PEC was allowed to recover interest under that agreement.

As a result, because the calculation of the principal amount upon which the interest resulting from the Sub 868 Settlement Agreement is appropriately based on differences in fuel revenues caused by the differences in base fuel factors resulting from the Settlement Agreement, the Commission concludes that it is necessary to compare the fuel revenues generated by the fuel adjustment that was actually approved in Docket No. E-2, Sub 868 and the fuel factor that would have been approved if the Settlement had not occurred. Put another way, under the appropriate construction of the Sub 868 Settlement Agreement, it is the difference between the use of these two factors that determines the impact of the Settlement on the interest calculation. As a result, the Commission must now turn to the calculations proposed by the Company and the Public Staff to determine which one, if either, is consistent with the method that the Commission has determined to be appropriate. In view of the fact that the calculation proposed by the Company is not based on the construction of the Settlement Agreement that the Commission has found to be appropriate, the Commission cannot base its decision with respect to the interest calculation issue on the approach recommended by PEC witness Barkley. On the other hand, after careful review, the Commission concludes that the calculation recommended by Public Staff witness Maness follows the appropriate path. This can be determined not only through a review of witness Maness' testimony, but also through a close review of his calculation, which is set forth on Maness Exhibit I, Schedule 2.

An examination of Maness Exhibit I, Schedule 2, reveals that it is divided into three sections. The first section, page 1, is entitled "With Settlement." Through examination of the line and row headings, as well as the footnotes to the Schedule, it is clear that this section calculates the net cash flow related to base fuel factor revenues, fuel costs, and the EMF for the period October 2005 through March 2007. The second section, page 2, is entitled "Without Settlement." This section calculates the net cash flow assuming that the Sub 868 and 889 base fuel factors, as well as the EMF, were set at the amounts that would have been approved by the Commission absent the Settlement Agreements in both those cases. The third section, page 3, entitled "Interest Calculation," takes the differences between the monthly cash flows calculated in sections one and two and calculates interest on them. The Commission notes that the only external input that differs between sections one and two is the fuel revenue factor; thus, the difference between the cash flow results in each of the two sections is driven entirely by differences in fuel revenue, not fuel cost. The Commission also notes that the base fuel revenue factors used in each section are, respectively, the factors that were approved as a result of the Settlement Agreements and those that would have been approved absent the Settlements.

The Commission has carefully followed how witness Maness calculated the EMFs used in his Exhibit I, Schedule 2 – the EMF assuming the existence of the Sub 868 Settlement, set forth on page 1, column (g), and the EMF assuming no Sub 868 Settlement, set forth on page 2, column (o). Footnote 6 on page 1 and footnote 11 on page 2 indicate that in both cases the EMF was determined by dividing the undercollection in each section as of March 2006, the end of the Sub 889 test year, by estimated North Carolina retail MWh sales, just as was done in the Sub 889 proceeding. Thus, it is clear that the EMFs were calculated using a net fuel cost undercollection that was determined in accordance with the assumption underlying the respective sections, i.e., with and without the Settlement. Moreover, as described previously, the only factor driving the differences in the Sub 868-related undercollections in each section, and thus the calculated EMFs, was the difference in the fuel revenue factor caused by the Sub 868 Settlement. Finally, as witness Maness testified, and as a matter of mathematics, the Settlement-related under-recovery built up during the initial collection period will be exactly offset by the Settlement-related true-up measured by the difference between the alternative EMFs (subject to differences in the amount of kWh sales billed during the period each rate is in effect). Thus, by the date the Rule R8-55(c)(2) fuel cost undercollection is trued-up through twelve months of billing of an approved EMF, the Settlement-related under-recovery will also be trued-up. In the case of the Sub 868 Settlement-related under-recovery, that date will be September 30, 2007. Thus, under the approach advocated by Public Staff witness Maness, the entire Settlement-related under-recovery will be recouped from ratepayers over the relevant collection period.

The interest calculation set forth on Maness Exhibit I, Schedule 2, thus fulfills the two interrelated requirements that the Commission has concluded must be met for the interest calculation to appropriately measure the impact of the Settlements. First, it calculates interest on the basis of the difference between the cash flows that occurred due to the Settlements and those that would have occurred absent the Settlements. Second, the Settlement-related under-recovery is determined solely by the differences in fuel revenue occurring due to the Settlements. In fact, the mathematics of witness Maness' schedule show that if the fuel cost (expense) factors were to be removed from the schedule entirely, the resulting interest amount of $8,217,000 would not change. For these reasons, the Commission concludes that the methodology used by witness Maness is consistent with the Commission's construction of the Sub 868 Settlement Agreement and that his recommended interest amount of $8,217,000 is appropriate for use in this proceeding.

Witness Barkley's assertion that witness Maness' method takes a portion of the Sub 889 EMF calculation related to Docket No. E-2, Sub 851 and reassigns it to the Sub 868-related portion of that calculation does not persuade the Commission to adopt the Company's recommended approach to determining the appropriate amount of interest to include under the Sub 868 Settlement Agreement. As witness Maness testified, and as Maness Exhibit I, Schedule 2, page 2, indicates, what witness Maness did was to recalculate the Sub 889 EMF as if the Sub 868 Settlement Agreement had not taken place. The result of such a calculation is that the Sub 868-related portion of the overall Sub 889 EMF calculation would have changed from an under-recovery of $26 million to an over-recovery of $34 million, a net change of $60 million. The Commission concludes that there was no "taking" from Sub 851. As witness Maness stated, his calculation did not "involve the Sub 851 numbers at all."

In summary, based on the evidence presented in this case, and the records in Subs 868 and 889, the Commission finds that the Public Staff's methodology for calculating interest reflects an appropriate reading of the Sub 868 Settlement Agreement, uses actual data to determine PEC's net cash flows and captures the differences in timing of fuel cost recovery with and without the Settlement Agreement, and is applied consistently throughout the period October 2005 through March 2007. The Public Staff's methodology also accomplishes exactly the purpose for which these types of interest accruals are designed: it puts the Company in the same financial position that it would have been in had the Settlement Agreement not been proposed and approved. The Commission, therefore, finds and concludes that it is appropriate to increase this fuel expense under-recovery by $8,217,000 to reflect interest through March 31, 2007, related to the Settlement Agreements approved in Docket No. E-2, Subs 868 and 889.

Thus, the Commission finds and concludes that PEC's under-recovery of prudently incurred fuel costs appropriate for recovery in this proceeding is $144,188,836, and the corresponding EMF to which PEC is entitled is 0.387 ¢/kWh, exclusive of gross receipts tax. Pursuant to Ordering Paragraph No. 3 of the Commission's September 25, 2006 Order in Docket No. E-2, Sub 889, the Commission therefore finds that the base fuel factor should be 2.288¢/kWh.

At this point herein, the Commission notes that CUCA filed a brief and motion for reconsideration pursuant to G.S. 62-80, in both Docket No. E-2, Sub 889 and in this Docket, on September 4, 2007. PEC filed a response to CUCA's motion on September 6, 2007.

The Commission has issued a separate order in Docket No. E-2, Sub 889 addressing CUCA's motion for reconsideration of the Commission Order dated September 25, 2006, in Docket No. E-2, Sub 889. However, in its filing, CUCA also includes the following alternative requests for relief:

> Even if the Commission declines to reconsider the 2006 Order, the Commission should either: (i) clarify the terms of the Settlement Agreement to specify that PEC shall not accrue interest upon the difference between the fuel factor computed in accordance with Settlement Agreement to go into effect October 1, 2007, 2.287 cents per kWh, and the fuel factor that PEC computed in accordance with its past procedures and set forth in Barkley Exhibit 5A, 2.358 cents per kWh; or (ii) conclude that the 2.287 cents per kWh is the reasonable fuel factor independent of the Settlement Agreement and in contravention of Barkley Exhibit 5A, which would prevent the accrual of interest even if such accrual is permitted by the Settlement Agreement because there would be no differential between the reasonable rate and the rate to be implemented in accordance with the Settlement Agreement.

In its response, PEC states that CUCA did not present any witness to address the issues raised in its brief, but rather simply asked a few questions on cross-examination related to these matters. PEC argues that simply asking a witness a question on cross-examination does not properly raise an issue for resolution by the Commission and that the arguments in CUCA's brief are not ripe for consideration.

The Commission rejects CUCA's alternative requests. The request by CUCA to clarify the interest provision of the Settlement Agreement is not ripe for decision, but not for the reason argued by PEC. This request is premature because PEC is not attempting to recover in rates any interest on the difference between the 2.287¢/kWh factor and the 2.358¢/kWh factor at this time. Such a request may be an issue in PEC's next fuel case, but no such request is before the Commission now. The request by CUCA to approve the 2.287¢/kWh base fuel factor as the reasonable fuel factor, independent of the Settlement Agreement, is contrary to the evidence in this case that PEC would be entitled to a base fuel factor equal to 2.358¢/kWh, absent the Settlement Agreement.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after October 1, 2007, PEC shall adjust the base fuel component in its North Carolina retail rates by an increment of 1.012¢/kWh (1.046¢/kWh including gross receipts tax) above the base fuel component approved in Docket No. E-2, Sub 537, and said increment shall remain in effect until changed by a subsequent order of the Commission in a general rate case or fuel case;

2. That PEC shall establish an EMF Rider as described herein to reflect an increment of 0.387¢/kWh (0.400¢/kWh including gross receipts tax) for retail rate schedules and applicable riders, and this Rider is to remain in effect for a 12-month period beginning October 1, 2007, and expiring on September 30, 2008;

3. That PEC shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustment approved herein not later than seven (7) working days from the date of this Order; and

4. That PEC shall notify its North Carolina retail customers of the fuel charge adjustments approved herein by including the customer notice attached as Appendix A as a bill message to be included on bills rendered during the Company's next normal billing cycle following the effective date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of September 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah092507.05

Chairman Edward S. Finley, Jr. concurs in part and dissents in part.

APPENDIX A

PEC BILL MESSAGE

The North Carolina Utilities Commission issued an Order on September 24, 2007, after public hearings and review, approving a fuel charge increase of approximately $48 million in the rates and charges paid by North Carolina retail customers of Progress Energy Carolinas, Inc. The rate increase will be effective for service rendered on and after October 1, 2007, and will result in a monthly rate increase of $1.30 for a typical customer using 1,000 kWh per month.

DOCKET NO. E-2, SUB 903

CHAIRMAN EDWARD S. FINLEY, JR., dissenting in part:

In its September 26, 2005 Order in Docket No. E-2, Sub 868, the Commission approved a base fuel factor of 1.775 cents/kWh for PEC for recovery of fuel costs during the upcoming twelve-month period, October 1, 2005 through September 30, 2006. The undisputed evidence before the Commission was that PEC would have been justified in charging a base fuel factor of 2.156 cents/kWh as authorized by G. S. 62-133.2 and NCUC Rule R8-55. PEC, however, had entered into a settlement agreement with intervenors in the case under which PEC agreed voluntarily to forego the revenues to which it otherwise would have been entitled had it employed the 2.156 cents/kWh. The effect of the Settlement Agreement and the Commission's approval of it was that PEC forewent millions of dollars in recovery of fuel costs within the upcoming twelve months and that its ratepayers enjoyed a deferral of their responsibility fully to reimburse PEC for those costs until as late as September 30, 2008. The purpose of the settlement was to spare ratepayers the financial burden of a rather precipitous increase in their rates. "[The settlement agreement] significantly mitigates the near term impact to PEC's customers of increasing cost of coal, natural gas, and rail transportation, and the Commission believes adopting the Agreement is in the public interest."

The Commission, in recognition of PEC's willingness to forego recovery of the fuel costs within the upcoming twelve month period, in the September 26, 2005 Order, authorized PEC to receive interest on the fuel cost underrecovery.

As the Commission stated:

> In recognition of the fact that a base fuel factor of 1.775 cents/kWh will, in all probability, cause PEC to significantly underrecover its fuel costs during the time period that the rates will be in effect, the Agreement provides that PEC shall be allowed to charge and collect interest at a rate of 6%, compounded annually on any underrecovery of fuel costs that occurs during the time period October 1, 2005, through September 30, 2006, that results from increasing the base fuel factor by 0.499 cents per kWh instead of 0.880 cents per kWh excluding

gross receipts tax, as proposed in its Application, until all such costs have been recovered.[1]

PEC, in accordance with the Commission's Order, charged only the 1.775 cents/kWh each month on retail MWh sales for the twelve-month period October 2005 through September 2006.

In PEC's 2006 fuel docket, E-2, Sub 889, the Commission approved an EMF of 0.490 cents/kWh. The EMF is a mechanism through which PEC collects the fuel cost underrecoveries experienced in the historical test year. G. S. 62-133.2(d) requires the Commission to incorporate in its fuel cost determination "the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period. . . . and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months. . . ." NCUC Rule R8-55(c)(2) provides that the "EMF rider will reflect the difference between reasonable and prudently incurred fuel cost and fuel related revenues that were actually realized during the test period under the fuel cost component of rates then in effect." Thus, the Sub 889 EMF was established to allow reimbursement resulting from PEC's assessing a 1.775 cents/kWh base fuel factor instead of 2.156 cents/kWh for the twelve month period ended September 30, 2006, as well as other test year underrecovered fuel costs. The 0.490 cents/kWh EMF approved in Sub 889 went into effect October 1, 2006. The historical test period upon which the Sub 889 rates were based was the twelve-month period April 1, 2005 through March 31, 2006. Consequently, PEC assessed the 1.775 cent/kWh only during the six month period October 2005 through March 2006 of the Sub 889 test period. The undisputed evidence in this docket is that PEC's <u>actual</u> fuel expense during the October 2005 through March 2006 six months period exceeded PEC's <u>actual</u> revenues arising from its assessing the 1.775 cents/kWh by $26 million. This underrecovery was set forth in the evidence in Sub 889 in Barkley Ex. No. 6 lines 8-13. This was the evidence the Commission had before it in Sub 889 when it established the 0.490 cents/kWh EMF to enable PEC to recover past unrecovered fuel expense in the upcoming twelve-month period, October 2006 through September 2007.

The question before the Commission in this docket for purposes of determining interest is how much of the October 2005 through March 2006 fuel cost underrecovery arising because PEC assessed 1.775 cents/kWh instead of 2.156 cents/kWh was reimbursed between October 1, 2006 through September 30, 2007 through PEC's assessment of the Sub 889 0.490 cents/kWh EMF. PEC argues that PEC's fuel expense during the six months exceeded PEC's fuel recovery revenues by $26 million, so the 0.490 EMF cents/kWh effectively only reduced the underrecovery by $26 million. The Public Staff argues that this $26 million reimbursed through the Sub 889 EMF should be increased by $34 million (to $60 million) to recognize the difference in cash flows during the six month period from those PEC actually experienced by assessing the 1.775 cents/kWh and those PEC would have experienced if no settlement had been reached and PEC had assessed the 2.156 cents/kWh. The Public Staff's method reduced the underrecovery more, thus resulting in $190,000 less in interest expense in this case. The Public Staff's method will result in PEC's receiving millions of dollars less in interest expense in succeeding cases. Under the Public Staff approach PEC had not only an actual $26 million underrecovery of fuel

[1] The base fuel factor the Commission approved for PEC in PEC's 2004 fuel docket, E-2, Sub 784, was 1.276 cents/kWh. Increasing 1.276 cents/kWh by 0.499 cents/kWh equals 1.775 cents/kWh. Had the 1.276 cents/kWh been increased by 0.880 cents/kWh, the factor would have been 2.156 cents/kWh.

costs, but also had a $34 million loss of foregone revenues during the six months because PEC charged 1.775 cents/kWh instead of 2.156 cents/kWh.

No Settlement Agreement provision or provisions in any Commission order expressly addresses the formula that PEC should use to calculate the appropriate interest. Nevertheless, the Commission's September 26, 2005 Order authorizes interest on "underrecovery of fuel costs." The Order makes no reference to foregone revenue cash flows. In addition, G. S. 62-133.2(d) dictates that the EMF should true up "experienced underrecovery" of fuel expense "incurred during the test period." Rule R8-55(c)(2) defines the EMF as the difference between fuel cost and fuel related revenues actually realized during the test period. In spite of this, the proposal for calculating interest advocated by the Public Staff adds to the actual October 2005 through March 2006 underrecovery between fuel revenues received and fuel expenses incurred reimbursed through the EMF "cash flows" that PEC "would have" received "if" PEC had charged 2.156/kWh. In my view this flies in the face of the letter and the intent of the Settlement Agreement authorizing interest, the Commission's Order approving it, and the express terms of G. S. 62-133.2(d) and NCUC Rule R8-55(c)(2). As I read the Settlement Agreement and the Commission's order, PEC is to receive interest on its underrecovery of fuel costs during the period the 1.775 cents/kWh factor was in effect. The effect of the settlement was that PEC forewent revenues for the recovery of fuel costs during this period that the evidence justified, so that ratepayers would have lower rates. In recognition of this concession, PEC was to receive interest on the "fuel cost underrecovery" experienced while the 1.775 cents/kWh was in effect. I find no suggestion in the Settlement Agreement or any Commission order that the interest calculated during the fuel cost underrecovery period is to be offset by any hypothetical foregone revenue cash flows.[1] Indeed, my reading of the Order suggests just the opposite. This is especially so because the statute and rule are written in terms of "underrecovery of fuel expense" and the "difference between incurred fuel costs and fuel related revenues actually realized during the test period."

Calculating interest in the manner advocated by the Public Staff and adopted by the majority two years after the fact through reliance on hypothetical foregone revenue cash flows inequitably deprives PEC, the party to the settlement that relinquished its rights, in favor of ratepayers, the party that benefited by the settlement's fundamental terms. What the Commission authorized in the September 26, 2005 Order by approving interest on unrecovered fuel costs until "all such costs have been recovered," the Commission is significantly taking back by attributing to PEC fuel cost recovery that the 0.490 cents/kWh EMF simply did not reimburse. If interest was to be calculated by attributing to PEC foregone revenue cash flows instead of actual fuel cost recovery in contradiction of what the statue and rule require, this should have been spelled out two years ago. PEC obviously has been deprived of the bargain it legitimately felt it had reached, and will not receive interest on the actual fuel costs

[1] Q. I may have misunderstood both of you which is why I am looking for some help. Why do you feel that Mr. Barkley's description of your calculation involved a misapprehension of some nature?

A. (Public Staff witness Maness) First of all, he speaks several times to my calculation as being a hypothetical calculation. I agree that one of the situations I used, the series of cash flows that would have occurred if the settlement had not been in effect is a hypothetical situation, but there is nothing hypothetical about the calculation. . .

Tr. p. 95.

underrecovery it experienced while the 1.775 cents/kWh factor was in effect. This is not the type of evenhanded regulatory treatment parties regulated by the Commission should receive.

The Public Staff, and the majority, which adopts the Public Staff position, places great reliance on the phrase "as a result of having adjusted the base fuel factor by 0.499 cents/kWh instead of 0.880 cents/kWh." This reliance is misplaced and unpersuasive. The phrase helps address the "what" and the "why" questions but not the "how" question, which is the question at issue. The phrase addresses the fact that interest will be paid on the under-recovery of fuel costs (the what) because the Commission approves a base fuel factor of 1.775 cents/kWh instead of 2.156 cents/kWh (the why), but says nothing about the formula to be used in calculating the amount of interest (the how).

The operative language from the September 26, 2005 order, after all, comes without significant modification from a joint proposed order submitted by PEC and the Public Staff on September 6, 2005. PEC and the Public Staff, the authors of the language, have come to no agreement on its intended meaning. For the majority to conclude two years later that the Commission, that authored nothing, intended for this language to mean that interest should be calculated through reliance on hypothetical cash flows simply defies credibility.

More importantly, the best indication of intent is the interpretation the parties and the Commission followed in Docket No. E-2, Sub 889 in 2006. When the parties agreed upon and the Commission authorized the 0.490 cents/kWh EMF in that docket, the EMF was established through reliance on the undisputed evidence in that case, Barkley Ex. No. 6, lines 8-13, to permit reimbursement of only $26 million of the underrecovery from assessing the 1.775 cents/kWh during the Sub 889 test year, not $60 million. The 0.490 cents/kWh has as its essential component, for purposes of the dispute in this case, a factor to reimburse only $26 million. Not only is it unfair and in contradiction of the ruling made in Sub 889 to in today's order modify that factor, to do so violates G. S. 62-133.2 requirements that the EMF reimburse only experienced underrecovery during the historical test year.

G. S. 62-133.2 is structured so that the EMF only allows PEC to obtain reimbursement for fuel cost underrecovery experienced in the historical twelve-month test period. The statute prohibits PEC from increasing the EMF to permit reimbursement of fuel cost underrecovery PEC experiences before the beginning or after the close of the historical test period. Yet the method for calculation of interest advanced by the Public Staff does just that—the method attributes to PEC fuel costs reimbursement that actually occurred before April 1, 2005, or after March 31, 2006.

The justification the Public Staff advances in support of its calculation is that it is theoretically superior to PEC's. The Public Staff asserts that "the Company's method essentially switches from using the differences in cash flows under each scenario to using the cash flow related to the with-agreement scenario. Second, it is clear that due to the overall operation of the fuel clause, specifically the true up provision, the $60 million lower cash flow during the initial Sub 868 collection period must be offset by an equally higher cash flow over the course of the Sub 868 true-up period". In particular Public Staff witness Maness asserts, "Contrastingly, the Company's approach reduced the Sub 868-related principal balance during the same period by only approximately $12 million (about six months' worth of its $26 million). Thus, the

Company reduced the principal balance for that period by an amount that is disproportionately lower than the amount indicated by the relevant cash flows."

This criticism is invalid and erroneous. PEC determines the Sub 889 test year underrecovery from assessing the 1.775 cents/kWh to be $26 million. PEC determines that the 0.490 Sub 889 EMF reimbursed PEC $12 million or six months of the $26 million underrecovery during the first six months the Sub 889 rates were in effect. The reason for this is obvious. The 1.775 cents/kWh was in effect for only six months of the Sub 889 test year. However, the 0.490 cents/kWh was in effect for the entire twelve months that the Sub 889 rates were in effect. The percentage of the 0.490 cents/kWh used to reimburse PEC for the underrecovery arising from employment of the 1.775 cents/kWh remains uniform each month of the period the Sub 889 rates are in effect. Therefore only six months of the $26 million, or $12 million, is reimbursed in the first six months. The remainder will be reimbursed in months seven through twelve.

The Public Staff's calculations are subject to the same Public Staff criticism. The Public Staff maintains that Sub 889 test year underrecovery is $60 million. Yet the Public Staff asserts that $27 million was reimbursed through the first six months of the period rates approved in Sub 889 were in effect. This is approximately the same percentage of reimbursement to underrecovery as the percentage PEC's numbers produce.

\s\ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

DOCKET NO. E-2, SUB 903

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Carolina Power & Light Company d/b/a	)	
Progress Energy Carolinas, Inc. for Authority to Adjust	)	ERRATA ORDER
its Electric Rates Pursuant to G.S. 62-133.2 and NCUC	)	
Rule R8-55	)	

BY THE CHAIRMAN: On September 25, 2007, the Commission issued an Order Approving Fuel Charge Adjustment in this proceeding. Appendix A attached to the Order contains a typographical error in referring to the date of the Order as September 24, 2007.

Therefore, the Chairman finds good cause to require that the date in the first sentence of Appendix A be changed from September 24, 2007 to September 25, 2007.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of September, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah092607.04

DOCKET NO. E-22, SUB 444

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of Dominion North Carolina Power for Authority to Adjust its Electric Rates Pursuant to G.S. 62-133.2 and NCUC rule R8-55	) ORDER APPROVING) FUEL CHARGE) ADJUSTMENT

HEARD: Thursday, November 8, 2007, beginning at 9:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Robert V. Owens, Jr., and Sam J. Ervin, IV

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 225 Hillsborough Place, Suite 160, Raleigh, North Carolina 27603

For the Carolina Industrial Group for Fair Utility Rates I:

Ralph McDonald, Bailey and Dixon, LLP, Post Office Box 1351, Raleigh, North Carolina 27602-1351

For Nucor Steel-Hertford, a division of Nucor Corporation:

Joseph W. Eason, Nelson, Mullins, Riley & Scarborough, LLP, 4140 ParkLake Avenue, Suite 200, Post Office Box 30519, Raleigh, North Carolina 27622-0519

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff-North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

BY THE COMMISSION: G.S. 62-133.2 requires the North Carolina Utilities Commission to hold a hearing for each electric utility engaged in the generation and production of electric power by fossil or nuclear fuel for the purpose of determining whether an increment or decrement rider is required to reflect actual changes in the cost of fuel and the fuel component of purchased power over or under the base fuel component established in the utility's last general rate case. In addition, the Commission is required to incorporate in its fuel cost determination the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test year. The last general rate case Order for Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion NC Power or the Company), was issued by the Commission on March 18, 2005, in Docket No. E-22, Sub 412. The last Order approving a fuel charge adjustment for the Company was issued on December 22, 2006 in Docket No. E-22, Sub 436.

On September 14, 2007, Dominion NC Power filed the direct testimony and exhibits of Wesley S. Gregory, Anne M. Tracy, Jack E. Streightiff and Alan L. Meekins pursuant to G.S. § 62-133.2 and Commission Rule R8-55 relating to fuel charge adjustments for electric utilities. The Company also filed the information and work papers required by Commission Rule R8-55(d).

On September 18, 2007, the Commission issued an Order Scheduling Hearing and Requiring Public Notice. Nucor Steel-Hertford (Nucor), a division of Nucor Corporation, filed a petition to intervene on September 21, 2007, and the Carolina Group for Fair Utility Rates (CIGFUR I) filed a petition to intervene on September 24, 2007, both of which were allowed by Commission Order issued September 26, 2007.

On October 8, 2007, Dominion NC Power filed revised direct testimony and exhibit of Alan L. Meekins. On October 19, 2007, Dominion NC Power filed Notice of Affidavits for all four of its witnesses and the Public Staff of the North Carolina Utilities Commission (Public Staff) filed a motion for extension of time, requesting a due date of October 26, 2007, for Nucor's direct testimony; a due date of October 29, 2007, for the Public Staff's testimony; and a due date of November 5, 2007, for Dominion NC Power's rebuttal testimony. By Order dated October 24, 2007, the Commission granted the Public Staff's motion for an extension of time.

Roy Cooper, Attorney General filed Notice of Intervention on October 22, 2007. The intervention of the Attorney General is recognized pursuant to G.S. 62-20. The intervention of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R-19(3).

On October 26, 2007, Nucor filed the confidential and redacted testimony and exhibits of Dr. Mathew J. Morey. The Public Staff filed a notice of affidavits; the affidavit and exhibits of Randy T. Edwards, Staff Accountant; and the affidavit of Thomas S. Lam, Electric Engineer, on October 29, 2007. On November 5, 2007, the Public Staff filed the revised affidavits of Mr. Edwards and Mr. Lam.

On October 29, 2007, the Company filed its Affidavits of Publication, and on November 5, 2007, it filed the rebuttal testimony of Alan L. Meekins.

At the hearing, the prefiled direct testimony and rebuttal testimony of the Company's witnesses, the revised affidavits and exhibits of the Public Staff's witnesses, and the testimony and exhibits of Nucor's witnesses were admitted into evidence. No public witnesses appeared at the hearing.

On December 7, 2007, the Public Staff filed a motion requesting that the due date for the PJM integration study portion of the proposed orders and/or briefs be extended until Tuesday, December 18, 2007. No change in the due date for the remainder of the proposed orders and/or briefs was requested. The Commission granted the motion by Order dated December 10, 2007.

Based upon the verified Application, the evidence adduced at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Dominion NC Power is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. Dominion NC Power is lawfully before this Commission based on its Application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 2007.

3. The Company's fuel procurement and purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 81,760,358 MWh.

5. The test period per book system generation is 85,628,797 MWh, which includes various types of generation as follows:

Generation Type	MWh
Coal	31,662,472
Combined Cycle and Combustion Turbine	4,321,056
Heavy Oil	1,358,993
Nuclear	26,432,096
Hydro	3,175,089
Pumped Storage (Pumping)	(3,246,902)
Power Transactions	
NUG	9,816,570
Other	13,011,521
Sales for Resale	(902,098)

6. The nuclear capacity factor appropriate for use in this proceeding is 93.60%, which is the estimated nuclear capacity factor for the year ending December 31, 2008.

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

7. The appropriate adjusted test period system sales for use in this proceeding are 82,809,227 MWh.

8. The appropriate adjusted test period system generation for use in this proceeding is 86,752,397 MWh, which is categorized as follows:

Generation Type	MWh
Coal	32,273,641
Combined Cycle and Combustion Turbine	4,404,436
Heavy Oil	1,385,245
Nuclear	26,394,233
Hydro	3,175,089
Pumped Storage (Pumping)	(3,246,902)
Power Transactions	
NUG	10,006,073
Other	13,262,680
Sales for Resale	(902,098)

9. The appropriate fuel prices for use in this proceeding are as follows:

A. $22.80/MWh for coal;
B. $4.03/MWh for nuclear;
C. $81.51/MWh for heavy oil;
D. $74.77/MWh for combined cycle and combustion turbine fuel;
E. $30.12/MWh for the fuel price of power transactions; and,
F. A zero fuel price for hydro and pumped storage.

10. The adjusted test period system fuel expense appropriate for use in this proceeding is $1,719,504,873.

11. The appropriate fuel factor for purposes of this proceeding is 2.076¢/kWh, excluding gross receipts tax, or 2.144¢/kWh, including gross receipts tax.

12. The Commission will issue a subsequent order, if necessary, to address unresolved issues concerning the parameters of and methodology for the study by Dominion NC Power relating to the impact of the Company's integration into PJM on the Company's fuel expenses.

13. Setting the fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 58% of the energy portion of the purchase price is reasonable for use in this proceeding.

14. The appropriate North Carolina test period jurisdictional fuel expense undercollection is $3,150,194. The adjusted North Carolina jurisdictional test year sales are 4,238,954 MWh.

15. The appropriate Experience Modification Factor (EMF) for purposes of this proceeding is an increment of 0.074¢/kWh, excluding gross receipts tax, or 0.077¢/kWh, including gross receipts tax.

16. The final net fuel factor to be billed to Dominion NC Power's North Carolina retail customers during the 2007 billing period is 2.150¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 2.076¢/kWh, and the EMF increment of 0.074¢/kWh, or 2.221¢/kWh, including gross receipts tax, consisting of the prospective fuel factor of 2.144¢/kWh and the EMF increment of 0.077¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, jurisdictional, and procedural in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G. S. 62-133.2(c) sets out the verified, annualized information that each electric utility is required to furnish the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. Commission Rule R8-55(b) prescribes the 12 months ending June 30 as the test period for NC Power. The Company's filing was based on the 12 months ended June 30, 2007.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every ten years and each time the utility's fuel procurement practices change. The Company's current fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, on December 30, 2003. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

No party elicited evidence contesting the reasonableness of the Company's fuel procurement and power purchasing practices. Based on the fuel procurement practices report and in the absence of evidence to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence for these findings of fact is contained in the testimony of Company witnesses Tracy and Streightiff and the revised affidavit of Public Staff witness Lam.

Witness Streightiff testified that the test period per book system sales were 81,760,358 MWh and witness Tracy testified that the test period per book system generation was 85,628,797 MWh. The test period per book system generation is categorized as follows:

Generation Type	MWh
Coal	31,662,472
Combined Cycle and Combustion Turbine	4,321,056
Heavy Oil	1,358,993
Nuclear	26,432,096
Hydro	3,175,089
Pumped Storage (Pumping)	(3,246,902)
Power Transactions	
NUG	9,816,570
Other	13,011,521
Sales for Resale	(902,098)

Commission Rule R8-55(c)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Reliability Council's (NERC) Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility's nuclear generating facilities and any unusual events.

Company witness Tracy testified that, for the July 1, 2006, to June 30, 2007, test period, North Anna Unit 1 performed at a net capacity factor of 98.41%, North Anna Unit 2 performed at a net capacity factor of 88.48%, Surry Unit 1 performed at a factor of 99.41% and Surry Unit 2 performed at a factor of 88.70%. She testified that all four of the Company's nuclear units exceeded the NERC 2001-2005 five-year industry average net capacity factor of 87.68% for units of similar size. She further testified that, for the 12 months ending December 31, 2008, North Anna Unit 1 and Surry Unit 1 are projected to operate at net capacity factors of 97.3%, and North Anna Unit 2 and Surry Unit 2 are projected to operate at 89.86%.

Public Staff witness Lam testified that the Company's proposed fuel factor is based on a 93.60% system nuclear capacity factor, which is what the Company anticipates for the 12 months beginning January 1, 2008, the period the new rates will be in effect. The actual system nuclear capacity factor for the test year was 93.75%. In comparison, the latest NERC five-year (2001-2005) weighted average nuclear capacity factor for pressurized water reactors is 87.68%. Witness Lam testified that he believed the proposed 93.60% nuclear capacity factor to be more representative of the factor the Company can reasonably be expected to achieve during the period that the fuel factor is in effect than a capacity factor based on the NERC five-year average. No other party offered or elicited testimony concerning the issue of the appropriate normalized nuclear capacity factor for use in this proceeding.

The Commission concludes that the July 1, 2006, to June 30, 2007, test period levels of sales and generation are reasonable and appropriate for use in this proceeding, as is the proposed 93.60% normalized system nuclear capacity factor.

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Streightiff.

Witness Steightiff testified that the Company's system sales for the twelve months ended June 30, 2007, were adjusted for weather normalization, customer growth and increased usage in accordance with Commission Rule R8-55(d)(2). Witness Streightiff adjusted total Company sales by 1,048,869 MWh. This adjustment is the sum of adjustments for customer growth, increased usage, and weather normalization of 504,023 MWh, 290,029 MWh and 255,779 MWh, respectively, and an adjustment of (962) MWh from the restatement of non-jurisdictional ODEC sales from production level to sales level. The Public Staff reviewed and accepted these adjustments.

Based on the foregoing evidence, the Commission concludes that these adjustments are reasonable and appropriate adjustments for use in this proceeding. Therefore, the Company's adjusted system sales for the twelve months ended June 30, 2007, were 82,809,227 MWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is contained in the testimony of Company witness Tracy and the revised affidavit of Public Staff witness Lam.

Company witness Tracy presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2007, due to weather normalization, customer growth, and increased usage of 1,123,600 MWh to arrive at her adjusted generation level of 86,752,397 MWh. Public Staff witness Lam accepted witness Tracy's adjusted generation level, which includes various types of generation as follows:

Generation Type	MWh
Coal	32,273,641
Combined Cycle and	
Combustion Turbine	4,404,436
Heavy Oil	1,385,245
Nuclear	26,394,233
Hydro	3,175,089
Pumped Storage (Pumping)	(3,246,902)
Power Transactions	
NUG	10,006,073
Other	13,262,680
Sales for Resale	(902,098)

The Commission concludes that it is reasonable and appropriate to use 86,752,397 MWh as the amount of adjusted test period system generation for purposes of this proceeding.

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9-11

The evidence for this finding of fact is contained in the testimony of Company witnesses Tracy and Streightiff and the revised affidavit of Public Staff witness Lam.

Company Witness Tracy testified that the Company's proposed fuel factor is based on June, 2007 fuel prices, with appropriate adjustments, as follows: (1) a coal price of $22.80/MWH; (2) a nuclear fuel price of $4.03/MWh; (3) a heavy oil price of $81.51/MWh; (4) a combined cycle and internal combustion turbine price of $74.77/MWh; (5) a price for power transactions $30.12/MWh; and (6) a zero price for hydro and pumped storage.

Public Staff witness Lam testified that he had reviewed the Company's test year fuel prices and determined that they were reasonable. No other party contested these fuel prices. Therefore, based upon the foregoing, the Commission concludes that the fuel prices recommended by Company witness Tracy and Public Staff witness Lam are reasonable and appropriate for use in this proceeding.

Company witness Tracy testified that she calculated the level of normalized fuel expenses by multiplying the normalized generation amounts for the Company's generating units by actual June, 2007 fuel prices, with the following exceptions: (1) due to an accounting adjustment, coal expense was based upon the 12-month average expense; (2) NUG expense was set equal to the 12 months ended June, 2007 expense; and (3) purchased power expense was based upon the 12 months ended June, 2007 average fuel expense. Witness Tracy further testified that test year normalized fuel expense was $1,719,504,873. Company witness Streightiff calculated the fuel factor proposed for the 12 months ended December 31, 2008, by dividing the normalized fuel expense of $1,719,504,873 by the adjusted level of test year system MWh sales (82,809,227 MWh). This calculation resulted in a proposed fuel factor of 2.076¢/kWh (excluding gross receipts tax) and 2.144¢/kWh (including gross receipts tax). Public Staff witness Lam recommended approval of the proposed 2.076¢/kWh fuel factor. When this fuel factor is reduced by 1.647¢/kWh (excluding gross receipts tax) and 1.701/kWh (including gross receipts tax), the base fuel component approved in the Company's most recent general rate case, the resulting fuel cost rider (Rider A) is 0.429¢/kWh (excluding gross receipts tax) and 0.443¢/kWh (including gross receipts tax).

The Commission concludes that adjusted fuel test period expenses of $1,719,504,873 and a fuel cost rider (Rider A) of 0.429¢/kWh, excluding gross receipts tax, or 0.443¢/kWh, including gross receipts tax, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Company witness Meekins sponsored and testified concerning a study submitted by Dominion NC Power showing the impact of the Company's integration into PJM on its North Carolina retail fuel expenses (the PJM study). The purpose of the PJM study is to demonstrate compliance with certain provisions of the Commission Order dated April 19, 2005, in Docket No. E-22, Sub 418, in which the Commission allowed Dominion NC Power to transfer control of its transmission assets in North Carolina. The PJM study has also been addressed by the

Commission in the Company's two most recent annual fuel clause adjustment proceedings, Docket No. E-22, Sub 428 and Docket No. E-22, Sub 436. Nucor witness Morey testified that the PJM study submitted by the Company contained methodological problems that render it unreliable for purposes of determining the extent to which Dominion NC Power's fuel costs are affected by its integration into PJM. Witness Morey recommended that the Commission order the Company to apply the methods which he proposed in future fuel adjustment proceedings in which the impact of the Company's integration into PJM was at issue. Public Staff witness Lam testified that the Public Staff needed additional time to review the methodological issues raised by Nucor and that the Public Staff would take a position on the appropriate methodology at the hearing or in its proposed order. Finally, Company witness Meekins testified in rebuttal to the issues raised by Nucor witness Morey.

On December 7, 2007, the Public Staff filed a motion requesting an extension of time for filing that portion of parties' proposed orders and briefs addressing the PJM study. According to the motion, the Public Staff had initiated discussions among the parties about the appropriate parameters of and methodology for the PJM study, including whether the parties could at least narrow the disputed issues. Due to the complexity of the issues relating to the PJM study, the Public Staff stated that additional time was needed for further discussions. On December 10, 2007, the Commission issued an Order granting an extension of time to all parties for the filing of that portion of parties' proposed orders and briefs relating to the PJM study.

Therefore, the Commission finds and concludes that it will issue a subsequent order, if necessary, to address unresolved issues concerning the parameters of and methodology of the PJM study after receiving and reviewing the parties' briefs and proposed orders relating to this subject.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the affidavit of Public Staff witness Edwards. Witness Edwards stated that, during the test year, Dominion NC Power purchased power from suppliers that did not provide Dominion NC Power with the actual fuel costs associated with those purchases. He also stated that a similar situation has occurred in each of the fuel proceedings for Duke Energy Carolinas, LLC (Duke), Progress Energy Carolinas, Inc. (PEC), and Dominion NC Power since 1996.

Witness Edwards stated that, for purposes of determining Dominion NC Power's Experience Modification Factor (EMF) in this proceeding, the Public Staff recommended that the Commission adopt a percentage of 58%, as proposed in Dominion NC Power's Application, to be applied to purchases from power marketers and to purchases from other sellers that did not provide Dominion NC Power with actual fuel costs. To determine this percentage, the Public Staff performed a review of the fuel component of off-system sales made by Duke and PEC for the twelve months ended December 31, 2006. These sales are set forth in each of the utilities' Monthly Fuel Reports.

Witness Edwards explained that, unlike in past years, the off-system sales for Dominion NC Power were not utilized for purposes of calculating the fuel-to-energy percentage. Witness

Edwards stated a two-fold rationale for excluding Dominion NC Power from the Public Staff's analysis. First, evaluation of the data indicated that there were only two Dominion NC Power off-system sales transactions that were eligible for inclusion in the analysis used to determine the appropriate fuel-to-energy percentage. One of those two transactions appeared to utilize a "proxy percentage" to determine the fuel component of total energy rather than actual fuel costs. The other transaction had an immaterial impact on the analysis. Second, neither of the transactions recorded megawatt hours for the associated off-system sales. Thus, neither of these transactions provided meaningful data for purposes of the Public Staff's analysis. Therefore, the Public Staff considered it reasonable to exclude these transactions from the determination of the fuel-to-energy percentage for purposes of its analysis in this proceeding.

Witness Edwards indicated that, despite the removal of Dominion NC Power transactions from this analysis, the analysis performed by the Public Staff is similar to that performed for the 1997 Stipulation addressing this matter (which was applicable to the utilities' 1997 and 1998 fuel proceedings) and the similar 1999 Stipulation filed in Docket No. E-2, Sub 748 (applicable to the 1999, 2000, and 2001 fuel cost proceedings). Similar analyses were performed for the fuel proceedings held in 2002 through 2006. Witness Edwards indicated that the methodology used for each of the above-mentioned Stipulations and subsequent fuel adjustment proceedings had been accepted by the Commission as reasonable in each fuel adjustment case since the beginning of 1997.

Witness Edwards stated that, as part of its current review, the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 56.61% to 60.53%, as set forth in Edwards Exhibit I. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel ratio should be 58%.

G.S. 62-133.2 requires that purchased power-related costs recovered through fuel proceedings consist of only the fuel cost component of those purchases. However, in its Order in Duke's 1996 fuel proceeding, the Commission stated that whether a proxy for actual fuel costs associated with these types of purchases would be acceptable in a future fuel proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available."

Public Staff witness Edwards stated that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the proxy fuel cost as described above. He further stated that, because the sales made by marketers and other suppliers utilize the same types of generation resources that the utilities use to make their own sales, the Public Staff believes that it is reasonable to assume for purposes of these proceedings that the fuel-to-energy percentage inherent in the purchases made by the utilities is similar to the percentage exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel percentage was derived from the Monthly Fuel Reports filed with the Commission and, in the opinion of the Public Staff, is reasonably reliable. Finally, witness Edwards stated that the Public Staff is unaware of any alternative information currently available concerning the fuel cost component of sales made by marketers and similar suppliers to utilities. Therefore, according to witness Edwards, the Public Staff believes that the methodology used in past Stipulations and in the analysis for this proceeding meets the criteria set forth in the 1996 Duke Order. No other party offered or elicited evidence contrary to the Public Staff's position.

The Commission concludes, as it has in past dockets, that the methodology underlying the 1997 and 1999 Marketer Stipulations, i.e., the use of the utilities' own off-system sales to determine the proxy fuel cost for purchases from entities that do not provide actual fuel costs, is reasonable and satisfies the requirements set forth in the 1996 Duke fuel case order for purposes of this proceeding. First, the results of applying the methodology are acceptable under G.S. 62-133.2. As Public Staff witness Edwards stated, the sales made by marketers and other relevant suppliers are sourced from the same types of generation resources that the utilities regulated by this Commission use to make their own sales. The Commission, therefore, finds it reasonable to assume for purposes of this proceeding that the fuel-to-energy percentage exhibited by the utilities' sales is similar to the percentage inherent in the sales made to Dominion NC Power from the same types of generating resources. Second, the Commission concludes that the information used by the parties to derive the fuel ratio is reasonably reliable. According to the affidavit of witness Edwards, the data was derived from the Monthly Fuel Reports filed by the utilities with the Commission. The Monthly Fuel Reports are public reports taken from the utilities' financial records and are subject to Commission review. Therefore, the Commission concludes that the methodology underlying the 1997 and 1999 Marketer Stipulations, as used in prior cases, meets the criteria set forth in the 1996 Duke fuel case order and is a reasonable method for determining the proxy fuel cost for purposes of this proceeding.

Given the fact that the Commission has concluded that the use of the methodology underlying the 1997 and 1999 Marketer Stipulations is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel percentage to be used in this case.

The Public Staff's most recent analyses of off-system sales information resulted in fuel percentages ranging from 56.61% to 60.53%. Based on these results, the Public Staff recommended that 58% be used as an appropriate and reasonable fuel percentage for purposes of this proceeding. No party presented or elicited evidence in opposition to the Public Staff's recommendation.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 58% fuel ratio as the basis for determining the proxy fuel costs for purchases from power marketers and other suppliers that do not provide actual fuel costs.

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 Company witnesses Gregory and Streightiff and the revised affidavits of Public Staff witnesses Edwards and Lam.

Company witness Gregory testified that Dominion NC Power under-collected its fuel expenses by $3,343,462 during the test year ending June 30, 2007. Company witness Streightiff testified that the appropriate adjusted North Carolina jurisdictional test year sales were 4,238,954 MWh and that the appropriate EMF was 0.082¢/kWh (including gross receipts tax).

Public Staff witness Edwards investigated the EMF to determine whether Dominion NC Power properly determined its fuel costs during the test period. Witness Edward's investigation resulted in five adjustments. The first adjustment modified the fuel portion of off-system sales revenue during the test period to reflect the sourcing of those sales from purchases affected by the marketer percentage of 58%, and resulted in a reduction to Dominion NC Power's North Carolina retail fuel expense in the amount of $90,565. The second adjustment related to the removal of a purchased power amount applicable to a month preceding the test year and resulted in a reduction to fuel expense in the amount of $88,033. The third adjustment involved the correction of an error related to the estimate of July 2006 purchased power fuel costs and resulted in a reduction to fuel expense in the amount of $14,872. The fourth adjustment related to Dominion NC Power's calculation of purchased power fuel expense related to the 58% marketer percentage and resulted in an increase in fuel expense in the amount of $11,678. The fifth adjustment corrected the megawatt hours and revenue used in Dominion NC Power's calculation of Financial Transmission Rights (FTR) revenue to be credited to purchased power and resulted in a reduction to fuel expense in the amount of $11,476. The Public Staff's adjustments, taken as a whole, reduced the total test year fuel underrecovery from $3,343,462 to $3,150,194. No party presented or elicited evidence in opposition to the Public Staff's recommended adjustments and, upon examination, the Commission finds them to be reasonable and appropriate for purposes of this proceeding.

G.S. 62-133.2(d) provides, in part, that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period...in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

Company witness Streightiff indicated that the appropriate and reasonable level of adjusted North Carolina retail sales for the test year is 4,238,954 MWh. No party disagreed with this sales level, and the Commission finds it reasonable. The $3,150,194 under-recovered fuel expense can thus be divided by the adjusted North Carolina jurisdictional sales of 4,238,954 MWh to arrive at an EMF increment of 0.074¢/kWh, excluding gross receipts tax, or 0.077¢/kWh, including gross receipts tax.

The Commission concludes that the EMF increments of 0.074¢/kWh, excluding gross receipts tax, or 0.077¢/kWh, including gross receipts tax, are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence supporting this finding of fact is cumulative and is contained in the testimony and exhibits of Company witnesses Gregory and Streightiff and the revised affidavits and exhibits of Public Staff witnesses Edwards and Lam.

Based upon the above findings, the Commission finds and concludes that the final net fuel factor appropriate for purposes of this proceeding is 2.150¢/kWh, excluding gross receipts tax, and 2.221¢/kwh, including gross receipts tax.

This final net fuel factor is determined as follows:

Normalized System Fuel Expense	$1,719,504,873
System kWh Sales at Sales Level	82,809,227,557
Test Year North Carolina Retail Fuel Underrecovery	$3,150,194
North Carolina Retail kWh Sales at Sales Level	4,238,954,265
Base Fuel Component Approved in Docket No. E-22, Sub 412 (cents per kWh)	1.647
Gross Receipts Tax Factor	1.03327

Base Fuel Component including gross receipts tax = 1.701¢/kWh

Fuel Cost Rider A (excluding gross receipts tax)
= [($1,719,504,873)/82,809,227,557 kWh] - 1.647¢/kWh = 0.429¢/kWh

Fuel Cost Rider A (including gross receipts tax)
= 0.429¢/kWh x 1.03327 = 0.443¢/kWh

Fuel Cost Rider B (excluding gross receipts tax)
= [(3,150,194)/4,238,954,265 kWh = 0.074¢/kWh

Fuel Cost Rider B (including gross receipts tax)
= 0.074¢/kWh x 1.03327 = 0.077¢/kWh

	Effective 1/1/2008 (Including Gross Receipts Tax)
Base Fuel Factor	1.701
EMF/Rider B	0.077
Fuel Cost Rider A	0.443
FINAL FUEL FACTOR	2.221

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2008, Dominion NC Power shall adjust the base fuel component in its North Carolina retail rates approved in Docket No. E-22, Sub 412, by an increment Rider A of 0.429¢/kWh, excluding gross receipts tax, or 0.443¢/kWh, including gross receipts tax;

2. That an EMF Rider increment (Rider B) of 0.074¢/kWh, excluding gross receipts tax, or 0.077¢/kWh, including gross receipts tax, shall be instituted and remain in effect for usage from January 1, 2008, until December 31, 2008;

3. That Dominion NC Power shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein not later than five (5) working days from the date of receipt of this Order;

4. That Dominion NC Power shall notify its North Carolina retail customers of the rate adjustments approved in this proceeding by including the Notice to Customers of Rate Increase attached to this Order as Appendix A as a bill insert with customer bills rendered during the next regularly scheduled billing cycle; and

5. That Dominion NC Power shall file a PJM study in its next fuel adjustment proceeding to demonstrate compliance with the conditions set forth in the ordering paragraphs of the Commission Order dated April 19, 2005, in Docket No. E-22, Sub 418.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th day of December 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr121207.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-22, SUB 444

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Dominion North Carolina	)	
Power for Authority to Adjust its Electric	)	NOTICE TO CUSTOMERS
Rates Pursuant to G.S. 62-133.2 and	)	OF RATE DECREASE
NCUC Rule R8-55	)	

ELECTRIC – ADJUSTMENT OF RATES/CHARGES

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 20, 2007, after public hearing, approving a $14,921,119 decrease in the annual rates and charges paid by customers of Virginia Electric and Power Company, d/b/a in North Carolina as Dominion North Carolina Power. The rate decrease will be effective for usage on and after January 1, 2008. The rate decrease was approved by the Commission after review of Dominion North Carolina Power's fuel expenses during the 12-month test period ended June 30, 2007, and represents changes experienced by Dominion North Carolina Power with respect to its reasonable costs of fuel and the fuel component of purchased power.

The change in the approved fuel charge will result in a monthly net decrease of approximately $3.52 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the _20th day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr121207.01

ELECTRIC – ELECTRIC GENERATION CERTIFICATE

DOCKET NO. E-7, SUB 790

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC,	)	ORDER GRANTING
For Approval for an Electric Generation	)	CERTIFICATE OF
Certificate of Public Convenience and	)	PUBLIC CONVENIENCE
Necessity to Construct Two 800-MW State-	)	AND NECESSITY
Of-the-Art Coal Units for Cliffside Project	)	WITH CONDITIONS

HEARD IN: Charlotte-Mecklenburg Government Center, 600 E. Fourth Street, Charlotte, North Carolina on August 30, 2006; Council Chambers, Shelby City Hall, 300 S. Washington Street, Shelby, North Carolina on August 31, 2006; Commission Hearing Room, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina on September 12-14, 2006; and
Public Library of Charlotte and Mecklenburg County, Francis Auditorium, 310 N. Tryon Street, Charlotte, North Carolina on January 10, 2007; Council Chambers, Shelby City Hall, 300 S. Washington Street, Shelby, North Carolina on January 11, 2007; Commission Hearing Room, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina on January 17-19, 2007

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, James Y. Kerr, II, Howard N. Lee, and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lawrence B. Somers, Assistant General Counsel, Duke Energy Corporation, 526 S. Church Street, Charlotte, North Carolina 28202

Robert W. Kaylor, Law Office of Robert W. Kaylor, PA, 225 Hillsborough Street, Suite 160, Raleigh, North Carolina 27603

Kevin C. Greene and Brandon F. Marzo, Troutman Sanders, LLP, Bank of America Plaza, 600 Peachtree Street, N.E., Suite 5200, Atlanta, Georgia 30308-2216

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Robert S. Gillam and William E. Grantmyre, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Leonard G. Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, P.C., 434 Fayetteville Street Mall, Suite 1735, Raleigh, North Carolina 27601

For Carolina Industrial Groups for Fair Utility Rates:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1351

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

Len S. Anthony, Deputy General Counsel, Progress Energy Carolinas, 410 S. Wilmington Street, Raleigh, North Carolina 27602

For North Carolina Waste Awareness and Reduction Network, Inc.:

John Runkle, Post Office Box 3793, Chapel Hill, North Carolina 27515

For Environmental Defense and Southern Environmental Law Center:

Marily Nixon and Gudrun Thompson, Southern Environmental Law Center, 200 W. Franklin Street, Suite 330, Chapel Hill, North Carolina 27516

For North Carolina Sustainable Energy Association:

T. LaFontine Odom, Sr., The Odom Firm, PLLC, 1109 Greenwood Cliff, Charlotte, North Carolina 28204

For Southern Alliance for Clean Energy:

Gary A. Davis, Gary A. Davis & Associates, Post Office Box 649, Hot Springs, North Carolina 28743

For Wells Eddleman:

Pro se

BY THE COMMISSION: On May 11, 2005, Duke Power, a division of Duke Energy Corporation, filed with the North Carolina Utilities Commission (Commission) preliminary information pursuant to Commission Rule R8-61(a) concerning plans to seek a certificate of public convenience and necessity authorizing the construction of two 800-megawatt (MW) coal-fired electric generating facilities to be located at the existing Cliffside Steam Station, situated on the border of Cleveland and Rutherford Counties, North Carolina, together with certain related transmission facilities.

On June 2, 2006, acting pursuant to G.S. 62-110.1(a) and Commission Rule R8-61(b), Duke Power Company LLC d/b/a Duke Energy Carolinas, LLC (Duke or the Company)[1] filed an application seeking the issuance of a certificate for construction of the proposed generation and transmission facilities described in the May 11, 2005 informational filing. Duke's application was accompanied by the prefiled testimony and exhibits of James E. Rogers, President and Chief Executive Officer of Duke Energy Corporation; Ellen T. Ruff, President of Duke Energy Carolinas; Janice D. Hager, Vice President of Rates and Regulatory Affairs for Duke Energy Carolinas; Mark R. Griffith, a Vice President of Global Energy Advisors, a business unit of Global Energy Decisions; and William R. McCollum, Jr., Group Vice President of Regulated Fossil/Hydro Generation for Duke Energy Corporation.

On July 6, 2006, the Commission entered an order scheduling public hearings and an evidentiary hearing, establishing deadlines for the filing of petitions to intervene and testimony, and requiring appropriate public notice.

The following organizations filed petitions to intervene and were authorized to intervene: Carolina Utility Customers Association, Inc. (CUCA); North Carolina Waste Awareness and Reduction Network, Inc. (NCWARN); Carolina Industrial Groups for Fair Utility Rates (CIGFUR III); Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.; Southern Alliance for Clean Energy (SACE); Environmental Defense (ED); Southern Environmental Law Center (SELC); North Carolina Municipal Power Agency Number 1; North Carolina Eastern Municipal Power Agency, Inc.; and North Carolina Sustainable Energy Association, Inc. (NCSEA). The Attorney General filed notice of intervention under G.S. 62-20, and the intervention of the Public Staff has been recognized under G.S. 62-15(d) and Commission Rule R1-19(e).

On August 17, 2006, SACE filed a motion for an extension of time to file its testimony and a postponement of the evidentiary hearing. On August 18, 2006, ED and SELC filed a joint motion seeking similar relief, and on August 22, 2006, NCWARN moved to postpone the evidentiary hearing. On August 22, 2006, Duke filed a response opposing these motions. On August 24, 2006, the Commission entered an order granting extensions of time for the filing of intervenor testimony and rebuttal testimony but declining to postpone the evidentiary hearing.

Public hearings were held as scheduled on August 30, 2006, in Charlotte and on August 31, 2006, in Shelby. The following public witnesses testified at the Charlotte hearing: Dave Barnhardt, Bob Thomason, Beth Henry, Sally Thomas, Chatham Olive, June Blotnick, Christal Wagner, Liz Veazey, Kathryn Kuppers, Bob Morgan, Elyse Hillegass, Angie Lawry, Willie Dodson, Summer Rose, Robin Koch, Rita Heath, Nick Hendricks, Todd Glasier, Susan Tompkins, Maarten Pennink, John Avery, Diana Movius, Tracey Crowe, Renee Reese, Katie

[1] In connection with the merger of Duke Energy Corporation and Cinergy Corporation approved in Docket No. E-7, Sub 795, Duke Energy Corporation was converted into a limited liability company, Duke Power Company LLC, d/b/a Duke Energy Carolinas, LLC. On October 4, 2006, the Company notified the Commission of its formal name change to Duke Energy Carolinas, LLC.

Oates, Ivory Clabaugh, Tom Lannin, Tammy Bostick, Colin Hagan, Harry Taylor, and Faeiz Hindi. The following public witnesses testified at the Shelby hearing: Walter Dalton, Harold Stallcup, Bob England, Rick Roper, Tim Moore, Bill Hall, Jerry Self, Charles Hill, Robert Hawkins, Mary Accor, Vic Sarratt, Johnny Hutchins, Adelaide Craver, Stuart Gilbert, Louis Zeller, Anne Fischer, Gwen Veazey, Bill Fisk, William Frykberg, Christian Burley, Jason Byrd, Yancey Ellis, and Richard McDaniel.

On September 6, 2006, NCWARN filed the testimony and exhibits of John O. Blackburn, Professor Emeritus of Economics at Duke University, and the testimony of William H. Schlesinger, Dean of the Nicholas School of the Environment and Earth Sciences; SACE filed the testimony and exhibits of Stephen A. Smith, Executive Director of SACE; and the Public Staff filed the testimony of John R. Hinton, a Public Utilities Financial Analyst; Thomas S. Lam, a Public Utilities Engineer; and Michael C. Maness, Supervisor of the Electric Section of the Public Staff Accounting Division. On September 7, 2006, SACE, ED, and SELC filed the joint testimony and exhibits of David A. Schlissel, a Senior Consultant, and Anna Sommer, a Research Associate, with Synapse Energy Economics, Inc. On September 11, 2006, Duke filed the rebuttal testimony and exhibit of Janice D. Hager.

On September 6, 2006, Wells Eddleman (Eddleman) filed a late petition to intervene. Duke filed an objection to Eddleman's intervention the following day, and on September 11, 2006, Eddleman filed a response to Duke's objection. In a ruling from the bench at the beginning of the evidentiary hearing in Raleigh, the Commission allowed Eddleman to intervene.

The evidentiary hearing in Raleigh began as scheduled on September 12, 2006, and continued through September 14, 2006. Duke presented the testimony of witnesses Rogers, Ruff, and McCollum and a panel consisting of witnesses Hager and Griffith. NCWARN presented the testimony of witnesses Blackburn and Schlesinger. SACE, ED, and SELC presented the joint testimony of witnesses Schlissel and Sommer, testifying as a panel. SACE presented the testimony of witness Smith. The Public Staff presented the testimony of witnesses Hinton, Lam, and Maness, testifying as a panel.

Following the hearing, briefs and proposed orders were filed by the parties on October, 13, 2006.

On October 25, 2006, Duke filed a Notice of Updated Cost Information in which the Company indicated that the estimated cost of the proposed generating facilities had increased. On November 1, 2006, the Presiding Commissioner held a conference of the parties, and on November 3, 2006, the Commission issued an order reopening the record and scheduling a second hearing in Raleigh to receive evidence concerning the appropriateness of the updated cost estimate and the cost effectiveness of the proposed facilities as compared to alternatives.

On November 9, 2006, NCWARN, SELC, ED, SACE, and NCSEA filed a motion asking for the release of non-confidential cost information relating to the Cliffside project. On November 16, 2006, Duke filed a response providing a non-confidential revised cost estimate of approximately $3.0 billion.

ELECTRIC – ELECTRIC GENERATION CERTIFICATE

On November 29, 2006, Duke filed the supplemental testimony and exhibits of witnesses Hager, McCollum, and Rogers, and the testimony and exhibits of Judah Rose, a Managing Director of ICF International. On January 8, 2007, CUCA filed the testimony of Kevin W. O'Donnell, President of Nova Energy Consultants, Inc.; ED, SACE, and SELC filed the testimony and exhibits of Douglas H. Cortez, an independent energy consultant, and the joint supplemental testimony and exhibits of witnesses Schlissel and Sommer; and the Public Staff filed the supplemental testimony and exhibits of witnesses Hinton, Lam, and Maness. On January 12, 2007, Duke filed rebuttal testimony of witnesses Hager and McCollum.

By order issued December 7, 2006, acting on motion of NCWARN, the Commission scheduled additional hearings in Charlotte and Shelby for the purpose of receiving testimony from the public concerning the issues identified in the November 3, 2006 order. This order further provided that public witness testimony would be heard at the beginning of the second evidentiary hearing in Raleigh.

The following public witnesses testified at the second Charlotte hearing: Lloyd Scher, Ronnie Bryant, Paul Woodson, Rick Roper, Veronica Waldthausen, Elizabeth Donovan, Bill Glass, Sally Kneidel, Fred Allen, Kelly Katterhagen, Mark Levine, Harry Taylor, Bob Perkowitz, Anne Jackson, Rick Bolen, Dale Brentrup, Todd Glasier, Mickey Aberman, Robert Coleman, Bernie Hargadon, Scott Lurie, Andrew Zerkle, Ivy Zerkle, Bob Thomason, Chatham Olive, Lisa Zerkle, June Lambla, Isabella Lacki, Tom Strini, Brian Staton, Tracey Crowe, Robert Perkins, Scott Spivak, Gene Stewart, Clarie Harbold, Chris Buchanan, Merrick Teichman, Greg Augspurger, and Gregg Jocoy. The following public witnesses testified at the second Shelby hearing: Walter Dalton, Tim Moore, Brownie Plaster, Chivous Bradley, Bill Frykberg, Stuart Gilbert, Bill McCarter, Robert McGahey, Barbara Land, John Brotherton, John Jackson Hunt, Victor Shaw Sarrat, Brett Keeter, Beth Henry, June Blotnick, Matt Wasson, and Yancey Ellis.

In addition to the public witnesses who testified, the Commission allowed others to submit written statements in lieu of oral testimony.

The second hearing in Raleigh began as scheduled on January 17, 2007, and continued through January 19, 2007. At the beginning of the hearing, the following public witnesses testified: Beth Kuehnert, Laura Combs, Beverly D'Aquanni, Nancy Petty, Alice Loyd, Jim Senter, David Welch, Jim Melnyk, Robert Cox, Lilian Royal, Audrey Schwankl, Andrea Vizoso, John Haebig, Marywinne Sherwood, Katie Kenlen, Barbara Janeway, Lyle Adley-Warrick, Henry Elkins, Lynice Williams, Cindy Moore, Aniko Gaal, Sally Buckner, Daniel Morris, Thomas Henkel, Maria Kingery, Helen Tart, Susan Tideman, Alison Carpenter, Chatham Olive, and Herman Jaffe.

Following the presentation of public witness testimony, Duke presented the testimony of witnesses Hager, McCollum, Rogers, and Rose, and CUCA presented the testimony of witness O'Donnell. ED, SACE, and SELC presented the testimony of witness Cortez and the joint testimony of witnesses Schlissel and Sommer. The Public Staff presented the testimony of witnesses Hinton, Lam, and Maness, testifying as a panel.

On January 26, 2007, the Presiding Commissioner issued a Notice of Receipt of Communication giving all parties notice that a communication had been received by the Commission that pertained to the testimony presented by Duke at the January 17-19, 2007 hearing and that appeared on its face to have been sent by a party to the docket. Duke made no filing in response to this notice, and the Commission finds that Duke was not prejudiced by the communication.

Following the hearing, further briefs and proposed orders were filed by the parties on February 7 and 13, 2007.

In addition to the testimony and statements of many public witnesses, the Commission has received an unprecedented number of letters and e-mails expressing intense public interest in this matter.

On February 28, 2007, the Commission issued a Notice of Decision advising the parties of its decision, to be set forth more fully in the present order.

On March 14, 2007, the Commission issued an order requesting that Duke consider disclosing approximate cost information for construction of one unit, similar to Duke's November 16, 2006 letter cited above. On March 14, 2007, Duke filed a letter authorizing the Commission to use in its order the cost estimate given by Duke witness Hager during a confidential portion of the January 19, 2007 hearing.

Based upon the foregoing, the verified application, the evidence and exhibits presented at the hearings, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. Duke is a public utility providing electric utility service to customers in its service area in North Carolina subject to the jurisdiction of the Commission.

2. The Commission has jurisdiction over this application. Pursuant to G.S. 62-110.1 and Commission Rule R8-61(b), a public utility must receive a certificate of public convenience and necessity prior to constructing electric generating facilities in North Carolina.

3. G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. The Commission must consider many factors, including the present and future needs for power in the area; the extent, size, mix, and location of the utility's existing plants; arrangements for pooling or purchasing power; and the construction and fuel costs of the project and of alternatives, before granting a certificate of public convenience and necessity for a new generating facility.

4. Duke filed an application on June 2, 2006, seeking a certificate of public convenience and necessity for the construction of two 800-MW supercritical pulverized coal (SCPC) units, together with certain related transmission facilities, at the site of the existing Cliffside

Steam Station on the border of Cleveland and Rutherford Counties (the Cliffside project), to provide baseload capacity, with the first unit to begin commercial operation by 2011. As part of the project, Duke plans to retire existing Cliffside Units 1 through 4, which total 198 MW.

5. Duke tested various long-range resource portfolio options against a range of sensitivities and scenarios in connection with its 2005 and 2006 Annual Plans and in an updated analysis prompted by the increased costs indicated in the October 25, 2006 Notice of Updated Cost Information. Duke concluded that the Balanced Cliffside portfolio, the portfolio upon which the application is based, performed well under varying sensitivities and that the Cliffside project is the Company's best option at this time.

6. Duke's 2005 and 2006 Annual Plans filed with the Commission in Docket Nos. E-100, Sub 103 and Sub 109, show substantial load growth and the need for capacity additions over the next 15 years. However, during the pendency of this proceeding, Duke's need for additional generating capacity in the 2011-12 time frame, as reflected in its 2005 and 2006 Annual Plans, decreased from 3400 MW to 2120 MW. The 2120 MW figure includes a need for 800 MW of coal-fired baseload capacity.

7. At the second hearing in this proceeding, Duke revealed that it is considering the sale of up to 800 MW of the proposed two-unit, 1600-MW Cliffside project.

8. Duke has not carried its burden of proof to show that it needs 1600 MW of baseload generating capacity in the 2011-12 time frame. Duke does need 800 MW of baseload generating capacity beginning in 2011.

9. Duke has initiated a process of collaborative workshops with various stakeholders, including customers and other interested persons, and these collaboratives are expected to provide recommendations for new demand side management (DSM) programs by the middle of 2007.

10. Duke has committed to invest, on an annual basis, 1% of its annual retail revenues from the sale of electricity in energy efficiency and demand side programs, subject to completion of the ongoing collaborative workshops with stakeholders and subject to such appropriate regulatory treatment for the costs associated with those programs as the Commission may determine to be just and reasonable. Duke has further committed to retire older coal-fired generating units (in addition to Cliffside Units 1 through 4) on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from these new programs, up to the MW level added by the Cliffside project as certificated by the Commission.

11. Cost-effective DSM programs and reliance upon renewable energy resources are both in order; however, Duke cannot rely upon DSM and renewables to eliminate or delay its need for additional baseload generating capacity beginning in 2011.

12. Duke cannot rely upon new nuclear generating facilities to supply its need for additional baseload generating capacity beginning in 2011.

13. Duke cannot rely upon integrated gasification combined cycle (IGCC) technology, a new and emerging coal-fired generation technology, to supply its need for additional baseload generating capacity beginning in 2011.

14. Natural gas-fired combined cycle (CC) generation is the only viable generation alternative to SCPC generation for supplying Duke's additional baseload generating capacity needs beginning in 2011.

15. It is unreasonable for Duke to rely upon natural gas-fired CC generation to supply all of its additional baseload generating capacity needs beginning in 2011.

16. The construction of one 800-MW SCPC unit at Cliffside and the retirement of Cliffside Units 1 through 4 will make for a more diverse and secure generation fleet and will allow Duke to increase its baseload generating capacity without significantly increasing its environmental footprint.

17. Duke appropriately conducted a comprehensive siting process to select the existing Cliffside Steam Station as the site for the additional baseload generation that it needs.

18. Duke has estimated the construction cost of one 800-MW unit at Cliffside. The Commission approves this estimate subject to the reporting requirements ordered herein.

19. The public convenience and necessity require the construction of one 800-MW SCPC generating unit, together with related transmission facilities, at the site of the existing Cliffside Steam Station, conditioned upon the retirement of existing Cliffside Units 1 through 4 and conditioned upon Duke's commitment to invest 1% of annual retail electricity revenues in energy efficiency and demand side programs and to retire older coal-fired generating units (in addition to Cliffside Units 1 through 4) on a MW-for-MW basis, considering the impact on reliability, for actual load reductions realized from these new programs up to the MW level added by the Cliffside unit. As a result, Duke is hereby granted a certificate of public convenience and necessity pursuant to G.S. 62-110.1 authorizing construction of one 800-MW SCPC generating unit subject to the conditions enumerated above.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence in support of these findings of fact is found in the certificate application for the Cliffside project, the testimony and exhibits in this docket, and the statutes and rules governing the authority and jurisdiction of the Commission. These findings are informational, procedural, and jurisdictional in nature.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

This finding of fact is based upon the statutes and case law of North Carolina.

The ED/NCSEA/NCWARN/SACE/SELC brief argues that the Commission must consider the issues of need and cost. The Commission's mandate in this proceeding is broader than that. G.S. 62-2(a)(3) and (3a) declare it policies of the State, among others, to promote adequate, reliable, and economical utility service and to require energy planning "to result in the least cost mix of generation and demand-reduction measures which is achievable..." The Utilities Commission is given authority to regulate public utilities in accordance with these policies. G.S. 62-110.1(a) provides that no public utility shall begin the construction of any electric generating facility to be directly or indirectly used for furnishing public utility service without first obtaining a certificate of public convenience and necessity from the Commission. G.S. 62-110.1(c) requires the Commission to develop and keep current an analysis of the long-range needs for expansion of electric generating facilities in the State and to "consider such analysis in acting upon any petition by any utility for construction."

G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. State ex rel. Utilities Comm. v. Empire Power Co., 112 NCApp 265, 278 (1993), disc. rev. denied, 335 NC 564 (1994); State ex rel. Utilities Comm. v. High Rock Lake Ass'n, 37 NCApp 138, 141, disc. rev. denied, 295 NC 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. Empire, 112 NCApp at 279-80; High Rock Lake, 37 NCApp at 140. Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. State ex rel. Utilities Comm. v. Casey, 245 NC 297, 302 (1957). "[Chapter 780 of the 1975 Session Laws], codified as G.S. 62-110.1(c)-(f), directs the Utilities Commission to consider the present and future needs for power in the area, the extent, size, mix and location of the utility's plants, arrangements for pooling or purchasing power, and the construction costs of the project before granting a certificate of public convenience and necessity for a new facility." High Rock Lake, 37 NCApp at 140-1.

As hereinafter discussed in this order, the Commission has considered all of these factors -- need, the size and mix of existing plants, pooling, purchases, DSM, alternative technologies including renewables, fuel costs, and construction costs -- in determining whether the public convenience and necessity are served by Duke's proposal in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4 AND 5

The evidence supporting these findings of fact is contained in the testimony and exhibits of Duke witnesses Rogers, Rose, McCollum, Griffith, and Hager and Public Staff witnesses Maness and Hinton.

Duke offered considerable testimony as to the process used to determine that it is appropriate to add baseload capacity in the 2011-12 time frame and that the Cliffside project is the best option. Witness Hager testified that the Company develops and files an annual resource plan based upon a 15-year forecast and a target reserve margin of 17%. The decision to pursue the Cliffside project was one component of the action plan resulting from the 2005 planning process. In the 2005 Annual Plan, Duke identified potential supply-side resources and performed an economic screening process. The technologies that passed all of the screens in 2005 were combustion turbine, coal, combined cycle, and nuclear. Renewable technologies were tested, but did not pass the screening. Using the initial screening results, Duke developed resource portfolios that were tested under baseline assumptions and then subjected to analysis of their sensitivity to factors such as changes in fuel costs, load growth, and climate change policy. The results showed that a combination of new peaking, intermediate, and baseload generation, as well as DSM resources, is needed over the next 15 years. The generation portfolios including 1600 MW of baseload coal capacity consistently outperformed alternative portfolios during Duke's initial analysis.

Duke witness Griffith offered a more detailed explanation of the process at the September 2006 hearing. He testified that the process consisted of two sub-processes, a screening process and a more detailed portfolio analysis. The screening process examines the economics of a wide range of resource alternatives, using such tools as a busbar screening curve. The screening assists in developing specific portfolio strategies that can be analyzed further. Witness Griffith testified that his firm, Global Energy, determined a series of portfolio strategies that could then be analyzed in more detail in the portfolio analysis process. Global Energy used its Capacity Expansion Model (CEM), which evaluates the economics of every possible combination of resources available and identifies the lowest cost strategy given the future envisioned by the scenario or sensitivity case. The CEM produced ten alternative resource portfolios. These portfolios were then analyzed using the Planning and Risk (PAR) simulation model. The PAR model, which is more detailed than the CEM, analyzed all ten portfolios under baseline assumptions. Six portfolios were then chosen and subjected to sensitivity analyses. According to witness Griffith, the PAR model clearly indicated that a portfolio with 1600 MW of coal generation was dominant in the base case and in the majority of the sensitivity analyses.

The six portfolios, which have been analyzed in one form or another since the 2005 planning process, are as follows:

(1) Balanced Cliffside -- coal (1600 MW), nuclear (1734 MW), combustion turbines (2771 MW), and retirement of Cliffside Units 1-4;

(2) Balanced Single Unit Cliffside -- coal (800 MW), nuclear (1734 MW), combined cycle (585 MW), combustion turbines (2990 MW), and retirement of Cliffside Units 1-4;

(3) Balanced Cliffside with Retirements -- coal (1600 MW), nuclear (1734 MW), combustion turbines (3345 MW), retirement of Cliffside Units 1-4, and retirement of 577 MW of older coal capacity;

(4) All Gas and Nuclear -- nuclear (1734 MW), combined cycle (1170 MW), and combustion turbines (3010 MW);

(5) All Gas -- combined cycle (2925 MW) and combustion turbines (2990 MW); and

(6) Cliffside and Gas -- coal (1600 MW), combined cycle (1755 MW), combustion turbines (2756 MW), and retirement of Cliffside Units 1-4.

At the September 2006 hearing, Duke and Public Staff witnesses concluded that the Cliffside project, which is based upon the Balanced Cliffside portfolio, is the best option given the needs of Duke customers. Subsequent to the September 2006 hearing and the cost increases that Duke reported to the Commission, witness Hager updated the cost data for all of the supply-side alternatives considered in the screening process in the 2006 Annual Plan and performed additional analysis to determine if the Cliffside project remained the best choice. The portfolios evaluated in the updated analysis were the same as those evaluated in the 2006 Plan with the addition of a seventh portfolio that considered a sale of 800 MW of the Cliffside project to a third party. The new Balanced Cliffside Shared Ownership portfolio included coal (1600 MW with 800 MW owned by an outside entity), nuclear (1734 MW), combined cycle (585 MW), combustion turbines (2990 MW), and retirement of Cliffside Units 1-4.[1]

The result of Duke's updated analysis was that the All Gas and Nuclear portfolio had the lowest present value revenue requirements (PVRR) under base assumptions over a 35-year study period. The Balanced Cliffside portfolio was second. The difference in PVRR between the top two portfolios would result in average rates less than 0.3% higher each year over the study period. However, the Balanced Cliffside portfolio was robust under various key sensitivities, including high gas prices, high load, high gas and coal prices, CO_2 tax and high gas prices, and high gas and coal prices coupled with a 20% increase in nuclear capital costs. At the January 2007 hearing, Hager stated that the Cliffside project provides a balance of reliability, timeliness, and cost-effectiveness. The Public Staff witnesses also continued to support the Cliffside project.

The Commission concludes that it was appropriate for Duke to conduct the long-range computer analyses of various supply-side resource options, and the Commission has considered these in its deliberations herein. The matter presently before the Commission is the application for the Cliffside project. The Commission cannot commit, and is not called upon to commit, to a complete portfolio of new construction running years into the future. The Commission must take from these analyses the information that is helpful in making the present decision as to whether the public convenience and necessity are served by Duke's application for a certificate for the Cliffside project. It is appropriate for the Commission to consider many factors in making this decision, including the overall integrated resource plan of the utility, but the Commission is not bound by the results of any single least-cost computer study.

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

The evidence supporting these findings of fact is contained in Duke's 2005 and 2006 Annual Plans and in the testimony and exhibits of Company witnesses Rogers, Ruff, and Hager; Public Staff witness Hinton; and SACE/ED/SELC witnesses Schlissel and Sommer.

At the September 2006 hearing, Duke witness Rogers testified that the Company's most important overall objective is to ensure that its customers have access to reliable and reasonably priced electricity to meet their needs. Achievement of this objective enables businesses to feel secure in locating and maintaining facilities in North Carolina, fosters economic growth, and contributes to the quality of life for all citizens of the State.

Duke witness Ruff testified that the Company's 2005 Annual Plan "demonstrates the need for 3400 additional MW of capacity in 2011, which increases to 4360 MW in 2014." She stated that Duke performed a least-cost study of potential supply-side and demand-side resources and "determined that new coal capacity is the best option for meeting the earliest baseload

[1] Note that the two portfolios that add 800 MW at Cliffside, the Balanced Single Unit and the Shared Ownership, both include retirement of Cliffside Units 1-4, leaving a net of 600 MW gained at Cliffside. Duke's remaining needs are obviously satisfied by the other generation included in these portfolios.

generation needs." She further stated that this new coal capacity should be in the form of two 800-MW units at Duke's existing Cliffside plant, with the first unit on line in 2011.

Witness Hager testified that Duke's annual planning process begins with a 15-year forecast of the Company's peak demands and energy sales. She noted that Duke's average annual load growth is between 300 MW and 400 MW. Duke is adding about 40,000 to 60,000 new customers each year and, in addition, needs to replace certain existing purchase power agreements that expire during the planning horizon. Hager also testified that the 2005 Annual Plan indicated a need for 3400 MW of cumulative resource additions by 2011 and that approximately 2841 MW of these additions would be peaking capacity and 800 MW would be baseload capacity. In Duke's 2006 Annual Plan, which was prepared after Duke's initial testimony herein was filed, the comparable need by year 2011 is 2120 MW. The change from the 2005 Plan is largely attributable to Duke's purchase of the 825-MW Rockingham generating facility and the decision by Energy United, an electric membership cooperative, not to enter into a power purchase agreement with Duke. Witness Hager testified that, under Duke's 2006 Annual Plan, the 2120 MW need would be satisfied by 64 MW of additional nuclear capacity at the Catawba plant, two 564-MW gas combustion turbine or combined cycle units, and 800 MW of coal capacity. She testified that the second 800-MW Cliffside unit in 2012 achieves a reserve margin of at least 17%.

Public Staff witness Hinton testified that he believes the peak load and energy sales forecasts contained in Duke's 2005 and 2006 Annual Plans are reasonable.

SACE/ED/SELC witnesses Schlissel and Sommer testified that Duke has not adequately demonstrated a need for 1600 MW of baseload capacity in 2011. They maintained that, at most, Duke has demonstrated that additional capacity is needed in the peak summer hours and that the high reserve margins in the 2005 Annual Plan for winter peak hours suggest that Duke does not need any baseload capacity until 2013. Witness Schlissel testified that Duke's failure to present evidence concerning its load duration curve, together with the lack of evidence that the Company fully investigated buying capacity from other utilities, leaves doubt as to whether there is a need for the additional baseload capacity. He argued that Duke should have looked at a wider range of alternatives -- not just coal, natural gas, and nuclear -- and should have also considered a range of energy efficiency programs, renewable technologies, and purchases from the market. He opined that, if Duke had adopted this approach, it might well have projected a need for peaking capacity in 2011, rather than baseload capacity.

At the January 2007 hearing, Duke introduced for the first time the possibility of selling up to half of the proposed 1600-MW capacity of the Cliffside project. Witness Hager presented an analysis of a Shared Ownership portfolio. She testified that partial ownership almost always outperforms full ownership, that the Shared Ownership portfolio achieves savings over the Single Unit portfolio because there are substantial economies of scale in building both units, and that "the Company will pursue a partial sale of up to 50% of the Cliffside Project if it is determined that such a sale will improve the economics for the Company and its customers." Hager denied that consideration of such a sale reveals a lack of need for the full 1600 MW as proposed. She testified, "It's just a matter of which units get dispatched when and at what rate" and, "If we have it, it has benefits." In the event of such a sale, an additional 585 MW of intermediate gas-fired combined cycle capacity would be added to the Duke system in addition to the new coal-fired capacity.

Witness Rogers testified, "I'm open to doing [the Cliffside project] with a partner and building a regional plant." He presented shared ownership as a matter of "good business sense to explore spreading those costs, risks, and benefits among more than one electric provider in the region." Duke customers would receive "a 'volume' discount – 800 or so MW, built at the lower 1600 MW cost."

Duke and the Public Staff both argue that Duke's 2005 and 2006 Annual Plans demonstrate the need for a substantial amount of additional supply-side capacity beginning in the 2011-12 time frame, and that the plans support granting a certificate for the Cliffside project; however, the Commission is not convinced that these plans establish a need for the entire project. Duke's certificate application filed on June 2, 2006, was based upon the projected load requirements in Duke's 2005 Annual Plan. The application states that "the need for the Cliffside Project is demonstrated in Duke Energy Carolinas' 2005 Annual Plan filed with the Commission on November 1, 2005, in Docket No. E-100, Sub 103....Duke Energy Carolinas' 2005 Annual Plan identifies the need for an additional 3,400 MW of new resources to meet customers' energy needs by 2011 and 3,810 MW by 2012." Although the 2005 plan projected a need for an additional 3400 MW from 2007 through 2011, a large portion of this additional 3400 MW was to accommodate four anticipated wholesale contracts with North Carolina cooperatives, which were expected to begin in September 2006 and continue through 2021. Shortly after the filing of the Cliffside application, Duke filed its 2006 Annual Plan in Docket No. E-100, Sub 109, on September 1, 2006 (corrected on September 11 and updated on October 31). In its 2006 plan, Duke states that only three of the four cooperatives decided to sign wholesale contracts with Duke. Duke's 2006 plan projected that additional load from 2007 through 2011 had declined from the 3400 MW figure cited in the 2005 plan to 2120 MW, a significant reduction of 1280 MW.

At the first evidentiary hearing in September 2006, some Duke witnesses continued to cite the 3400 MW figure, even though the 2006 plan had been filed by that time. Duke witness Hager acknowledged the reduction reflected in the 2006 plan and explained that the reduction resulted primarily from Duke's purchase of the Rockingham Power, LLC, plant, which has a capacity of about 825 MW, and the decision of the fourth cooperative not to enter into a wholesale contract with Duke. This fourth contract, which did not materialize, had been expected to involve about 500 MW. Hager testified that the 2120 MW figure set forth in the 2006 plan represents the amount of capacity beyond existing generation (including Rockingham) and existing and projected DSM needed to meet a 17% reserve margin. She explained that the 2120 MW of projected need would be satisfied by 64 MW of additional nuclear capacity at the Catawba plant, two 564-MW combustion turbines or combined cycle units, and 800 MW of coal capacity. When asked to justify the proposed 1600 MW of coal capacity from Cliffside, Hager testified that adding the second Cliffside unit in 2012 would raise the reserve margin, which was projected as 16.3% in 2011, to 18.5% in 2012.

For purposes of this proceeding, the Commission accepts the 2120 MW need projected in Duke's 2006 plan, but the projections in the 2006 plan make, at best, a weak case for the full

Cliffside project. They show a need for only 800 MW of coal-fired baseload capacity in 2011. While the projected reserve margin falls below the 17% goal in 2011, it is only slightly below. The reserve margin would fall further in subsequent years, but only if nothing else were done. In fact, there are many options besides a second Cliffside unit for making up the difference and regaining the desired reserve margin. For example, construction of intermediate gas-fired combined cycle capacity could be moved up (which is what Duke proposes to do in the event that ownership of Cliffside is shared). Other options include purchases (Hager testified that Duke is always looking for purchase opportunities), and renewables (Rogers testified to a probability that a renewable portfolio standard will be enacted into law).

The case for certification of a second Cliffside unit was weakened further during the second hearing in January 2007 by the introduction, for the first time, of the possibility that Duke might sell up to 800 MW of the proposed Cliffside capacity. Under the Shared Ownership portfolio that Duke presented, up to one-half of the proposed capacity would be owned by another company and used for that other company's purposes; there would be no buyback by Duke.

Several reasons were given in support of a sale. One was the economies of scale realized from building both units: Duke customers would get a "volume discount," 800 MW built at a lower per/MW cost. Hager testified that these economies of scale were significant; however, a similar argument could be made for almost any construction project. Economies of scale, in and of themselves, do not establish a need for the capacity, and the need for the capacity is the Commission's initial consideration under G.S. 62-110.1.

Other reasons in support of a sale were the sharing of risks and the regional approach to building generation suggested by witness Rogers. The record is simply insufficient for the Commission to rely upon these arguments for two reasons. First, G.S. 62-111(d) provides that no person shall obtain a "franchise" for the purpose of transferring it to another. A "franchise" includes certificates. G.S. 62-3(11). G.S. 62-110.1 does not envision the Commission granting a certificate for a second Cliffside unit with the knowledge or expectation that Duke will promptly sell it. Second, although G.S. 62-110.1(d) speaks to "pooling of plant," shared ownership is not the basis upon which Duke filed its application herein, and there is no evidence of any regional or joint need that such shared ownership would serve.

Witness Hager was asked at the hearing whether Duke's consideration of a sale demonstrates that the second Cliffside unit is not needed. In response, she discussed the dispatch of plant and explained, "If we own the full 1600, think about [sic] everything else drops a certain percentage in terms of its capacity factors. If we only own 800, they drop a little less....If we have it, it has benefits." The Commission is not convinced that a level of improved dispatch that Duke can either take or manage without is enough to meet the standard of public convenience and necessity.

The Public Staff argues in its brief that the Commission should not consider a possible sale because "such a transaction would be subject to separate review by the Commission" in the future. However, the Commission does not believe that it can determine whether a second 800-MW unit is required by the public convenience and necessity without knowing who would own the second unit, what need would be served, and how the costs of operation would be allocated. The Public Staff would leave such matters to a subsequent proceeding, but the Commission believes that these matters are essential considerations under G.S. 62-110.1 that must be resolved in this proceeding in order for a certificate to be granted.

The Attorney General contends in his brief that the evidence of a possible sale shows that Duke has not demonstrated a need for the second 800-MW Cliffside unit. "If Duke is prepared to sell half of the proposed 1600 MW, then it must not need that capacity." Relying heavily on this contention, the Attorney General urges the Commission to grant a certificate for only one Cliffside unit at this time. The Commission agrees.

Given the baseload capacity needs shown in Duke's 2006 Annual Plan, given Duke's consideration of selling up to half of the proposed Cliffside capacity, and given uncertainty over the ownership and use of a second 800-MW unit, the Commission concludes that Duke has not shown a need for a second 800-MW unit sufficient for present purposes. In summary, the Commission concludes that Duke has not carried its burden of proof to show that it needs 1600 MW of baseload generating capacity in the 2011-12 time frame. Duke has shown that it needs 800 MW of baseload generating capacity beginning in 2011.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9-11

The evidence supporting these findings of fact is found in the testimony of Duke witnesses Rogers and Hager; SACE/ED/SELC witnesses Schlissel and Sommer; Public Staff witnesses Lam, Maness, and Hinton; NCWARN witness Blackburn; and SACE witness Smith.

Duke witness Hager testified to Duke's commitment to DSM, which includes both demand response and energy efficiency. The existing demand response programs include time-of-use programs and interruptible programs, and these programs are believed to have reduced the summer 2006 peak by 766 MW. The existing energy efficiency programs include Energy Star, which promotes more energy efficient homes; a loan program to encourage increased energy efficiency in existing homes; and a comparable loan program for low-income customers.

Hager stated that the only new DSM programs included in the 2005 Annual Plan were 100 MW of new demand response programs. In its 2006 Annual Plan, Duke added 101 MW of new energy efficiency programs, which, Hager testified, is indicative of what can be achieved by future cost-effective energy efficiency programs. The total amount of new DSM in the 2006 plan was therefore 201 MW. She testified that the Company did not include any additional DSM in its recent, updated analyses because it had no new information. However, she stated that Duke is currently participating in collaborative workshops with various stakeholders to develop new DSM programs, and it is thought that the results from those sessions will be available in mid-2007. Hager is hopeful that these DSM collaborative workshops will produce new information to incorporate into the 2007 modeling. Stakeholders involved in these collaboratives include, among others, Environmental Defense, Lowe's Home Center, Food Lion, the University of North Carolina, the North Carolina Housing Authority, the State Energy Office, the Attorney General, and the Public Staff.

Hager noted that, while there has been much discussion about the potential for additional energy efficiency programs, no one has proposed a set of programs that Duke could run on its system, and she asserted that the Company cannot ignore forecasted demand in favor of speculation regarding the ability of DSM to reduce some of the need. Hager was cross-examined about the suggestion in the December 2006 GDS Associates study[1] that North Carolina could reduce its electric energy use by 14% by 2017 through energy efficiency programs. She expressed skepticism that such results could, in fact, be achieved on Duke's system, and she stated that the study depends on certain simplifying assumptions that may not be appropriate. She testified that, regardless of what the GDS report may say, one cannot reasonably assume that there will be sufficient energy efficiency available to offset the proposed Cliffside units in the time frame when they will be needed.

With respect to renewable generation, witness Hager referred to the December 2006 report of La Capra Associates on the feasibility of a renewable portfolio standard in North Carolina,[2] and she noted that Jonathan Winer of La Capra has been quoted as saying that, even if a renewable portfolio standard were adopted, the coal plants now being planned would likely still be needed. Witness Hager testified that installation of a MW of renewable generation does not automatically eliminate the need for a MW of conventional generation and that, if all the renewable generation contemplated by the La Capra study is installed, there might be 1000 MW of renewable generation added to Duke's system but only about 300 or so MW of conventional generation displaced.

SACE/ED/SELC witnesses Schlissel and Sommer asserted that the efficiency programs outlined in Duke's 2005 Annual Plan are woefully inadequate compared to energy efficiency programs across the nation. Witness Schlissel testified that an aggressive energy efficiency program would mimic the results of the low-load scenario used in Duke's cost studies, a scenario in which gas-fired generation costs less than coal. Witness Sommer testified that the low-load scenario is achievable if one were to apply an aggressive energy efficiency program as discussed in the GDS study. She testified that the GDS study's goal of a 14% reduction by 2017 from energy efficiency measures was conservative and that the potential might be higher. Witness Schlissel stated that energy efficiency programs are more comparable to a baseload resource and that new energy efficiency programs would displace baseload capacity. He testified that adding 1600 MW of baseload capacity through construction of the Cliffside project would lessen Duke's incentive to increase the use of energy efficiency and that Duke should re-run its cost studies to reflect energy efficiency portfolios based on the GDS report.

Witnesses Schlissel and Sommer also described ways in which they believe that Duke's implementation of the CEM model was flawed. First, they stated that Duke should have used a different programming mode in its CEM modeling. Duke operated the CEM model in a programming mode which does not require the addition of capacity in the discrete amounts that would normally be built. Running the CEM model in a different mode would produce different

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[1] A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina, GDS Associates, Inc., December 2006.

[2] Analysis of a Renewable Portfolio Standard for the State of North Carolina, La Capra Associates, December 2006.

results and might add less capacity than the runs presented by Duke. Second, the witnesses testified that Duke eliminated all but fossil and nuclear options in its busbar screening analysis. Alternative options were never passed to the CEM for analysis and could not be selected. Alternative options include DSM and renewable options, which, according to the witnesses, could have been analyzed by the CEM and which might have been attractive as hedges against the uncertainties of future fuel prices, capital costs, and greenhouse gas regulation.

They also testified that Duke should have considered biomass and wind power as alternatives to coal, citing a July 2004 report by the North Carolina Solar Center finding that biomass is a commercially proven and viable option for North Carolina. Additionally, they stated that they have seen estimates of the potential for perhaps 1700 to 2000 MW of biomass generation in North Carolina and that actual experience and studies have shown that wind power can reduce the need for other capacity and provide low-cost energy.

Witnesses Schlissel and Sommer testified at the January 2007 hearing that they had not had sufficient time to fully review Duke's updated quantitative analysis results, but that, even after a relatively brief review, the updated results do not support the addition of the Cliffside project in 2011-12. In the updated analysis, the CEM generally added less coal capacity. However, due to time constraints, Duke simply used the portfolios analyzed in the original 2006 analysis to evaluate the impact of the updated Cliffside costs, rather than using the results of the new CEM runs to develop new resource portfolios. There is, therefore, a "disconnect" between the updated CEM results and the portfolios used in the updated PAR analysis.

Responding to witnesses Schlissel and Sommer, witness Hager testified that she believes it is inappropriate to compare DSM to supply-side resources using screening curves; use of a detailed production model is necessary to capture the interactions between such different resource options. She stated that there was not enough information available on the details of potential DSM programs to include them in the CEM as a flexible resource, but that Duke hoped to do so in the future as a result of the work of the collaboratives. For purposes of the 2006 analysis, Duke included a level of DSM resources that it considers indicative of what can be achieved. She does not believe that there will be enough DSM to offset the need for the Cliffside project, and the risk of delay until more data is available is too great. Additionally, witness Hager testified that the low-load scenario contains a greater reduction in load than the energy efficiency savings shown in the La Capra study.

Witness Hager testified that Duke prefers to run the CEM model in the mode that identifies exactly the various types of capacity needed in each time period. The CEM analysis is still a high-level screening process, not as rigorous as the more detailed analysis that the Company then proceeds to perform. The Company uses the results of each run, or perhaps several CEM runs, to create possible portfolios with reasonable sizes and construction dates.

Witness Hager disagreed with Schlissel and Sommer's conclusion that the updated CEM runs do not support the Cliffside project. She indicated that the updated CEM results, set forth in Table 1 of Schlissel and Sommer's testimony, included outcomes with various amounts of new coal capacity being added, and some of the new CEM runs show coal capacity being added in 2011. She testified that the portfolios evaluated by the updated PAR were appropriate to help management decide whether to proceed with the Cliffside project and that additional analysis was unnecessary.

With respect to wind and biomass, Duke witness Hager testified that the Company included 75 MW of wind power in its 2005 analysis and 100 MW each of wind and biomass in its 2006 analysis. She stated that Duke's analysis is focused on which resource technologies will result in the least cost being charged to its customers. She indicated that, to the extent renewable technologies can provide power on a least-cost basis, they will be included in Duke's portfolio of resources.

Duke witness Rogers is co-chair of the National Action Plan for Energy Efficiency. He testified that DSM is a useful tool, but that DSM alone cannot completely address increased load demand and that energy efficiency programs cannot offset the need for the Cliffside project. Although other states provide examples of new DSM programs that may help improve energy efficiency in North Carolina, one cannot accurately predict how well programs will transfer from one state to another. Rogers testified that he has created a special group to focus on building energy efficiency programs in all of the states where Duke Energy operates. Rogers stated that, when a utility decides to reinvigorate its DSM process, three to five years may be required before the process "gets rolling." Furthermore, after a specific energy efficiency program is implemented, one or two years are required in order to determine by how much the program has reduced customer demand. There is, too, a point of diminishing returns with investments in DSM; in other words, there is a point at which increasing the amount of money devoted to such programs becomes inefficient and impractical.

Duke committed $2 million to conservation and customer education programs as part of its merger with Cinergy Corporation. Witness Rogers testified that, subject to completion of the Company's ongoing collaborative process to develop new energy efficiency programs and subject to appropriate regulatory treatment of the Company's energy efficiency investments, Duke is now willing to commit to invest 1% of its annual revenues in energy efficiency programs. He stated that 1% of annual revenues is approximately $50 million. Witness Rogers further testified that, upon commercial operation of the Cliffside project and subject to appropriate regulatory approvals and in the absence of compelling customer or system reliability needs, Duke will retire generation from its older, less efficient coal units on a MW-per-MW basis for every MW saved by new energy efficiency programs up to the level added by the Cliffside project. Rogers testified that "in the event that we end up with only one unit, [the commitment to retire older coal plants based on energy efficiency gains] would be contingent on that 800 megawatt, tied to that 800 number." Rogers explained that such new programs would include both demand response and energy efficiency programs. With respect to what constitutes "appropriate regulatory treatment," he proposed that the Commission take a fresh look at incentives for energy efficiency and come up with a more modern approach; however, he agreed that Duke will accept whatever treatment the Commission decides to be appropriate. Witness Rogers stated that Duke is "not tying [the commitment to invest in energy efficiency programs] to approval of the Cliffside Project but we thought it was important in the context of rolling out – where Cliffside is the central part of our plan to also show the Commission that we have other parts of our plan."

Rogers agreed that, should renewable portfolio standard legislation with energy efficiency language come from Congress or the North Carolina legislature, he would be willing to discuss that statute with third parties.

Public Staff witnesses Lam, Maness, and Hinton testified that many of the DSM options suggested by intervenors are not cost-effective. The Public Staff contacted commission staffs in other states to compare Duke's DSM programs to others, and the Public Staff believes that the ongoing DSM collaboratives will be useful.

NCWARN witness Blackburn suggested that a more detailed study of energy efficiency programs is needed. He estimated that Duke could save six to seven billion kilowatthours of electricity from residential sales over the next ten years. Witness Blackburn maintained that Duke's failure to consider any conservation or energy efficiency programs that might cause non-participating customers to pay higher rates was inappropriate.

SACE witness Smith testified that Duke has not done an adequate job of aggressively pursuing energy efficiency. He stated that Duke does not have to build a new plant immediately since it has a 17% reserve margin, and that the Commission should deny the application and instruct Duke to give greater weight to energy efficiency and renewable resources. He did not rule out other resources, but stated that Duke should fully exploit DSM and renewables first.

The Commission has carefully considered the evidence as to the role of DSM and renewables in the present docket. The Commission recognizes that the approval of new programs and the appropriate regulatory treatment of costs are matters to be decided in other proceedings. The matters at issue in this proceeding are whether more aggressive DSM programs and greater reliance on renewable sources of generation could delay or replace the Cliffside project and whether Duke has properly analyzed and pursued the true potential of DSM and renewables in planning the Cliffside project.

Some parties have raised questions as to the timeliness and thoroughness of Duke's DSM analyses, especially in light of the Commission's August 31, 2006 order in Docket No. E-100, Sub 103, requiring electric utilities to file "a comprehensive analysis of their DSM plans, activities, and relevant cost/benefit information" as part of, or as a supplement to, their 2006 plans. Some parties have raised even more fundamental questions as to the propriety of Duke's cost modeling techniques. The ED/NCSEA/NCWARN/SACE/SELC brief argues that Duke improperly screened out energy efficiency and renewables from further analysis by assuming levels much lower than their true potential; that Duke should have used the CEM model in a different programming mode, in which case it might have chosen less coal; and that Duke failed to carry forward its latest CEM runs, which also chose less coal, to the latest PAR analysis. The Attorney General's brief questions why Duke found the expertise and resources to conduct three comprehensive analyses of generation portfolios, but not even one analysis of specific, new DSM programs. Duke cites its collaboratives as its means of complying with G.S. 62-2(a)(3a), but the Attorney General views these as too little and too late since construction of baseload generation is being proposed.

The Commission shares certain of these questions and concerns. Duke's estimates in its 2006 plan of an additional 100 MW of demand-response and an additional 101 MW of energy efficiency seem to have been essentially placeholders. The Commission believes that Duke may well be able to accomplish substantially more than these levels – especially in light of the fact that Duke's chief executive officer has taken an aggressive, national leadership position in support of energy efficiency. Despite the Commission's concerns as to Duke's DSM analysis, the Commission cannot conclude that the weaknesses suggested by the intervenors are sufficient to justify a delay while new cost studies are required. Duke witnesses indicated that, while Duke has not negotiated firm contracts for components to be used in the Cliffside units, it has reached preliminary arrangements whereby it has been given a "place in the queue" of utilities shopping for equipment. If Duke has to perform new studies while its application is denied or held in abeyance, it would likely lose its place in the vendors' queues. The result could well be higher costs and delays resulting in later completion dates if the units are ultimately approved. Later completion dates create a risk that insufficient generation will be in place when needed and at its present estimated cost. Complex studies are never perfect, and they can always be improved. The Commission acknowledges that revised cost studies could provide valuable new information; however, given the circumstances of this case, the Commission does not believe that the benefits to be gained from requiring Duke to redo its studies outweigh the possible delays and cost increases resulting from the loss of Duke's preliminary arrangements with vendors. Thus, on the present record, the Commission concludes that Duke cannot rely upon either DSM measures or additional renewable generation in the short term to eliminate or delay construction of additional supply-side resources.

Although the Commission does not believe that cost-effective DSM and renewables can eliminate or delay Duke's need for additional baseload generating capacity in 2011, the Commission does believe that the public convenience and necessity require Duke to take reasonable and cost effective, but aggressive, steps to reduce demand and to retire its older, less efficient coal plants. The granting of the certificate for the Cliffside project must, in the Commission's view, be tied to implementation of energy efficiency and demand side programs that will allow Duke to realize sufficient MW savings to retire its older, less efficient coal plants as rapidly as reasonably practicable, as witness Rogers committed in his testimony. Accordingly, the Commission will require Duke to honor its commitment to invest, on an annual basis, 1% of its annual retail revenues from the sale of electricity in energy efficiency and demand side programs, subject to the ongoing collaborative workshops and subject to Commission approval and to such appropriate regulatory treatment as the Commission may determine to be just and reasonable, and to retire older coal-fired generating units on a MW-for-MW basis, considering the impact on the reliability of the entire system, to account for actual load reductions realized from these new programs, up to the MW level added by the Cliffside unit certificated by this order. Duke will be required to submit a comprehensive plan for verifying MW savings from new energy efficiency programs and identifying the exact number of MW and the specific coal units to be retired pursuant to this commitment.

The Commission is eager for the uncertainty regarding the future of DSM to be resolved. The Commission is pleased with Duke's commitment to dramatically increase investment in cost effective energy efficiency and demand side programs in North Carolina, and the Commission urges Duke to pursue its collaboratives to a prompt and productive conclusion. With Duke CEO

Rogers providing the leadership and with the stakeholder collaboratives providing the process, the Commission fully expects that Duke will have more meaningful data in its future filings and that Duke will achieve greater levels of DSM savings than those factored into its recent plans. The Commission believes that, for present purposes, the best approach is to act on the basis of the present record, to encourage Duke to pursue its stakeholder collaboratives, and to require that Duke adhere to its commitment to invest 1% of annual retail electricity revenues in energy efficiency and demand side programs and to match load reductions on a MW-for-MW basis with retirements of its older coal-fired generating units.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the testimony of Duke witness Rogers, SACE/ED/SELC witness Schlissel, and Public Staff witness Lam.

Witness Rogers testified that it would not be a good idea to substitute nuclear generation for the Cliffside project because a nuclear unit cannot be completed by the time that Duke needs baseload capacity. He stated that Duke is considering the possibility of building nuclear units in addition to the Cliffside project, but that there are many contested issues surrounding nuclear power, particularly the issue of waste disposal, and that there can be no certainty that a nuclear unit will ever be built. In the second hearing, Rogers testified that the ability of new nuclear power plants to achieve commercial operation by the year 2016 is uncertain. No nuclear plant has been licensed under the new regulations of the Nuclear Regulatory Commission (NRC) that permit a combined construction and operating license. While this new NRC approach is promising, it has not yet been tested, and the regulations continue to be revised. There is also uncertainty as to the ultimate cost of new nuclear units.

In the second hearing, SACE/ED/SELC witness Schlissel testified that it is highly uncertain when the new generation of nuclear plants will be built and how much they will cost.

Public Staff witness Lam testified that Duke's proposed in-service date of 2016 for future nuclear units is likely to be delayed because Duke would be among the first in over 30 years to seek a license and begin construction in the United States.

The Commission concludes that Duke cannot rely upon new nuclear generating facilities to meet its need for additional baseload capacity in 2011. The NRC's regulations are still being revised, and no new nuclear plant has yet been licensed. The new nuclear generating units anticipated by Duke would be among the first in the United States in the last 30 years, and it is uncertain whether Duke will be able to place such a unit in commercial operation by 2016, much less by 2011.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the testimony of Duke witnesses Rogers, McCollum, and Hager; NCWARN witness Schlesinger; SACE witness Smith; SACE/ED/SELC witness Cortez; CUCA witness O'Donnell; and Public Staff witness Lam.

Another alternative available to Duke is the construction of an IGCC plant. IGCC is an emerging coal technology that causes less pollution than other forms of coal-fired generation. Witness Rogers testified that Duke considered IGCC technology instead of SCPC technology for the Cliffside project but that Duke ultimately chose not to use IGCC at Cliffside for the following reasons. The initial capital costs of IGCC are expected to be approximately 15% higher than SCPC generation. Although IGCC is more efficient than SCPC in controlling pollutants, it is still a developing technology. There are presently only two operating IGCC units in the United States, both of which are small compared to the proposed Cliffside units. New SCPC plants control pollution very well, even if not as well as IGCC, and they represent the state of the art in commercially available coal-fired generation today. As technology progresses and CO_2 scrubbers become cost-effective for SCPC units, they can be installed at the Cliffside plant. Rogers testified that Duke Energy Indiana will be using IGCC at a plant to be built in Indiana. However, Indiana is a coal-producing state where there is strong government support for IGCC, and Indiana provides tax benefits for IGCC; North Carolina does not. Further, if IGCC plants are to achieve their full potential for controlling CO_2 emissions, the emissions must be sequestered by piping them into an underground geological formation. Suitable formations have been identified in Indiana, but not in North Carolina.

Duke witness McCollum testified that IGCC is a promising, but still developing, technology and that it presents issues of higher initial costs, limitations on load following and cycling capability, and the lack of suitable geological formations in the Carolinas for carbon sequestration. There are only two operational IGCC generating plants in the United States. IGCC plants involve "some very complex and finicky pieces of equipment," and IGCC demonstration plants have taken six to eight years to reach 80% capacity factors. At the second hearing, McCollum testified that the 600-MW Edwardsport IGCC plant that Duke Energy Indiana is planning for 2011 would be the first operational unit of that size in the world. The Edwardsport project is still in a conceptual design phase. Specific bids for major pieces of equipment have yet to be obtained. He stated that there would be a minimum two-year delay to replace the Cliffside project with an IGCC plant. Witness McCollum asserted that IGCC is not the right technology to meet Duke's needs at this time. To the extent that some intervenors suggest building a pipeline to haul CO_2 from the plant to regions where sequestration would be viable, McCollum testified that construction of such a pipeline could easily cost hundreds of millions of dollars. McCollum also testified that Duke is participating in a pilot demonstration project to capture CO_2 from SCPC plants through chilled ammonia technology, and that this technology may bring the cost of carbon capture from SCPC units more in line with the projected cost of IGCC carbon capture.

Duke witness Hager testified that, as compared to a 1600-MW SCPC plant on a brownfield site, the capital cost for a new 600-MW IGCC plant is estimated to be 36% more expensive on a $/kW basis. In preparing the 2006 Annual Plan, it was found that the capital-cost advantage of SCPC was over 50% on a $/kW basis. IGCC was not selected as the most cost-effective option under any scenario analyzed in the 2005, 2006, or the updated modeling, including scenarios that included a carbon tax. Witness Hager testified that IGCC is a potentially viable commercial technology, even in North Carolina where carbon sequestration is not possible, but that it can only be considered as a developing technology, not as a viable option, at present.

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NCWARN witness Schlesinger testified that, because of its greater efficiency and lower emissions, IGCC is a potentially attractive option for baseload plants. Even if CO_2 sequestration is not now available in North Carolina, the construction of an IGCC plant would preserve the option of piping the CO_2 to some distant location or sequestering it in some other manner in the future.

SACE witness Smith testified that IGCC can be an excellent baseload generation technology if the CO_2 emissions are sequestered, and that the Eason Chemical Company[1] is successfully operating an IGCC plant in Tennessee. On cross-examination, he acknowledged that the Eason plant is not an electric generating plant.

SACE/ED/SELC witness Cortez testified regarding the relative costs of SCPC and IGCC generation and the impact of carbon capture on those costs, based on a statistical study of published studies by independent investigators. Based on his review and Duke's updated cost information, he was confident that an "apples to apples" comparison of building similarly sized IGCC and SCPC units at Cliffside would reveal that IGCC is the lower cost resource. With respect to carbon sequestration, he stated that moving CO_2 a distance of 500 miles to sites in central Appalachia does not appear to be an economic barrier to IGCC.

On cross-examination, witness Cortez testified that, while he generally believed IGCC to be superior to SCPC, it was not his testimony that the Commission should choose one technology over the other in this case. He stated that he had not attempted to directly compare the viability of IGCC units and SCPC units at the Cliffside site. Cortez stated his opinion that IGCC is an improving technology and that it has not proven to be as reliable as SCPC.

Public Staff witness Mr. Lam testified that IGCC generation facilities do not have the established reliability history of SCPC facilities and have higher capital costs.

The Commission concludes that Duke cannot rely upon IGCC technology to supply its need for additional baseload generating capacity beginning in 2011. IGCC units have yet to be constructed as a large-scale electric generating resource. Even if such units could be built, they would achieve commercial operation at least two years later than the Cliffside project. Given the geology of North Carolina, a cost effective method for carbon sequestration is, at best, an unresolved issue. Further, IGCC may not operate as effectively as its proponents anticipate. Reliability issues and the higher capital costs associated with IGCC may outweigh any advantages in pollution control; it is too early to know at present. IGCC is still a developing technology, and it is not a reliable alternative to the Cliffside project.

Notwithstanding this conclusion, the Commission is not at all hostile to IGCC technology. In fact, the Commission views IGCC as a promising technological option for the future. G.S. 62-2(a)(5) provides for public utility regulation to "encourage and promote harmony between public utilities . . . and the environment," and the Commission encourages the State's electric utilities to give serious consideration to IGCC as it develops.

[1] Although the transcript reads Eason Chemical Company, the witness more likely referred to the Eastman Chemical Company.

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EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-16

The evidence supporting these findings of fact is contained in the testimony of Duke witnesses Rogers, McCollum, and Hager and Public Staff witness Lam.

The only truly viable alternative to SCPC generation, under the evidence in this case, is the construction of gas-fired CC units. Duke witness Hager testified that the choices for meeting Duke's load in the 2011-12 time frame are either the Cliffside project or CC generation. She stated that Duke has discussed replacing a portion of the Cliffside project with CC if part of the project is sold; however, she strongly believes that it would not be in customers' best interests to replace the entire Cliffside project with CC generation.

Duke witness Rogers testified that, if Duke were to build no more coal generation, i.e., only natural gas generation and nuclear generation, 6% of the Company's energy would come from natural gas and Duke's fuel factor would be 30% higher than it is today. If Duke were to build all gas and no nuclear, 15% of its energy would come from natural gas, and its fuel factor would be 70% higher. He further testified that 50% of the electricity in the United States currently comes from coal and that 50% of the new generation to be built over the next 15 years is projected to be coal-fired, even with carbon regulation, for reasons of energy security. He stated that the country is in the same place with respect to the importation of natural gas today as it was with respect to the importation of oil in the 1960s. Consequently, he questioned whether it makes sense for the country's electric grid to be dependent on imports for its gas supply, in the same way that other sectors of the economy are dependent on foreign oil. Further, if CO_2 emissions are federally regulated in the future, and large numbers of gas-fired units are in use, gas demand will rise faster than gas supply, driving prices up.

Public Staff witness Lam testified that the only viable alternative to SCPC generation for supplying Duke's baseload capacity needs in the 2011-12 time frame is gas-fired CC generation. Witness Lam stated, however, that reliance on this option is inferior to the proposed SCPC units for the following reasons. The use of natural gas will result in an increased system fuel cost compared to SCPC and will rely on a currently decreasing domestic gas supply. Because CC units operate at lower capacity factors than baseload coal units, relying on them as a resource option would necessitate timely completion of the proposed nuclear units by 2016. Further, reliance on CC units would cause current non-emission-controlled, older coal units to operate at higher capacity factors than today, with the potential for expensive pollution control equipment and decreased system reliability.

With respect to the advantages of SCPC, Duke witness Rogers testified that the Cliffside project represents state-of-the-art technology in terms of emissions control as well as operational efficiency. By using SCPC technology at Cliffside and retiring Cliffside Units 1-4, Duke can substantially increase its baseload capacity without significantly increasing its environmental footprint. He further stated that the Cliffside project will give Duke the flexibility to run its older, highest-emitting coal units less frequently and to accelerate the retirement of some of those units on a MW-for-MW basis as demand reduction goals are met. Witness Rogers asserted that, as the proposed Cliffside SCPC units displace an equivalent capacity of older coal units, Duke will be able to burn less coal and produce more electricity.

Witness McCollum testified that the Cliffside project, including the retirement of Units 1-4, will reduce total current SO_2 emissions at the Cliffside site by nearly two-thirds, reduce total site NO_x emissions under normal operations, reduce water withdrawal from the Broad River, and eliminate the existing thermal discharge into the river. He further testified that new Cliffside generation would be the first coal generation dispatched on the Duke system and would have a beneficial impact on overall emissions from the entire Duke coal-fired fleet.

Witness Lam testified that use of new, highly efficient SCPC technology will keep Duke's overall system emission levels neutral, or potentially lower, on a per-unit-of-delivered-energy basis, because these units will displace less efficient coal units.

The Commission concludes that gas-fired CC generation is less attractive than SCPC generation for meeting Duke's baseload capacity needs and that Duke should not rely upon gas-fired CC for all of the 800-MW baseload need identified beginning in 2011. The Commission reaches this conclusion for several reasons. CC generation technology is well established and commercially available; however, there are several practical reasons why CC technology must be considered less desirable than SCPC technology in this case. One of these reasons is the greater volatility of natural gas prices compared to coal prices. Obviously, it is impossible to predict future fuel prices with any certainty, but it is clear that gas prices tend to vary over a wider range than coal prices. Duke's fuel factor could be adversely impacted if Duke builds only CC generation. Further, CC plants typically operate at lower capacity factors than SCPC plants. This is appropriate for intermediate or peaking needs, but less so for baseload capacity. Gas-fired CC generation has its appropriate place in a balanced generation portfolio, but if CC generating units were built for baseload generation (instead of SCPC at Cliffside), Duke would have to run its older coal-fired units more often and would not be able to retire Cliffside Units 1-4.[1] Greater use of the older coal units will lead to increased emissions or increased cost for pollution control. Finally, the United States' future supply of natural gas is expected to become increasingly dependent on imports. Over-reliance on gas in baseload applications would not be prudent.

The best remaining alternative available to Duke is SCPC technology as proposed for Cliffside, and the Commission concludes that use of SCPC has significant advantages and is the most desirable technology for Duke under the present circumstances. There is an abundant, domestic supply of coal. The fact that coal prices are not as volatile as gas prices makes coal a more attractive choice for baseload generation. Duke is already planning to build considerable gas-fired generation for intermediate needs, and fulfilling the present baseload needs with coal adds to the company's overall fuel diversity and security. As witness Hager testified, "History has shown that 'putting all your eggs in one basket' or, in this case, relying on a single fuel to meet all future demand is not the most prudent course of action for customers." Under the Shared Ownership portfolio, which is equivalent to our present decision in terms of fuel diversity, Duke would end up depending on gas-fired generation for only 25% of capacity and 3% of energy in 2021. Finally, coal plants typically operate at a higher capacity factor than gas plants, allowing Duke greater flexibility to accelerate the retirement of older coal units. The Commission concludes that use of modern SCPC technology, together with the retirement of Cliffside Units 1-4, will make for a more diverse and secure generation fleet and will allow Duke

[1] Duke's All Gas and Nuclear and its All Gas portfolios did not include retirement of Cliffside Units 1-4.

to increase its baseload generating capacity without significantly increasing its environmental footprint.

Duke's commitment to retire Cliffside Units 1-4 applies in the present case, where the Commission has certificated only one Cliffside unit. One of the original portfolios presented by witness Hager, the Balanced Single Unit Cliffside portfolio, included the retirement of Cliffside Units 1-4 along with construction of only one 800-MW unit at Cliffside. At the second hearing, Hager presented the Shared Ownership portfolio. During cross examination by the Attorney General, witness Hager testified that the Shared Ownership portfolio assumes that a partner would own 800 MW, that Duke would not buy back any of the partner's capacity, and that Cliffside Units 1-4 would still be retired. She testified, "So we would own 800 of it, but we would retire 200, leaving us with a net [of] 600 for the analysis." At another point, witness Hager testified that "you get the same megawatts out of [both the Balanced Single Unit Cliffside portfolio and the Shared Ownership portfolio]." Duke's testimony foresaw that it may end up owning only one unit, that it would nonetheless retire Cliffside Units 1-4, and that it would gain 600 MW of capacity in such an event. The retirement of Cliffside Units 1-4 will, therefore, be made a condition of the certificate granted herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Duke witness McCollum and Public Staff witness Lam.

Duke witness McCollum testified to the comprehensive three-phase siting study that Duke conducted to determine the optimum location for its new baseload generation. The study identified the Cliffside site and an alternate site in South Carolina as the recommended locations for the new generating units. Duke selected the Cliffside site because it received the highest combined ranking in the siting study and because its existing critical infrastructure will keep construction and operating costs low and will minimize environmental impacts. The Company has a long-established presence in the community and has received strong support for the project from both Rutherford and Cleveland Counties.

Public Staff Witness Lam testified that the Cliffside site is an "excellent" choice, due to its existing infrastructure and available land. No party introduced evidence challenging the selection of the Cliffside site.

The Commission concludes that Duke appropriately selected the site for the Cliffside project.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is contained in the testimony of Duke witnesses McCollum, Rose, and Hager; and Public Staff witnesses Maness and Lam.

Duke submitted confidential cost estimates for the Cliffside project, under seal pursuant to G.S. 132-1.2, in Attachment 1 to McCollum Exhibit 1. At the September hearing, McCollum testified that the Company evaluated proposals from four leading power engineering, procurement, and construction contractors and compared these proposals to industry-standard EPRI data and to Duke's own experience to formulate the cost estimate for the Cliffside project. Duke selected Shaw Stone & Webster as contractor to develop firm scope, schedule, terms, and pricing for the project.

Public Staff witnesses Maness and Lam testified that they reviewed and found the estimated construction cost to be reasonable.

Duke provided updated cost information to the Commission in its October 25, 2006 filing that showed a significant increase in the bid prices from vendors. At the second hearing, witness McCollum testified that Shaw Stone & Webster and Duke have received and evaluated bids for the boiler, steam turbine generator, and air quality system controls and that these bids suggest that the capital costs for major components of the Cliffside project could be 40 percent higher than estimated at the first hearing. Witness Rose explained that there has been a rapid increase in steel and other prices. He attributed this to a substantial increase in demand for the materials both domestically and internationally. After receiving the certificate and air permit, Duke will receive firm bids and enter into contracts with various equipment vendors.

Duke witness Hager was asked about the construction cost of the Balanced Single Unit Cliffside portfolio during the second hearing, and she testified as to the cost of building one 800-MW unit at Cliffside. She testified that the cost "for a single unit is $1.53 billion without AFUDC, and the AFUDC is $400 million."[1]

The granting of a certificate requires Commission approval of the cost estimate for the construction being proposed and a finding that the construction is consistent with the Commission's plan for expansion of electric generating capacity. We find that the Company has reasonably forecasted the costs associated with the Cliffside project vis-a-vis alternatives. Witness Hager testified as to the cost of building one 800-MW unit at Cliffside. We find her estimate to be reasonable, and it is approved for purposes of this proceeding. The Commission notes that its approval is made only in the context of this proceeding, which is concerned with approving whether or not Duke can proceed with the construction of the plant, and does not apply to any ratemaking determination or proceeding.

The Commission further notes that Duke is required by G.S. 62-110.1(f) to provide the Commission with an annual progress report and any revisions to the cost estimate. Witness Maness noted that the estimated costs of the project are expected to be finalized shortly after the first quarter of 2007. He recommended that Duke be directed to file a special report within 30 days after the estimate is finalized, but in no event later than May 31, 2007, and that Duke be given the opportunity to file supplemental reports updating the estimate every 30 days after the initial report. The Commission agrees with Maness's recommendations on the filing of cost estimates by Duke. The ordering paragraphs set out below will provide for these reports.

[1] This testimony was given during a confidential portion of the January 19, 2007 hearing, but Duke authorized its use in this order by its March 14, 2007 letter.

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EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

Duke witness Hager testified about a time in the 1960s when Duke had to build a new generating plant. Least cost planning showed that an oil-fired plant with a pipeline to Charleston would be the best choice. However, Hager testified, Duke management was uncomfortable with that course and, instead, "we built the Marshall plant which...has consistently won the most efficient coal plant in the country many times over...we used management judgment and I think our customers are significantly better off because we did that." The Commission now finds itself in a similar situation. The Commission is charged with responsibility for certificating new electric generating plants. This has been a particularly complex undertaking in this case and a difficult decision, but the Commission has used its best judgment based upon the evidence presented.

First, the Commission examined the need that the proposed generation must serve. Based upon Duke's most recent plan and upon Duke's consideration of selling up to half of the generation it proposes, the Commission cannot find that Duke has shown a need for 1600 MW of new baseload capacity. Duke presented no evidence of a regional or joint need, beyond its own need, to be served by the proposed plant. Duke did present evidence that it needs 800 MW of baseload generating capacity beginning in 2011, which it proposes to meet with coal.

Next, given a need for 800 MW of baseload capacity, the Commission has examined the various alternatives available to Duke. Each of them presents difficulties. If Duke takes no action, it would become dependent on purchases, and other utilities may have insufficient power available for sale in periods of peak demand. Duke did not issue a request for proposals (RFP) for its 2011 baseload capacity needs. Duke witness Hager testified that Duke has used the wholesale market for peaking and intermediate capacity, but that baseload capacity is fundamentally different. Hager cited possible transmission interruptions outside its control area ("there is no baseload merchant generation in our service area or even in the ...region that we're aware of") and supplier defaults ("monetary compensation for failure to perform under a baseload contract [is] a poor substitution for the energy that a baseload unit would produce") as key concerns with using the wholesale market for baseload capacity. On the present record, without setting a precedent for other cases, the Commission cannot conclude that Duke should have issued an RFP for the capacity at issue herein. Duke is expanding its DSM initiative and has committed to invest significant funds in this effort, but the Commission cannot conclude that cost effective DSM programs can eliminate or delay the need for new generation facilities in 2011. The main benefits of Duke's DSM efforts will be realized in the years beyond that time. Similarly, the Commission cannot conclude that there are sufficient renewable resources to eliminate the need for construction of a more conventional generating plant by 2011. Furthermore, Duke will not be able to bring a nuclear plant into operation by 2011. Although Duke has offered evidence that a nuclear facility might be completed by 2016 at a favorable cost, it is entirely possible that such construction may be delayed and its costs may increase. IGCC causes less pollution than other forms of coal-fired generation, but carbon sequestration has not yet been perfected, there are no suitable geological formations for sequestration in North Carolina, and IGCC is an emerging technology that is not currently viable.

Finally, Duke -- and the Commission -- are left with a choice between natural gas CC generation and SCPC. The Commission concludes that there are several practical reasons why natural gas CC must be considered less desirable. One of these reasons is that gas prices tend to vary over a wider range than coal prices. A second reason is that natural gas CC plants typically operate at lower capacity factors than coal plants. If Duke builds gas-fired generation now, Duke will have to run its older coal-fired units more often than if it builds coal-fired generation now. The United States' natural gas supply is expected to become increasingly dependent on imports and, thus, not as secure for baseload applications as the domestic supply of coal. Finally, Duke is planning to build a number of gas-fired generating plants in the coming years, and using coal for its baseload capacity needs in 2011 will tend to diversify its generation fleet. Even without the economies of scale that would have been associated with building two SCPC units at Cliffside, the Commission believes that SCPC generation is the appropriate choice for all of the above reasons. One final advantage of the present decision is that technology appears to be moving forward in the areas of pollution control and IGCC generation. Approving one unit now will allow time for these technologies to develop before Duke needs to build more baseload generation. Approving one unit now, together with the retirement of older, coal-fired units, limits Duke's carbon footprint and serves as a hedge against the prospect of carbon regulation.

At one point, Hager testified that "we won't know which was the right decision for many, many years ultimately." That is true with respect to this order; however, given the level of need demonstrated by Duke's testimony and 2006 plan, the size and mix of Duke's existing capacity, the estimated construction costs, the uncertainties of the future, the various risks as to plant costs and fuel costs, the costs and benefits of alternative technologies and developing technologies, and the necessity to make a decision now for commercial operation of coal-fired generation in 2011, the Commission concludes that approval of one 800-MW coal-fired unit is the best of the alternatives available and is consistent with the Commission's plan for expansion of electric generating capacity.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity should be, and is hereby, granted to Duke Energy Carolinas, LLC for the construction of one 800-MW supercritical pulverized coal electric generating facility to be located at the existing Cliffside Steam Station situated on the border of Cleveland and Rutherford Counties, North Carolina, together with related transmission facilities, subject to the following ordering paragraphs, and the present order shall constitute the certificate.

2. That Duke shall retire existing Cliffside Units 1 through 4 no later than the date of the commercial operation of the one 800-MW unit certificated herein.

3. That Duke shall honor its commitment to invest, on an annual basis, 1% of its annual retail revenues from the sale of electricity in energy efficiency and demand side programs, subject to the results of the ongoing collaborative workshops and subject to such appropriate regulatory treatment as the Commission may determine to be just and reasonable, and that Duke shall retire older coal-fired generating units (in addition to Cliffside Units 1 through 4) on a MW-for-MW basis, considering the impact on the reliability of the entire system, to

account for actual load reductions realized from these new programs, up to the MW level added by the one Cliffside unit certificated herein.

4. That all such energy efficiency and demand side programs shall be submitted to the Commission for approval and shall be accompanied by a comprehensive plan for verifying MW savings. Duke shall file an annual report with the Commission on March 1 of each year setting forth the investment in each approved program for the preceding year. In addition, on March 1 of each year, Duke shall submit an annual plan for identifying the number of MW saved and the coal units to be retired.

5. That, within 30 days after the estimated cost of the Cliffside project is finalized, but in no event later than May 31, 2007, Duke shall file with the Commission a report detailing such estimated costs, and Duke may file with the Commission a report updating the initial report every 30 days thereafter, until the filing of the first annual report provided in the following ordering paragraph.

6. That, during the month of February of each year, beginning in 2008, Duke shall file with the Commission a progress report which shall provide information upon which the Commission may evaluate the current status of the construction of the unit certificated herein, including the cost thereof and any revisions to the cost estimate, and the time at which it is anticipated that said unit will become operational.

7. That the unit certificated herein shall be constructed and operated in strict accordance with all applicable laws and regulations, including the provisions of all permits issued by the North Carolina Department of Environment and Natural Resources.

8. That issuance of this order does not constitute approval of the final costs associated herewith for ratemaking purposes and this order is without prejudice to the right of any party to take issue with the ratemaking treatment of the final costs in a future proceeding.

9. That, should renewable portfolio standard legislation be enacted either by the United States Congress or the North Carolina General Assembly, Duke shall discuss such legislation with the parties to this docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of March, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L Mount, Deputy Clerk

Commissioner Robert V. Owens, Jr. dissents.

Ah032107.01

ELECTRIC – ELECTRIC GENERATION CERTIFICATE

DOCKET NO. E-7, SUB 790

Commissioner Robert V. Owens, Jr., dissenting:

There comes a point, as one young lady public witness said in Charlotte, when you must quit talking the talk and begin walking the walk, when you just have to put your foot down and say "Enough!" For me, as one commissioner, in the building of coal-fired electric generating facilities, that time is now.

Much of the history of the United States is marked by innovation to meet necessity, by sacrifice of the comfortable and expedient in order to meet a glaring need or deficiency. Nowhere in our society is the need for that characteristic greater today than in energy production. Until we put our foot down and say "It's Time!" and, as a society, make the hard decisions and sacrifices required, we will not begin the process of remaking our energy production process into one which will not continue to destroy the environment. We are regulators, chosen and governed by a process and laws designed to let us to make independent decisions, decisions which are not politically expedient. We are uniquely situated to make the hard decisions which the industry or other, more politically directed, decision makers cannot or will not make. As John Kennedy asked: "If not us, who? If not now, when?"

If we are to approach the current environmental crisis like President Jimmy Carter said we should attack the energy crisis of the late 70's, as "the moral equivalent of war," then we must prepare ourselves to make sacrifices for our survival on this earth. The American public, if not the American shareholder, have proven time after time to be remarkably resilient and willing to make such sacrifices when necessary and when the goals are worthy and clear. There is no clearer need and no worthier goal than trying to reduce the damage we continue to do to the environment and to preserve a livable planet for our children and grandchildren.

So far, American industry in general, and the electric power industry in particular, has been reluctant to participate in environmental and green power programs. Management, directed by its investors, has pursued profits at the expense of the long-term health of our world. Sometimes, it has given token attention to the environmental destruction it causes, and sometimes has given lip service to reducing its impact. But it's usually only when the government steps in that industry can be forced to act. Only when the legislature threatened harsh legislation did the industry negotiate the clean smokestack bill, for instance. That is understandable because if a power industry manager were to take some kind of courageous pro-environmental stand which would cause his or her shareholders to sacrifice profit and the public to pay higher rates, he or she would be unemployed virtually instantly. That is neither new nor unique. Since the Industrial Revolution, industry has had to be forced to act in anything other than its own selfish interest. Safety, labor and environmental improvements in industry have come only when they have been forced upon industry by popular will, by collective force or by government. From the latter half of the 20th century, it has more often than not been government who has stepped in to force industry to clean up its impact on our air and water and other natural resources. The free market, as much as I and others love it and work hard to protect it, has not led to the kind of innovation we absolutely must employ in this struggle. Besides, our electric industry does not operate in a free market. It is regulated by its investors and by the government. Its investors are not willing to make the kind of sacrifices required to preserve the environment over the long term. Government must act if it is to be done. As the direct regulators of the industry and the closest government agency to the problem, we have the authority and the legal and moral responsibility to do something about it.

We have forced our electric utilities to adopt demand-side management programs, integrated resource management programs, energy efficiency programs and green power programs throughout the years. In this order, the majority requires more such efforts from Duke (although any actual program is still in someone's mind) to the tune of one per cent of its annual retail revenues. As the kids of today say: "Say What!" Such efforts are laudable but woefully inadequate. The efforts made up to now and which the majority will require in this case amounts to a band-aid on a gaping wound. It might help stop a little bit of the bleeding, but it doesn't do much to correct the problem.

The problem is so well-documented and universally acknowledged by scientists worldwide that it is not even seriously debated anymore. The burning of fossil fuels pollutes our air and leads to global warming. The results are dramatic and drastic and its long-term effects potentially catastrophic for future generations. The only way to stop it is to stop burning fossil fuels. We will fail in our legal responsibilities to the people of North Carolina and in our moral responsibilities to our children and grandchildren if we do not take bold, decisive action to address the problem, not just deal with the symptoms.

North Carolina General Statute §62-110 and §62-110.1 set out the legal standards for granting a certificate of public convenience and necessity for constructing a plant to generate electricity. Neither of those statutes repeals, changes or modifies §62-2, the General Assembly's declaration of policy. In addition to the provisions about protecting the public interest and ensuring fair treatment for the utilities and the public, there is provision (5) which directs us to "[e]ncourage and promote harmony between public utilities, their users and the environment". It is not a subservient or secondary provision. It stands on equal footing with the other provisions. §62-2 gives us the authority and the responsibility to regulate public utilities to carry out the General Assembly's policy. The continued burning of fossil fuel to generate electricity does nothing to encourage or promote harmony between the utilities and the environment, in fact is does just the opposite. I see it as my legal duty to do all I can to prevent it.

I do not dispute Duke's need for 800 megawatts of new generating capacity and I applaud the majority's decision to cut the 1600 megawatt request in half. Where I differ with the majority is in the building of a coal-fired facility to achieve the new capacity. Certainly the retirement of older coal-fired units as required by the majority is desirable and must be accomplished. But replacing, megawatt for megawatt, coal-fired generation with coal-fired generation, no matter how much cleaner the new generation, continues to contribute to the problem.

The GDS Associates and La Capra Associates studies prepared for us and included in the record of this docket indicate that sufficient savings from energy efficiency and existing renewable energy sources could eliminate the need for this new coal-fired plant. Duke fails to adequately account for either resource and completely ignores available renewable energy resources in its analysis. The time and effort spent on developing new pollution sources would more wisely be spent on developing non-polluting sources of generation; just as the time and money spent trying to recover nuclear development costs early could more efficiently be spent developing the resource.

Governments, state and federal, are going to force utilities to reduce their contributions to global warming eventually. It is as inevitable as the companies' resistance to such change. The companies will try to negotiate a smaller reduction or a less costly alternative just like always. But if we are serious about the environmental impact of generating electricity, we will prohibit coal-fired plants being built to replace coal-fired plants. While we may not in our lifetimes see coal completely replaced as a fuel of choice for electricity production, and while we may not see fossil-fuel completely eliminated as a fuel source, nuclear-powered plants and the growing abundance of renewable resources can and, I think, eventually will replace coal in electricity generation. We should encourage such replacement when we can and require it when we can. The surest way to speed it up, however, is to begin here and now; to walk the walk, to put our collective foot down and say "Enough!"

Because I believe we should prohibit the building of another coal-fired generating facility in North Carolina, I respectfully dissent.

\s\ Robert V. Owens, Jr.
Commissioner Robert V. Owens, Jr.

DOCKET NO. E-7, SUB 751

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Power Company LLC,	)	ORDER ON
d/b/a Duke Energy Carolinas, LLC, for	)	RECONSIDERATION AND
Authorization to Share Net Revenues from	)	APPROVING OFFER OF
Certain Wholesale Transactions	)	SETTLEMENT

HEARD: Monday, December 18, 2006, at 1:00 p.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27603

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; and Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, James Y. Kerr, II, Howard N. Lee, and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

Lara S. Nichols, Associate General Counsel, Post Office Box 1006, Charlotte, North Carolina 28201

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For Carolina Utility Customers Association, Inc.:

James West, West Law Offices, P.C., Suite 1735, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

BY THE COMMISSION: This matter arose upon the filing of an application on May 17, 2004, by Duke Power[1], a division of Duke Energy Corporation (Duke or the Company), requesting approval to share an amount equal to 50% of a North Carolina retail allocation of net revenues derived from BPM Sales, defined as the non-firm wholesale sales under the Company's FERC-jurisdictional Market-Based Rate. Duke proposed to share up to $5 million per year

[1] In connection with the merger of Duke Energy Corporation and Cinergy Corp., Duke Energy Corporation was converted into a limited liability company, Duke Power Company LLC, d/b/a Duke Energy Carolinas, LLC, which is now called Duke Energy Carolinas, LLC. For purposes of this Order, Duke Power and Duke Energy Carolinas, LLC, will be referred to as Duke or the Company.

through its Share the Warmth, Cooling Assistance, and Fan-Heat Relief programs and the Community and Technical College Challenge Grant Fund for worker training, and the remainder through a reduction in the kWh rate for each block in the industrial classification in accordance with a proposed Rate Adjustment Rider (Rider).

Because the proposed sharing of BPM Net Revenues with industrial customers might be regarded as a change in base rates that would otherwise be prohibited under the rate freeze provisions of the Clean Smokestacks Act, Duke filed the application pursuant to G.S. 62-133.6(e)(2), which permits the Commission, if consistent with the public interest, to approve a reduction in rates to a class of customers during the freeze period upon request of the utility.

In support of the application, Duke stated that it had initiated various programs to stimulate economic development in its service area and now sought a means to also help established industries, believing that a healthy industrial base is good for all of its customers. Duke further stated that the proposed sharing program would enhance the relief already being provided to customers in great financial need and give needed impetus to job training efforts.

BPM Net Revenues for sharing were defined in the application and in the proposed Rider. Duke stated that this same formula would be used in reporting BPM Net Revenues corresponding to BPM Sales occurring beginning January 1, 2004, separately from jurisdictional retail operations in the Company's quarterly NCUC E.S.-1 Reports, beginning with the report for the twelve months ended March 31, 2004.

Duke further stated that BPM Net Revenues on BPM Sales made beginning January 1, 2004, and continuing until the earlier of December 31, 2007, or the effective date of any rates approved by the Commission after a general rate case under G.S. 62-134 or 62-136, would be subject to the proposed Sharing Arrangement. This period was referred to as the Net Revenue Calculation Period. The period during which contributions would be made to the community assistance and worker training programs and during which industrial rates would be reduced by the applicable Rider was referred to as the Sharing Period.

As proposed, the first Rider would be calculated based on BPM Net Revenues from January 1, 2004, through March 31, 2004, and would be effective through June 30, 2005. The second Rider would be calculated based on BPM Net Revenues from April 1, 2004, through December 31, 2004, and would be in effect from July 1, 2005, through June 30, 2006. Subsequent Net Revenue Calculation Periods were to be the calendar years 2005, 2006, and 2007; the corresponding Sharing Periods were to be the twelve months beginning July 1 of the following years.

The matter was presented for Commission consideration at the Regular Commission Conference on June 1, 2004. By Order issued June 9, 2004, the Commission approved the application as filed.

On August 2, 2004, Duke filed its first Rider under the Sharing Arrangement. The proposed rate decrement was 0.1336¢/kWh (excluding gross receipts tax (GRT)), effective

September 1, 2004, through June 30, 2005. According to schedules submitted with the filing, the Company calculated BPM Net Revenues of $45,772,000, and an amount eligible for sharing with industrial customers of $15,102,223, for the first quarter of 2004. Emission allowance costs used in the calculation of the Rider were $5,183,000. Total BPM Sales for that period were $128,308,000. On August 27, 2004, the Public Staff submitted a letter recommending that the Rider be allowed to become effective as filed.

On June 1, 2005, Duke filed its second Rider under the Sharing Arrangement. The proposed rate decrement was 0.0224¢/kWh (excluding GRT), effective July 1, 2005, through June 30, 2006. According to schedules submitted with the filing, the Company calculated BPM Net Revenues remaining to share for April through December 2004 of $19,505,000 and an amount eligible for sharing with industrial customers of $3,218,161. Subsequent to the filing, Duke and the Public Staff disagreed as to the method of calculating incremental emission allowance costs, but they agreed, for purposes of the second Rider, that the appropriate amount of emission allowance costs would be $6,016,656, based on the costs of allowances purchased in 2004, instead of replacement costs of $9,979,000, as the Company had originally proposed. Duke and the Public Staff further agreed to meet and discuss the appropriate methodology for determining the incremental cost of emission allowances for the purpose of calculating future Riders. On June 27, 2005, Duke filed a revised Rider of 0.0322¢/kWh (excluding GRT) for the Sharing Period beginning July 1, 2005. Schedules submitted with the filing showed BPM Net Revenues remaining to be shared for 2004 of $23,467,000 and an amount eligible for sharing with industrial customers of $4,633,586. Total BPM Sales for the entire year 2004 were $207,630,000. By Order issued June 30, 2005, the Commission allowed the revised Rider to become effective as filed.

Subsequent to implementation of the second Rider, Duke, the Carolina Utility Customers Association, Inc. (CUCA), and the Public Staff were unable to reach agreement on the appropriate methodology for determining the incremental cost of emission allowances for purposes of calculating the next Rider under the Sharing Arrangement. On May 1, 2006, Duke filed its third Rider, again using replacement costs for emission allowances in the BPM Net Revenues calculation. The proposed rate decrement under the Rider was 0.3702¢/kWh (excluding GRT), effective July 1, 2006, through June 30, 2007. According to schedules submitted with the Rider, Duke calculated BPM Net Revenues for 2005 of $164,530,000 and an amount eligible for sharing with industrial customers of $53,761,890. Total emission allowance costs used in the calculation of the Rider were $39,163,000. Total BPM Sales for 2005 were $407,350,000. The Public Staff disagreed with the Company's methodology for costing emission allowances and moved the Commission to allow comments on the issue. By Order issued May 10, 2006, the Commission granted the Public Staff's motion. Comments were filed by Duke, the Public Staff, and CUCA on May 19, 2006; reply comments were filed on June 2, 2006.

Duke defended its use of replacement cost to determine the incremental cost of emission allowances for purposes of calculating the Rider, while CUCA and the Public Staff proposed methodologies using the historical cost of allowances purchased by the Company. CUCA asserted that Duke's BPM Net Revenues should be calculated on the basis of actual average historical costs of emission allowances. The Public Staff argued that the highest-cost emission allowances actually expensed during the year should be assigned to BPM Sales, and provided an example of its proposed methodology.

On June 28, 2006, the Commission issued an Order concluding that the methodology proposed by the Public Staff was the most appropriate for purposes of this proceeding and requiring Duke to recalculate the Rider in a manner consistent with that methodology. The Commission ordered the Company to file the revised Rider on or before June 29, 2006, and to implement the revised Rider effective July 1, 2006.

On June 29, 2006, Duke filed a motion for postponement of the effective date of the Commission's Order. By Order issued June 30, 2006, the Commission granted the motion, thereby postponing the date for filing the revised Rider until July 21, 2006; requiring the Company to implement the revised Rider on August 1, 2006, for a sharing period through June 30, 2007; and allowing the current decrement to continue in effect until the effective date of the revised Rider with the understanding that the continuation would be trued up by the revised Rider. On July 17, 2006, Duke filed a motion for reconsideration and requested that the Commission allow the Rider filed on May 1, 2006, to be implemented effective August 1, 2006, pending consideration of the motion, subject to true-up to reflect the Commission's final disposition of the matter.

In its motion, Duke requested the Commission to reconsider its decision and reinstate the Rider as filed using the replacement cost of emission allowances in calculating BPM Net Revenues. Alternatively, the Company requested the Commission to make its Order effective only prospectively with respect to sharing periods beginning January 1, 2007. In addition, if the Commission was not inclined to reinstate the Rider as filed, Duke requested the Commission to approve the Company's withdrawal of the Rider, at its option. On July 20, 2006, the Commission issued an Order requesting comments on the motion for reconsideration, scheduling oral argument, and allowing the proposed Rider to become effective on a provisional basis subject to true-up.

Comments were filed by CUCA and the Public Staff on August 8, 2006; reply comments were filed by Duke on August 22, 2006. On August 29, 2006, the matter came on for oral argument as scheduled. On September 15, 2006, Duke and the Public Staff submitted an Offer of Settlement, and the Commission issued an Order requesting that CUCA file comments. CUCA filed its comments with regard to the Offer of Settlement on September 25, 2006.

On November 2, 2006, the Commission issued an Order (1) stating that, on the basis of the existing record, it had been unable to resolve the outstanding issues presently under reconsideration, and (2) finding good cause to set Duke's motion for reconsideration for evidentiary hearing pursuant to G.S. 62-80 to determine whether the June 28, 2006, Order should be rescinded, altered, amended, or affirmed. Citing State ex rel. Utilities Commission v. Thrifty Call, Inc. 154 N.C. App. 58, 571 S.E.2d 622 (2002), disc. rev. denied, 357 N.C. 66, 579 S.E.2d 575 (2003) (Thrifty Call), the Commission determined that an ambiguity necessitating resort to extrinsic evidence existed with respect to provisions of the BPM tariff and noted that the record was devoid of any such evidence that had been subject to adversarial testing. The Commission further noted that it had been presented with a non-unanimous settlement, which raised issues as to the extent of its legal authority to adopt the settlement and about the factual basis of the settlement. Accordingly, the Commission scheduled the matter for hearing on January 9, 2007, for the purpose of considering evidence on the proper interpretation of the relevant language in the BPM Revenue Sharing Rider and on whether the Offer of Settlement should be approved or rejected.

On November 6, 2006, Duke filed a request that the Commission expedite the hearing schedule established in the November 2, 2006, Order, asserting that concluding the matter before the end of 2006 would permit the Company to close its books for that year without leaving this issue unresolved. By letter of November 8, 2006, CUCA opposed the request for an expedited hearing. On November 9, 2006, the Commission issued an Order modifying the schedule to provide for hearing on December 18, 2006.

On November 15, 2006, Duke filed the joint testimony of Janice D. Hager, Vice President, Rates and Regulatory Affairs, and David B. Johnson, an Originator in the Business Development & Origination Group. On December 8, 2006, the Public Staff filed the testimony of Michael C. Maness, Supervisor, Electric Section, Public Staff Accounting Division, and CUCA filed the testimony of Kevin W. O'Donnell. On December 13, 2006, Duke filed the rebuttal testimony of Ms. Hager, and the Public Staff filed the rebuttal testimony of Mr. Maness.

On December 29, 2006, the Commission entered a Notice of Decision in this docket whereby the Commission found good cause to (1) reconsider the June 28, 2006 Order Ruling on Issue and Requiring Revision of Rate Decrement; (2) rescind said June 28, 2006 Order; and (3) approve the Offer of Settlement filed on September 15, 2006, by Duke and the Public Staff. The Commission further stated that it would, as soon as reasonably possible, enter a further Order setting forth detailed findings of fact and conclusions in support of the decision contained in the Notice of Decision and that the time for appeal of the Commission's final decision would run from the date of entry of such further Order and not from the date of the Notice of Decision.

Based on the evidence adduced at the hearing, and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. The post event dispatch model referred to in the BPM tariff, as intended by Duke and understood by the Public Staff, is a computer program called Post Analysis and Cost Evaluation (PACE) that is used for after the fact analysis of actual dispatch of generation and purchased power and ranking of generation and purchased power based on cost.

2. The PACE model assigns generation and purchased power to serve retail and cost-based wholesale load by stacking each dispatched resource by hour from least cost to highest cost based on the incremental heat rate of each unit and the associated variable O&M, incremental fuel, and incremental emission allowance costs.

3. The PACE model has been used by Duke since 1996. The logic of the model has not changed since the BPM Sharing Rider was approved, although Duke received an updated version of the software in November 2004.

4. Key inputs to the PACE model include incremental fuel costs, variable operations and maintenance (O&M) costs, average and incremental heat rates, minimum and maximum unit generation capacity, start up costs, ramp rates, minimum start up and coast down times, and incremental emission allowance costs.

5. The PACE model does not specify the values of the various inputs to be used in applying the computer program.

6. Duke has used replacement cost as determined by settled market prices reported by independent price indices to determine the incremental cost of emission allowances since 2000 for the purposes of dispatching its units, making economic decisions regarding entering into BPM Sales, assigning generating resources to BPM Sales using the PACE model, and determining the cost of emission allowances in connection with its fuel reporting in South Carolina, where the cost of SO_2 allowances is recovered through the fuel clause.

7. At the time Duke filed its application in this docket, the Company intended to use the replacement cost of emission allowances in calculating BPM Net Revenues pursuant to the Sharing Rider, and it has consistently used this methodology in its Rider filings since August 2004.

8. At the time Duke filed its application in this docket, the Public Staff was generally familiar with the PACE model as a result of its review of fuel costs in the Company's annual fuel proceedings, but it had no particular reason to be aware of the Company's valuation of emission allowances in the model since emission allowances are not included in fuel costs in North Carolina.

9. In August 2004, the Public Staff received a data response from Duke stating that the Company had used replacement costs to determine incremental emission allowance costs in calculating the first Sharing Rider, but the Public Staff did not recognize the significance of this response and the response was not brought to the Commission's attention at that time.

10. In June 2005, the Public Staff voiced disagreement with Duke's use of the replacement cost methodology with respect to the second Sharing Rider, and the Company agreed to file a revised Rider based on a different methodology and to meet with the Public Staff to hold further discussions prior to filing the third Sharing Rider.

11. During the Net Revenue Calculation Period of January 1, 2005, through December 31, 2005 (the 2005 Net Revenue Calculation Period), and the first six months of the Net Revenue Calculation Period of January 1, 2006, through December 31, 2006, Duke used accrual accounting to record the amount expected to be shared based on its replacement cost methodology for determining the incremental cost of emission allowances associated with BPM Sales.

12. Duke's use of replacement cost to determine the incremental cost of emission allowances resulted in an allocation of allowance costs to BPM Sales of approximately

\$39 million for the 2005 Net Revenue Calculation period, while its total recorded actual allowance expense for that period was approximately \$8 million.

13. Duke credited the difference between the \$39 million replacement cost and the \$8 million expense to cost of service for retail and native load wholesale customers in its quarterly earnings reports (NCUC Form E.S.-1) to the Commission.

14. When Duke and the Public Staff discussed emission allowance costing methodologies in the spring of 2006, the Public Staff proposed a specific methodology based on highest historical cost; when the parties were unable to agree on a methodology, the Public Staff proposed the same methodology to the Commission in its comments filed in May of 2006.

15. The effect of the Commission's June 28, 2006 Order adopting the Public Staff's methodology for Net Revenue Calculation Periods beginning January 1, 2005, should it remain in full force and effect, would be to require Duke to share approximately \$18 million more in BPM Net Revenues than the Company considers appropriate for the period January 1, 2005, through June 30, 2006.

16. The use of replacement cost to determine the incremental costs of emission allowances for purposes of calculating BPM Net Revenues, as advocated by Duke, is just and reasonable for the Net Revenue Calculation Periods beginning January 1, 2005, through June 30, 2006.

17. The Offer of Settlement includes an agreement by the Public Staff not to oppose the use of Duke's methodology for calculating BPM Net Revenues for the 2005 Net Revenue Calculation Period and the first six months of the 2006 Net Revenue Calculation Period and an agreement by Duke to use the Public Staff's methodology for the last six months of the 2006 Net Revenue Calculation Period and for future Net Revenue Calculation Periods.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

Interpretation of Disputed Tariff Language

In its November 2, 2006, Order, the Commission stated that it would consider evidence on the proper interpretation of the following language contained in the BPM Revenue Sharing Rider:

> Gross revenues from BPM Sales,
>
> Less
>
> Incremental Costs, defined as incremental costs associated with the BPM Sales, as determined by **a post event dispatch model that assigns the lowest cost generation to serve retail and cost-based wholesale load. The incremental costs shall include the** fuel costs, variable O&M costs, and **emission allowance costs as determined by the post event dispatch model**, the transmission costs associated with said sales, an allocation of wholesale business personnel costs,

> and the net impact of any hedges entered into on behalf of said transactions. (Emphasis added.)

The Commission invited testimony on the identity of the post event dispatch model referred to in the tariff, the meaning of the reference to the post event dispatch model, the manner in which the post event dispatch model operates, the appropriateness of the inputs to the post event dispatch model, whether the post event dispatch model has been modified during the period the tariff has been in effect, and other similar questions. Duke witnesses Hager and Johnson and Public Staff witness Maness addressed these questions in their prefiled testimony.

Ms. Hager testified that she was familiar with Duke's post event dispatch model -- how the model operates, how it is used for regulatory purposes, and what Duke intended when it referred to the model in the definition of BPM Net Revenues. Mr. Johnson testified that he used the incremental production cost inputs to the model in connection with his responsibilities for evaluating opportunities for BPM Sales. He further testified that he was responsible for acquiring emission allowances on behalf of Duke and provided information from independent price indices of settlement emission allowance market prices for inclusion in the model.

According to the Duke witnesses, the post event dispatch model is a computer program called Post Analysis and Cost Evaluation (PACE) that is used to assign incremental generation production costs to sales, including BPM Sales. It is an after the fact analysis of how Duke's system actually operated on a given day and is used to analyze the actual dispatch of generation and purchased power and the ranking of generation and purchased power resources based on cost. This information is then used to assign generation and purchased power resources to native load or BPM Sales, as appropriate, based on cost.

The witnesses explained that PACE is run on a weekly basis. The first step is to compile a base case based on total actual generation, sales, and purchases for the week. Key inputs include incremental fuel costs, variable operation and maintenance (O&M) costs, average and incremental heat rates, maximum and minimum unit generation capacity, start up costs, ramp rates, minimum start up and coast down times, and incremental emission allowance costs. The model stacks each generation resource by hour, including units dispatched and purchased power utilized, from least cost to highest cost, based on the incremental heat rate of each unit and the variable O&M, incremental fuel, and incremental emission allowance costs. It computes the cost of each BPM sale by sequentially assigning the most expensive generation resource first. The model algorithm is repeated for each sale in order to identify by unit the megawatt hours used to supply each BPM sale. Absent an operational issue requiring a unit to run out of dispatch order, PACE assigns Duke's retail and wholesale native load the lowest cost generation.

Ms. Hager testified that she drafted the language used in the tariff, which was written to reflect the method Duke was using to assign costs to BPM Sales. She stated that the "post event dispatch model" referred to in the tariff is the PACE model. According to Ms. Hager, it has been the Company's longstanding practice to assign costs to BPM Sales in a manner that is intended to prevent retail rates and reliability of service from being adversely affected by these types of sales. She stated that Duke has used the same methodology for determining the incremental cost of emission allowances since 2000 for purposes of (1) dispatching its units, (2) making economic decisions regarding entering into BPM Sales, (3) assigning generating resources to BPM Sales, and (4) determining the cost of emission allowances in connection with its South Carolina fuel filings where the cost of SO_2 allowances is recovered through the fuel clause. Further, since 2000, Duke has used replacement cost as determined by settled market prices reported by independent price indices to determine the incremental cost of emission allowances used in the PACE model. Under this methodology, emission allowance tons used by the Company's generating stations each month are assigned to BPM Sales based on the units assigned to BPM Sales and are priced out at replacement cost.

Ms. Hager testified that Duke proposed the BPM Rider as a voluntary rate reduction and incorporated into the Rider its own definition of BPM Net Revenues, an integral part of which is the use of replacement costs in arriving at emission allowance costs. She maintained that the use of replacement costs to measure the incremental cost of emission allowances is appropriate because it is consistent with the concept of holding retail ratepayers harmless from BPM Sales, if and when such sales take place, by assigning a higher cost for the allowances to BPM Sales and saving the lower cost allowances for retail cost of service. She stated that Duke believed and continues to believe that the most recent market prices are the best proxy for the cost of replacing emission allowances used in a given period and best reflect the incremental costs associated with BPM Sales. Finally, she stated that Duke never contemplated using either of the methodologies proposed by CUCA and the Public Staff in this proceeding.

With respect to holding retail ratepayers harmless from the effect of BPM Sales, Ms. Hager testified on cross-examination that Duke incurred approximately $8 million in emission allowance costs in 2005 and charged approximately $39 million in emission allowance costs to BPM Sales, but credited retail cost of service for the $31 million difference. Ms. Hager stated that, in doing so, the Company was giving those customers credit for the fact that the Company will have to replace those allowances in the future and that the higher cost would go into inventory. She further stated that this is essentially a timing issue, with Duke anticipating that it will have to replace those allowances at a higher cost than average inventory and giving credit to customers in retail cost of service now.

In response to questions from the Commission, Ms. Hager testified that the PACE model identifies the unit that is associated with a BPM sale and allows the Company to find out what cost was associated with that unit for that hour. She acknowledged that the various inputs have to be loaded into the model, that there is some subjective discretion as to how to input that data, and that the cost of emission allowances is not inherent in the model. With respect to the effect of inputting the actual cost of emission allowances into the PACE model, Ms. Hager stated that the model would still assign the highest cost generation to BPM Sales but that Duke's position is that doing so may not be assigning the lowest cost generation to retail sales in the long run because the Company would ultimately incur a higher cost that must be borne by retail customers. She also questioned whether, if the Company changed the use of replacement costs to the Public Staff's methodology for determining the incremental cost of emission allowances for purposes of the Rider, it would use the Public Staff's methodology for determining the incremental cost of emission allowances for the dispatch decision as well.[1]

[1] The Commission noted in its June 28, 2006 Order that the Public Staff is not opposed to Duke utilizing a different measure of cash flows in its pre-event decision analysis, but not in its measure of BPM Net Revenues.

Public Staff witness Maness testified that he was generally familiar with the PACE model, primarily from the Public Staff's review of fuel costs in connection with the Company's annual fuel proceedings. He stated that PACE is used by Duke to assign fuel cost to BPM Sales for purposes of those proceedings, with the highest-cost generating units and purchased power resources actually dispatched assigned to the Company's BPM Sales and the fuel cost associated with those resources (and thus those BPM Sales) determined on the basis of the actual monthly fuel cost booked for each of those resources. The fuel cost thus assigned to BPM Sales is deducted from total system fuel costs as part of the determination of the net fuel expense allocable to the Company's North Carolina retail ratepayers. Mr. Maness stated that the description of the model's operation in the testimony of Ms. Hager and Mr. Johnson is consistent with his understanding and that he had no reason to doubt the accuracy of the witnesses' testimony regarding whether changes had occurred in the model during the time the BPM Rider has been in effect.

With respect to the BPM tariff, Mr. Maness stated that he believes he initially read the language regarding the calculation of BPM Net Revenues prior to the issuance of the June 9, 2004 Order in this docket and that, having discussed the PACE model with Company personnel during the Public Staff's annual review of fuel proceedings and having discussed the Sharing Arrangement with other members of the Public Staff, he assumed that the term "post event dispatch model that assigns the lowest cost generation to serve retail and cost-based wholesale load" in the first sentence of the definition referred to the same PACE model that was used for determining the fuel costs related to BPM Sales. However, he interpreted the reference to "the post event dispatch model" in the second sentence to be only a general reference to the model and its determination of costs, rather than a reference to the specific valuation of inputs to the model, which, in his mind, would naturally be subject to review and adjustment by the Commission, if appropriate, throughout the period that the BPM Rider would be in effect. He stated that nothing in his reading of the tariff language at that time suggested to him that the acceptance by the Commission of the term "post-event dispatch model" (such as PACE) constituted Commission acceptance of any particular valuation method, including replacement costs, to determine the incremental emission allowance cost inputs.

Mr. Maness further testified that the use of the indefinite article in the first sentence of the Incremental Cost definition appears to allow incremental costs to be determined by any post event dispatch model that "assigns the lowest cost generation to serve retail and cost-based wholesale load" and that the use of the definite article in the second sentence appears to refer back to the model chosen in accordance with the first sentence. Also, as discussed extensively in the comments of the Public Staff, "incremental" is not synonymous with "replacement." Using replacement costs to determine the incremental cost of a resource is but one method that can be used to determine incremental costs for accounting and ratemaking purposes.

Mr. Maness also testified that, at the time of the approval of the Sharing Arrangement in June 2004, he was not aware that replacement costs were being used in PACE to determine the incremental costs of emission allowances associated with BPM Sales. He explained that there was no particular reason for him to have been aware of the valuation of emission allowances in the Company's use of PACE, as he was primarily familiar with the model through his review of fuel costs, and, since emission allowance expenses are not included in fuel costs in North

Carolina, the Public Staff did not focus on their valuation. He stated that, according to his recollection, he first became aware that Duke was using replacement costs to value emission allowances in the spring of 2005, at or about the time the Company filed its calculations for the BPM Rider it proposed to put in place July 1, 2005. Although he apparently received a data response from the Company in August 2004 stating that replacement costs were being used for this purpose, he did not recall noting the reference to the valuation of emission allowance costs at that time.

With respect to Duke's use of replacement costs for determining the cost of emission allowances for the purpose of dispatching its units, making economic decisions regarding entering into BPM Sales, assigning generating resources to BPM Sales, and determining the cost of emission allowances in connection with its South Carolina fuel filings, Mr. Maness testified that he believes he was informed of these uses of replacement costs during the BPM Rider review in either the spring of 2005 or the spring of 2006. He further testified that he had no reason to question Ms. Hager's and Mr. Johnson's testimony on this point, adding that his testimony and the Public Staff's comments in this docket have to do only with the incremental cost of emission allowances for purposes of the Rider, which is a separate ratemaking issue that is not dictated by these other uses of replacement cost or by the language of the Rider itself.

With respect to the appropriateness of using replacement costs for determining the incremental cost of emission allowances associated with BPM Sales for purposes of calculating the Rider, Mr. Maness referred to the Public Staff's verified comments in this docket containing an extensive discussion of why the Public Staff believes the use of replacement costs is inappropriate. According to Mr. Maness, the Public Staff continues to believe that its recommended methodology is more appropriate than that proposed by Duke. Unlike Duke's methodology, it is fully consistent with long-standing, Commission-accepted ratemaking principles in that it (a) uses the Company's actual expenses as a foundation for determining the rate and (b) adheres to the concept of preserving the lowest-cost emission allowances actually expensed for native load customers. Duke's methodology, on the other hand, results in the assignment of emission allowance costs to BPM Sales that were far greater than the costs the Company actually expensed for all sales in 2005, including costs for NO_x allowances that the Company did not incur at all. Finally, Duke's proposed methodology is inconsistent with its method for determining fuel costs related to BPM Sales for purposes of both the BPM Rider and its annual fuel cases. In both those instances, the Company uses the actual accounting costs experienced by its generating units, not replacement costs, to determine the amount of fuel expense assigned to BPM Sales.

Mr. Maness testified on cross-examination that, if BPM Sales continue to be treated as jurisdictional in Duke's next general rate case, assigning actual instead of replacement costs to allowances will result in more profits to flow back to retail customers, thus offsetting any additional emission allowance expense charged to North Carolina retail ratepayers. If BPM Sales are treated as nonutility operations, however, the question will arise as to compensation of utility operations under the transfer pricing provisions of Duke's Code of Conduct, in which case replacement cost could be considered a measure of market price.

In response to questions from the Commission, Mr. Maness agreed that the crediting mechanism described by Ms. Hager is a timing issue, at least conceptually. However, he stated that, in reality, how it plays out depends on variables such as the Clean Smokestacks Act, the operation of the units, the cost of emission allowances, and when allowances are purchased. With respect to Ms. Hager's testimony concerning expense accruals, Mr. Maness agreed that accruals are common and also pointed out that the Rider is inherently retrospective in looking at costs and prospective in setting rates, so that any $18 million error made in coming up with a proposed Rider for a period of time could require, as a result of Commission ordered correction, the Company to go back and reverse an accrual that had been based on the error.

The record shows that, from the very beginning, the disputed language of the tariff meant different things to Duke and the Public Staff.[1] Duke always intended both "a post event dispatch model that assigns the lowest cost generation to retail and cost-based wholesale customers" and "the post event dispatch model" to refer to the PACE model as it had been used for purposes other than the Rider, and to use replacement costs of emission allowances as inputs to the model in calculating BPM Net Revenues. While the Public Staff assumed that the tariff references were to the PACE model, it never recognized or supported Duke's treatment of emission allowance costs, reading the tariff to refer only to the model rather than the valuation of emission allowance cost inputs. The Commission believes both interpretations are permitted by the tariff language and rational from the parties' perspectives. On balance, however, the Commission finds and concludes that the evidentiary record on reconsideration supports the conclusion that its original interpretation of the term "Incremental Costs" was in error and that Duke's interpretation and intent regarding the meaning of that term should prevail. The credible evidence of record clearly indicates that Duke's intention from inception of the BPM Rider was that the incremental cost of emission allowances would be calculated using replacement cost as determined from independent market indices. Duke, of course, drafted the Rider, and the Company effectively asserts on reconsideration that, because the Sharing Arrangement was a voluntary rate reduction proposed under an exception to the rate freeze under the Clean Smokestacks Act, Duke's intention alone should control in the absence of fraud. On reconsideration, the Commission now agrees with Duke's credible testimony, evidence, and legal argument on this issue.[2] A contrary ruling by the Commission would violate the Clean Smokestacks Act in that the Company would be required, as shown by the undisputed evidence on reconsideration, to reduce rates to a greater degree than it voluntarily intended to do under G.S. 62-133.6(e)(2) when it initially filed the BPM Revenue Sharing Tariff.

Accordingly, for all of the foregoing reasons, the Commission concludes that the phase "emission allowance costs as determined by the post event dispatch model" in the BPM tariff is properly construed to mean the replacement cost of emission allowances associated with generation assigned by the PACE model to BPM Sales.

[1] In its November 2, 2006 Order, the Commission reiterated its authority to interpret a tariff that has been voluntarily filed and approved, but noted at page 3 that "during the rate freeze enacted by G.S. 62-133.6(e), a legally-erroneous interpretation of a voluntarily-filed tariff might violate the rate freeze provisions of the Clean Smokestacks Act in addition to contravening other provisions of North Carolina law." Accordingly, the Commission scheduled the matter for evidentiary hearing on the disputed tariff language that it might apply the principles of tariff construction set forth in Thrifty Call.

[2] While the Commission now finds Duke's legal argument to be determinative on the merits, the Commission continues to believe that the Public Staff has put forward the better policy arguments and has considered this fact in deciding to approve the Offer of Settlement.

Approval of Offer of Settlement

As noted in its November 9, 2006 Order, the Commission has been presented with a non-unanimous Offer of Settlement, which it may adopt as a decision on the merits if it "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 of the evidence presented." State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998).

In the Offer of Settlement, Duke has agreed to use the methodology proposed by the Public Staff and approved by the Commission in its June 28, 2006 Order for purposes of calculating BPM Net Revenues under the Sharing Arrangement for the period July 1, 2006, through December 31, 2006, of the 2006 Net Revenue Calculation Period and for future Net Revenue Calculation Periods (which, under the Sharing Arrangement, will most likely include all of calendar year 2007); the Public Staff has agreed to withdraw its opposition to the methodology used by Duke to determine the incremental cost of emission allowances for purposes of calculating BPM Net Revenues under the Sharing Arrangement for the 2005 Net Revenue Calculation Period and the period January 1, 2006, through June 30, 2006, of the 2006 Net Revenue Calculation Period; Duke has agreed to extend the Sharing Arrangement to provide for an additional Net Revenue Calculation Period ending the earlier of December 31, 2008, or the effective date of a Commission Order establishing new base rates and addressing the ratemaking treatment of revenues from BPM Sales; and (4) Duke and the Public Staff, without waiving the right to assert other positions with respect to the ratemaking treatment of BPM Sales (e.g., costs and revenues), have agreed to hold good faith discussions toward developing a joint proposal for sharing net revenues from BPM Sales on an ongoing basis for consideration by the Commission in Duke's next general rate case.

Both the Duke witnesses and the Public Staff witness maintained their respective positions regarding the disputed tariff language, while supporting the Offer of Settlement as a compromise acceptable to the parties. CUCA witness O'Donnell, on the other hand, criticized the Offer of Settlement as taking away a known quantity of $18 million that would otherwise go to struggling manufacturers today in return for the possibility that the Sharing Arrangement will be extended for one year. Mr. O'Donnell testified that prices in the bulk power markets are down significantly over the past year and that forward prices are showing a continued trend downward. As a result, Mr. O'Donnell stated, the substantial level of BPM profits Duke earned in 2005 is unlikely to continue for the rest of 2006 and through 2007, much less 2008.

Ms. Hager testified in rebuttal that CUCA strongly objected to the BPM Sharing Rider when it was proposed, arguing that the Rider did not sufficiently benefit CUCA's members, but, after receiving the benefits of the voluntary rate reduction for two years, suggests that Duke's original intent should be ignored and overridden based on the assertion that the manufacturing sector is still in need of relief. Ms. Hager stated that the nature of a settlement is that it seeks to strike a compromise between competing positions and suggested that the parties and the Commission consider how the Offer of Settlement compares to the possible outcomes of this proceeding. Stating Duke's belief that the grounds for its position in its Motion for Reconsideration have merit, Ms. Hager noted that Duke's position could prevail, either before the Commission or on appeal, and that by using the Public Staff's methodology for determining the incremental cost of emission allowances associated with BPM Sales for the second half of the calendar 2006 Net Revenue Calculation Period and for all calculation periods through the end of the BPM Sharing Arrangement, the Offer of Settlement increases the amount of BPM Net Revenues to be shared with industrial customers over the amount that would be shared if Duke's position prevails.

Ms. Hager further testified that, in reaching a fair compromise, June 30, 2006, is a reasonable point in time to transition from Duke's methodology to the Public Staff's methodology. She stated that this date generally coincides with the time the Public Staff developed its methodology and the time through which Duke had been using its own methodology for accruing its obligation to share BPM Net Revenues in its accounting records. Moreover, it was not until after the June 28, 2006, Order that Duke attempted to convert the Public Staff's methodology into a calculation.

Ms. Hager acknowledged that Duke's BPM Sales results are lower for 2006 than they were for 2005, but stated that Duke cannot guarantee any specific level of BPM Net Revenues for future Sharing Periods under the Rider, as wholesale power markets are volatile and BPM Sales, which by their nature are opportunistic transactions using temporary surplus generation capacity, are difficult to predict. With respect to Mr. O'Donnell's use of current forward prices to evaluate the reasonableness of the Offer of Settlement, Ms. Hager asserted that attempting to predict future BPM Net Revenues based on a snapshot of forward prices fails to consider the volatility of power markets. For example, Duke's analysis indicated that, when one compared forward prices for the PJM West Hub during the twelve months prior to September 2005 with actual prices for the period September 2005 through December 2005, forward prices for this period were $30 to $45 lower per megawatt-hour than the actual average on-peak settled price during the period. With respect to Mr. O'Donnell's suggestion that the days of wholesale power sales at $140 per megawatt-hour are behind us, Ms. Hager stated that power sales can and continue to be very high in specific hours. For example, PJM West real time locational marginal prices (LMP) for the week of July 30, 2006, showed 49 hours in which the settled hourly price was in excess of $140 per megawatt-hour with prices in some hours as high as $769 per megawatt-hour. Similarly, during the recent cold weather which occurred December 7 through 9, 2006, there were seven hours in which PJM West real time LMPs exceeded $140 per megawatt-hour. Ms. Hager stated that Duke strives to take advantage of such market opportunities when it has generation to sell, and the Rider and its potential extension under the Offer of Settlement provide customers an opportunity to share directly in the revenues Duke is able to achieve.

In his rebuttal testimony, Public Staff witness Maness took issue with certain assertions in Mr. O'Donnell's testimony regarding the Offer of Settlement. Mr. Maness explained that the Offer of Settlement does not provide for "extend[ing] the BPM revenue sharing period one year, through December 31, 2008," as stated by Mr. O'Donnell. Instead, it provides for an additional Net Revenue Calculation Period, extending from January 1, 2008, through December 31, 2008, and implicitly an additional Sharing Period of July 1, 2009, through June 30, 2010. The effective date of any intervening general rate case would only end the Net Revenue Calculation Period as of that effective date, but not eliminate the Sharing Period related to any Net Revenue Calculation Periods (or portions thereof) that had already occurred.

Moreover, Mr. Maness testified, the Offer of Settlement is not limited to "the possibility that the sharing arrangement will be extended for one year." Instead, since the Net Revenue Calculation Period will almost certainly extend through December 31, 2007, and the Sharing Period through June 30, 2009, the Offer of Settlement includes Duke's agreement to use the methodology proposed by the Public Staff for determining the incremental cost of emission allowances associated with BPM Sales, as approved by the Commission in its June 28, 2006, Order, for the Net Revenue Calculation Period(s) extending from July 1, 2006, through December 31, 2007, a total of 18 months. Thus, the Offer of Settlement represents a concession by Duke equal in terms of time to the agreement by the Public Staff to no longer oppose Duke's preferred methodology for the Net Revenue Calculation Period(s) extending from January 1, 2005, through June 30, 2006.

In reaching a decision on whether to approve or disapprove the Offer of Settlement, the Commission is mindful of the voluntary nature of the BPM tariff and the statutory context in which it was proposed. The Commission is also mindful of the fact that, although Duke was on notice as early as June 2005 that the Public Staff disagreed with the use of replacement costs to determine the incremental cost of emission allowances for purposes of the Rider, it was not until the spring of 2006 that the Public Staff proposed a specific alternative method to the Company, and it was not until June 28, 2006, that the Commission adopted that method and required it to be implemented with respect to the 2005 and subsequent Net Revenue Calculation Periods. Finally, the Commission is also mindful of the fact that it was not until the Company received the June 28, 2006 Order that it knew with certainty the magnitude of the effect of the Commission's decision on its share of BPM Revenues for the previous 18 months.

For the foregoing reasons, and because Duke and the Public Staff have, in good faith, both maintained very different understandings of the meaning of the disputed tariff language, the Commission believes that the Offer of Settlement is a just and reasonable resolution to the issues raised in the Company's motion for reconsideration. It is also an outcome that Duke has indicated it will voluntarily accept for purposes of G.S. 62-133.6(e)(2). In reaching this conclusion, the Commission notes that, at oral argument on August 29, 2006, Duke requested, by way of alternative relief, that the June 28, 2006 Order be permitted to operate only with respect to the Net Revenue Calculation Period beginning January 1, 2007, while the Public Staff suggested that making the Order prospective only with respect to Net Revenue Calculation Periods beginning January 1, 2006, would appear to achieve the result sought by the motion for reconsideration. The Commission might well have concluded, at that time, that making the Order prospective for the period July 1, 2006, through December 31, 2006, of the 2006 Net Revenue Calculation Period and for future Net Revenue Calculation Periods was a reasonable compromise and issued an Order to that effect. It is entirely within the Commission's authority to reach the same conclusion now.

Finally, the Commission notes that the benefits enjoyed by industrial customers whose rate schedules are subject to the Sharing Arrangement are not insubstantial under the present Rider as approved in this Order. The rate decrement in the first Rider was 0.1336¢/kWh and the rate decrement in the second Rider was 0.0322¢/kWh, both of which were based on BPM Sales for the 2004 Net Revenue Calculation Period. The rate decrement in the current Rider, for the 2005 Net Revenue Calculation Period, is 0.3702¢/kWh using Duke's methodology. The next Rider, for the 2006 Net Revenue Calculation Period, is expected to be larger than it would be under Duke's methodology because it will be based on six months of Net BPM Revenues calculated using the Public Staff's methodology; the Rider for the 2007 Net Revenue Calculation Period will be based entirely on the Public Staff's methodology. Of course, the magnitude of these Riders will ultimately depend on the volume and price of BPM Sales, but they will continue in effect at least until June 30, 2009, as a rate reduction that the Commission could not have compelled under the Clean Smokestacks Act and that has brought relief to Duke's industrial customers during difficult economic times.

Therefore, the Commission finds and concludes that the Offer of Settlement is just and reasonable to Duke, the Public Staff, and CUCA in light of all of the evidence presented.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's motion for reconsideration of the June 28, 2006 Order in this docket is hereby granted in part as follows:

A. That, beginning July 1, 2006, of the current Net Revenue Calculation Period, Duke shall calculate the BPM Rider in a manner consistent with the Public Staff's methodology and shall file the Rider with the Commission along with workpapers clearly setting forth the rate decrement reflected in the Rider, on or before May 1 for the Sharing Period beginning July 1 of the following year.

B. That the Net Revenue Calculation Period(s) established pursuant to the Sharing Arrangement approved in this docket shall end the earlier of December 31, 2008, or the effective date of a Commission Order establishing new base rates and addressing the ratemaking treatment of revenues from BPM Sales.

C. That, in the event the Commission issues an Order effective prior to December 31, 2008, affirming Duke's existing rates, the Sharing Arrangement shall be extended as provided in decretal paragraph 2 above, unless such order addresses the ratemaking treatment of revenues from BPM Sales.

D. That, without waiving the right to assert other positions with respect to the ratemaking treatment of BPM Sales (e.g., costs and revenues), Duke, the Public Staff, and CUCA are hereby authorized to hold good faith discussions toward developing a joint proposal for sharing net revenues from BPM Sales on an ongoing basis for consideration by the Commission in the Company's next general rate case.

2. That the June 28, 2006 Order is hereby rescinded.

3. That the Offer of Settlement filed on September 15, 2006, by Duke and the Public Staff is hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of February, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bb020507.01

DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 829
DOCKET NO. E-100, SUB 112
DOCKET NO. E-7, SUB 795

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 828 In the Matter of Duke Energy Carolinas, LLC – Investigation of Existing Rates and Charges Pursuant to Regulatory Condition No. 76 as Contained in the Regulatory Conditions Approved by Order Issued March 24, 2006, in Docket No. E-7, Sub 795 DOCKET NO. E-7, SUB 829 In the Matter of Duke Energy Carolinas, LLC – Investigation of Environmental Compliance Costs Pursuant to G.S. 62-133.6(d) and (f) DOCKET NO. E-100, SUB 112 In the Matter of Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 158 Entitled "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" and DOCKET NO. E-7, SUB 795 In the Matter of Application of Duke Energy Corporation for Authorization under G.S. 62-111 to Enter Into a Business Combination Transaction With Cinergy Corp. and for Approval of Affiliate Agreements under G.S. 62-153	)	ORDER APPROVING STIPULATION AND DECIDING NON-SETTLED ISSUES

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Chairman Edward S. Finley, Jr.; and Commissioners Robert V. Owens, Jr., Lorinzo L. Joyner, James Y.Kerr, II, Howard N. Lee, and William T. Culpepper, III

HEARD: Tuesday, August 14, 2007, at 6:30 p.m., Mazie Woodruff Center, 2100 Silas Creek Parkway, Winston-Salem, North Carolina

Wednesday, August 15, 2007, at 7:00 p.m., Charlotte-Mecklenburg Government Center, 600 E. Fourth Street, Charlotte, North Carolina

ELECTRIC – FILINGS DUE PER ORDER OR RULE

Tuesday, September 4, 2007, at 7:00 p.m., County Commissioners' Chambers, Durham County Government Administrative Center, 200 E. Main Street, Durham, North Carolina

Wednesday, September 19, 2007, at 7:00 p.m., Downstairs Courtroom, McDowell County Courthouse, Corner of Main and Court Streets, Marion, North Carolina

Thursday, September 20, 2007, at 7:00 p.m., Courtroom A, Macon County Courthouse, 5 W. Main Street, Franklin, North Carolina

Tuesday, October 16 and Wednesday, October 17, 2007, at 9:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

APPEARANCES:

For Duke Energy Carolinas, LLC:

Robert W. Kaylor, Law Offices of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 160, Raleigh, North Carolina 27603

Kodwo Ghartey-Tagoe, Lara S. Nichols, and Lawrence B. Somers, 526 South Church Street, EC03T, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Antoinette R. Wike, Gisele L. Rankin, Dianna Jessup, Kendrick Fentress, and William E. Grantmyre, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

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For the Carolina Utility Customers Association, Inc:

James P. West, West Law Offices, P.C., Post Office Box 1568, Raleigh, North Carolina 27602

For the Carolina Industrial Group for Fair Utility Rates III:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602-1351

For Wal-Mart Stores East, LP:

Rick D. Chamberlain, Behrens, Wheeler & Chamberlain, 6 N.E. 63rd Street, Suite 7400, Oklahoma City, Oklahoma 73105

ELECTRIC – FILINGS DUE PER ORDER OR RULE

BY THE COMMISSION: On March 9, 2007, in keeping with Regulatory Condition No. 76 set forth in its Order dated March 24, 2006, in Docket No. E-7, Sub 795 (the Merger Order), the Commission issued its Order Initiating Proceedings, Instituting Investigations, and Setting Hearing, in which the Commission opened Docket Nos. E-7, Subs 828 and 829 as consolidated dockets for the purposes of initiating an investigation of the rates and charges of Duke Energy Carolinas, LLC (Duke or the Company) pursuant to G.S. 62-130(d), 62-133, and 62-136(a) and initiating an investigation of the environmental compliance costs of the Company as required by G.S. 62-133.6(d). In that Order, the Commission directed Duke, not later than May 15, 2007, to either (1) file a general rate case pursuant to G.S. 62-137 or (2) show cause why its existing rates and charges should not be found unjust and unreasonable and, in either case, to file by the same date a Rate Case Information Report using Form E-1. That Order also declared the proceedings in Docket No. E-7, Sub 828 to be a general rate case; declared the test period to be the 12-month period ending December 31, 2006; established the hearing schedule for the consolidated proceedings; ordered the Company to file testimony and exhibits supporting its proposals in Docket No. E-7, Sub 829 pursuant to G.S. 62-133.6(i) by May 15, 2007; and established a schedule for discovery and for the filing of testimony and exhibits by intervenors and the Public Staff of the North Carolina Utilities Commission (Public Staff) and rebuttal testimony and exhibits by the Company. The May 15, 2007 due date was subsequently extended to June 1, 2007.

Petitions to intervene were filed by the Carolina Industrial Group for Fair Utility Rates III (CIGFUR III) on March 13, 2007, and by the Carolina Utility Customers Association, Inc. (CUCA) on March 19, 2007. On March 16 and 21, 2007, respectively, the Commission entered Orders granting the petitions of CIGFUR III and CUCA. The North Carolina Attorney General's Office gave notice of its intervention on May 30, 2007. The intervention and participation of the Attorney General was recognized pursuant to G.S. 62-20. On August 13 and 21, 2007, respectively, Wal-Mart Stores East LP (Wal-Mart) and the North Carolina Municipal Power Agency No. 1 (NCMPA) filed petitions to intervene. On August 17, 2007, the Commission granted Wal-Mart's petition to intervene. On August 24, 2007, Duke filed objections to the NCMPA's petition to intervene, and on September 13, 2007, the Commission denied the petition to intervene by the NCMPA. The intervention and participation of the Public Staff was recognized pursuant to G.S. 62-15 and Commission Rule R1-19(e).

On May 4, 2007, the Commission issued an Order consolidating Docket No. E-100, Sub 112 with these dockets for the purpose of receiving evidence concerning the issue of Duke's compliance with Commission Rule R8-27 in connection with the accounting treatment that it proposed for the purpose of implementing Statement of Financial Accounting Standards No. 158 (SFAS No. 158).

On June 1, 2007, Duke filed its Application for Authority to Adjust and Increase its Rates and Charges, along with a Form E-1 Rate Case Information Report and the direct testimony and exhibits of James E. Rogers; Ellen T. Ruff; Robin T. Manning; John J. Roebel; Henry B. Barron, Jr.; Lynn J. Good; Steven M. Fetter; Dr. James H. Vander Weide; Dwight L. Jacobs; Jane L. McManeus; Carol E. Shrum; Jeffrey R. Bailey; and John J. Spanos.

On June 21, 2007, the Commission issued its Order Scheduling Public Hearings and Requiring Public Notice Thereof.

On August 2, 2007, the Commission entered an Order consolidating the Company's application in Docket No. E-7, Sub 831 for approval of the "Save-a-Watt" approach to energy efficiency (EE) with these dockets. On August 14, 2007, Duke filed a motion for reconsideration seeking to have Docket No. E-7, Sub 831 severed from these dockets. After the enactment of North Carolina Session Law 2007-297 (Senate Bill 3), the Commission issued its Order bifurcating Docket No. E-7, Sub 831 from these dockets on August 31, 2007.

On September 13, 2007, the Public Staff proposed by letter that the first audit report by the independent auditor, The Liberty Consulting Group (Liberty), due on October 1, 2007, be entered into evidence in this proceeding, along with the credentials of John Antonuk, Liberty's President, who would be the witness for Liberty. On September 20, 2007, the Commission entered an Order granting the Public Staff's request and establishing a date certain for Mr. Antonuk's testimony. The Liberty Audit Report was filed on October 1, 2007.

On September 4, 2007, Duke filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural Orders.

Between August 14, 2007, and September 20, 2007, public hearings were held in Winston Salem, Charlotte, Durham, Marion, and Franklin for the purpose of receiving public testimony.

On September 10, 2007, Duke filed the supplemental direct testimony of James E. Rogers, Jeffrey R. Bailey, and Carol E. Shrum.

On October 5, 2007, the parties filed an Agreement and Stipulation of Partial Settlement (Stipulation) setting forth areas of agreement and nonagreement among all of the parties of record (the Stipulating Parties). On the same date, Duke filed the supplemental testimony of Ellen T. Ruff; the Public Staff filed the direct testimony of Darleen P. Peedin, Michael C. Maness, Jack L. Floyd, and Dr. Ben Johnson; and CIGFUR III filed the direct testimony of Nicholas Phillips, Jr. CUCA and Wal-Mart filed separate statements in support of the Stipulation.

On October 11, 2007, Duke filed the direct testimony of Barbara G. Yarbrough and the rebuttal testimony of Ellen T. Ruff, Jeffrey R. Bailey, Dr. Julius A. Wright, and Nancy J. Horsley.

Also, on October 11, 2007, the Commission issued its Pre-Hearing Order, which designated the times and place of the hearing and the order of witnesses, fixed the times for filing post-hearing briefs and proposed orders, and directed Duke to file exhibits based on the Stipulation setting out the settled position before the additional litigated issues.

At the request of Duke and the Public Staff, respectively, the Commission on October 12, 2007, entered an Order excusing Company witnesses James E. Rogers; Robin E. Manning; John J. Roebel; Henry B. Barron, Jr.; Lynn J. Good; Steven M. Fetter; Dr. James H. Vander Weide; and John J. Spanos and Public Staff witness Dr. Ben Johnson from appearing at the hearings, subject to recall by the Commission if needed. In that Order, the Commission also notified the parties that a witness from the North Carolina Department of Environment and Natural Resources (DENR) would testify at the hearing regarding Duke's compliance with the emissions reduction provisions of the Clean Smokestacks Act.

On October 15, 2007, the Attorney General's Office filed a Statement of Position recommending certain changes to Duke's Service Regulations with respect to the definition of "customer" and the provisions relating to the denial and discontinuance of service. Also, on October 15, 2007, the Public Staff filed the affidavit of Elise Cox regarding amounts associated with additional expense items that will be defined as "cost of fuel and fuel-related costs" under the amendments to G.S. 62-133.2 enacted as part of Senate Bill 3, and Duke filed the exhibits required by the Commission's Pre-Hearing Order of October 11, 2007, showing the financial effects of the settlement reflected in the Stipulation before consideration of the additional litigated issues.

The public hearings were held as scheduled. The following public witnesses appeared and testified:

Winston-Salem:	Kristie Reid, Robin Rhyne, Larry Law, and Sandra Thomas
Charlotte:	Jack Copeland, Jr., James Howard, Donny Hicks, Ron Smidt, and John Nims
Durham:	Ted Conner and Bill Kalkaf
Marion:	Dave Hart, Tony Young, David Johnson, and Roxanne D. Boyd
Franklin:	Verlin Curtis, Dan Roland, Jan Unger, Roy Sargent, Narelle Kirkland, and David Johnson

The matter came on for hearing in Raleigh on October 16, 2007. All prefiled testimony and exhibits filed in these dockets were admitted without objection. All parties agreed to waive cross-examination on the prefiled direct testimony with respect to the settled issues. DENR presented the testimony of Brock Nicholson, Director of the Air Quality Division, regarding Duke's compliance with the emissions limitation provisions of the Clean Smokestacks Act. Duke then presented a panel consisting of Ellen T. Ruff, Carol E. Shrum, Jeffrey R. Bailey, and Barbara G. Yarbrough, which summarized the terms of the Stipulation and answered questions from the Commission regarding the Stipulation. Witness Yarbrough also answered questions and was cross-examined concerning the issues raised by the Attorney General's Office in its Statement of Position. Duke presented the rebuttal testimony of its witnesses Ellen T. Ruff and Dr. Julius A. Wright. The Public Staff presented the testimony of Elise Cox, Darleen P. Peedin, and Michael C. Maness. The direct testimony of Public Staff witness Jack L. Floyd and CIGFUR III witness Nicholas Phillips, Jr., and the rebuttal testimony of Company witnesses Jeffrey R. Bailey and Nancy J. Horsley were admitted into evidence by stipulation.

On October 26, 2007, the Commission issued a Post-Hearing Order requiring responses to its requests for additional information in the form of verified late-filed exhibits and the briefing of certain issues. Between October 26 and November 1, 2007, Duke filed its responses to the inquiries posed by the Commission in its Post-Hearing Order. On November 1, 2007, the Public Staff filed the supplemental affidavit and exhibit of Elise Cox. On November 5, 2007, Duke, the Public Staff, the Attorney General, and CIGFUR III filed their briefs and/or proposed orders and CUCA filed a letter in support of the Stipulation.

On November 29, 2007, the Commission entered a Notice of Decision and Order in these dockets. By that Notice of Decision and Order, the Commission gave notice that it would thereafter enter an Order in these dockets which would:

ELECTRIC – FILINGS DUE PER ORDER OR RULE

1. Approve the Stipulation filed by Duke, the Public Staff, the Attorney General, CUCA, CIGFUR III, and Wal-Mart on October 5, 2007, subject to the additional decisions set forth below.

2. Disallow Duke's proposed adjustment to increase test-year operating expenses by $39,925,000 to eliminate gross merger savings which were actually experienced during the last nine months of the test year and, instead, approve the Public Staff's proposed adjustment to test-year operating expenses to reflect an annualized level of merger savings minus fuel savings in the amount of $46,241,000.

3. Announce that the Commission would, pursuant to G.S. 62-80, reconsider one provision of the Merger Order entered in Docket No. E-7, Sub 795 on March 24, 2006. The Commission stated that it would specifically reconsider that provision in Regulatory Condition No. 76 (as discussed in conjunction with Finding of Fact No. 37 in the Merger Order and the Evidence and Conclusions in support thereof) which provides that:

> . . . Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. . . .

The Commission further stated that it had preliminarily concluded that the provisions of the Merger Order will not produce a fair sharing of the benefits of the estimated merger savings between ratepayers and shareholders and that, for that reason, Duke should be authorized to implement a 12-month rate increment rider to collect $80,459,000 from its North Carolina retail customers for the benefit of its shareholders. This amount represents 58% of the annualized level of gross merger savings of $46,241,000 reflected in rates in this proceeding for the next three calendar years (2008, 2009, and 2010). [$46,241,000 gross merger savings per year, times 0.58, times 3 years, equals $80,459,000].

4. Conclude that G.S. 62-133.6(e), the rate freeze provision of the Clean Smokestacks Act, does not apply to GridSouth costs incurred prior to June 2002, and does not prevent the Commission from approving a deferral and amortization of such costs at this time. Therefore, the Commission will approve a 10-year amortization of the costs in the amount of $29,059,000 incurred by Duke in developing the proposed GridSouth Regional Transmission Organization. The amortization will begin in June 2002, and $2,906,000 will be included as an operating expense in Duke's cost of service for purposes of this case. The Company will not be allowed to recover carrying charges which accrued after June 2002, or a return on the unamortized balance of its GridSouth costs for ratemaking purposes in this case.

5. Approve establishment of a regulatory asset in Account No. 182.3 by Duke Energy Corporation with respect to Duke's apportioned share of the funded status of pension and OPEB plan obligations as part of its compliance with SFAS No. 158 and request the Public Staff to examine and evaluate Duke's pension and OPEB plan funding practices and file a detailed report with the Commission setting forth its findings, conclusions, and recommendations. The Order will also authorize the Public Staff, in its discretion and as it

deems advisable and necessary, to engage an independent accounting or consulting firm to conduct the examination and evaluation or provide consulting assistance to the Public Staff.

6. Deny the Attorney General's request for amendments to Duke's Service Regulations.

7. Defer consideration of changes to Rider IS (Interruptible Power Service) to Docket No. E-7, Sub 831, and transfer to that docket, in addition to the consideration of the new programs proposed by Duke, the issue of what changes, if any, are appropriate to existing demand side management (DSM) and EE programs, such as Rider IS.

8. Conclude that no portion of any Environmental Compliance Costs directly assigned, allocated, or otherwise attributable to another jurisdiction pursuant to Section 7, Paragraph D of the Stipulation shall be recovered from North Carolina retail customers, even if recovery of those costs is disallowed or denied, in whole or in part, in another jurisdiction.

9. Require Duke to credit all future nuclear property insurance policy distributions to Account 228.1 unless specifically authorized by the Commission to change such accounting practice.

10. Approve a rate reduction of $286,924,000 in annual non-fuel base revenues effective January 1, 2008.

On December 5, 2007, the Commission entered an Order granting an extension of time until Friday, December 14, 2007, for Duke to file the rate schedules required by the Notice of Decision and Order.

On December 12, 2007, Duke filed Motion for Leave to Implement a 12-month increment rider associated with merger savings, consistent with the Notice of Decision and Order, on January 1, 2008, subject to refund.

On December 14, 2007, Duke filed the rate schedules required by the Notice of Decision.

On the same date, Duke filed a letter with the Commission setting forth Duke's response to the service issues presented by witness Roy Sargent at the public hearing held on September 20, 2007, in Franklin, North Carolina.

On December 17, 2007, the Commission entered an Order Requesting Comments on Rate Schedules in these dockets, in which the Commission provided all parties with an opportunity to file comments on the rate schedules filed by Duke on December 14, 2007. On December 19, 2007, the Commission entered an Order Granting Oral Motion for Extension of Time extending the time within which the parties were allowed to file comments on Duke's proposed rate schedules.

WHEREUPON, the Commission now makes the following

FINDINGS OF FACT AND CONCLUSIONS

Jurisdiction

1. Duke Energy Carolinas, LLC (Duke or the Company) is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. Duke 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 is a wholly-owned subsidiary of Duke Energy Corporation (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 public utilities operating in North Carolina, including Duke, under Chapter 62 of the General Statutes of North Carolina.

3. Duke is lawfully before the Commission based upon its Application for a general increase in its retail rates pursuant to G.S. 62-133 and 62-137 and on its presentation of its environmental plan and compliance costs under the North Carolina Clean Smokestacks Act, particularly G.S. 62-133.6(i).

4. The appropriate test period for use in this proceeding is the 12 months ended December 31, 2006, with appropriate adjustments.

The Stipulation – General

5. Duke, by its Application and testimony and exhibits filed in this proceeding, sought an increase of $140,239,000 or 3.6% in its annual non-fuel revenues from its North Carolina retail electric operations.

6. Duke submitted evidence in this case with respect to revenue, expenses, and rate base using a test period consisting of the 12 months ended December 31, 2006. The Stipulation is based upon the same test period.

7. On October 5, 2007, the Stipulating Parties filed a Stipulation, setting forth areas of agreement and nonagreement between all of the Stipulating Parties. The Stipulation executed by Duke, the Public Staff, the Attorney General's Office, CUCA, CIGFUR III, and Wal-Mart is unopposed by any party. Thus, the Stipulation is a settlement of all matters in these dockets except for those issues, separately addressed in this Order, with respect to which the Stipulating Parties were unable to agree.

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 fair and reasonable under the circumstances of this proceeding and should be approved, subject to the additional decisions set forth in this Order. The specific terms of the Stipulation are addressed in the following findings of fact and conclusions.

ELECTRIC – FILINGS DUE PER ORDER OR RULE

The Stipulation – Rates

9. The Stipulation provides for a net reduction of $233,000,000 in Duke's annual non-fuel revenues from its North Carolina retail electric operations. The Stipulating Parties agree that this revenue reduction will result in Company rates that are just and reasonable, subject to the Commission's decision on the issues about which the Stipulating Parties have not agreed. To achieve this reduction, Duke will adjust its North Carolina retail base rates to produce annual revenues of $3,738,696,000 from its North Carolina retail operations. The Stipulating Parties agree that these revenues are intended to provide Duke, through sound management, the opportunity to produce an overall rate of return of 8.57% on a jurisdictional rate base of $7,833,049,000. This overall rate of return is derived from Duke's long-term debt cost of 5.83% and a rate of return of 11% on the common equity component of a capital structure consisting of 47% long-term debt and 53% common equity. The Stipulation provides for allocation of the $233,000,000 rate reduction among the rate classes as set forth in Paragraphs 2D-E of the Stipulation, based upon the billing units recorded in the test year and adjusted for the effects of weather and customer growth, also as set forth in Paragraph 2D of the Stipulation.

10. The Commission has reviewed the Stipulation's provisions for an annual non-fuel revenue decrease of $233,000,000 and finds and concludes that this reduction in the level of base rates to be paid by Duke's North Carolina retail customers, resulting in an overall rate of return of 8.57% on jurisdictional rate base and a return on common equity (ROE) of 11% using a capital structure of 47% long-term debt and 53% common equity is just and reasonable, subject to the Commission's decisions on the issues about which the Stipulating Parties have not agreed.

11. The Stipulation provides that Duke's rates resulting from this proceeding will be designed to ensure that the industrial class receives a 12.7% decrease, the residential class receives a 3.85% decrease, and the general service class receives a decrease of 7.34% on the General schedule and 5.05% on the OPT–General schedule. The Commission finds and concludes that this allocation of the revenue decrease among the rate classes as set forth in Paragraph 2E of the Stipulation is just and reasonable, subject to the Commission's decisions on the issues about which the Stipulating Parties have not agreed.

12. The Stipulation provides for the transition of the Company's Nantahala Area residential customers to the regular Duke residential schedules RS or RE, giving Nantahala nonresidential customers the option to migrate to comparable Duke schedules, and certain other changes in the Nantahala rate schedules, Service Regulations, and jurisdictional reporting and accounting as more fully described in Paragraphs 3A-E of the Stipulation. The Commission finds and concludes that the provisions in the Stipulation regarding the transition of Duke's Nantahala Area customers to regular Duke rate schedules are just and reasonable and should be approved.

13. The Stipulation provides for a base fuel factor of 1.7371¢/kWh, including gross receipts tax, or 1.6812¢/kWh, excluding gross receipts tax, which the Commission finds and concludes is just and reasonable for purposes of this proceeding. The Commission finds and concludes that the following North Carolina retail amounts included in test period expenses will constitute "fuel related costs" upon the effective dates of North Carolina Session Law 2007-397

(Senate Bill 3) for the purpose of appropriately addressing these costs in future proceedings: (1) costs of reagents consumed in reducing or treating emissions under G.S. 62-133.2(a1)(3) of $3,174,863 or 0.005750277¢/kWh; (2) non-capacity purchase power costs other than fuel under G.S. 62-133.2(a1)(4) of $29,325,989 or 0.053114904¢/kWh; and (3) net gains on coal by-product sales under G.S. 62-133.2(a1)(9) of $3,694,333 or 0.006691134¢/kWh.

14. The Stipulation provides that Duke's rates agreed to in the Stipulation shall be deemed to include 90% of the net revenues from its Bulk Power Marketing (BPM) transactions and 100% of the net revenues from its non-firm point-to-point transmission services experienced in the test year. The Stipulation further provides for a true-up rider to adjust this amount annually on an across-the-board kWh usage basis for all classes of customers. The base rates established in this proceeding include (a) North Carolina retail BPM Net Revenues of $35,471,000 (or 0.0642¢/kWh, excluding gross receipts tax), which consists of 90% of the North Carolina retail portion (allocated on the basis of megawatthour sales) of BPM Net Revenues earned during the test year and (b) Non-Firm Transmission Revenues of $3,697,000 (or 0.0067¢/kWh, excluding gross receipts tax), which consists of 100% of the North Carolina retail portion (allocated on the basis of transmission plant) of Non-Firm Transmission Revenues earned during the test year. Paragraphs 5A-D of the Stipulation set forth the details of this arrangement. The Commission finds and concludes that these provisions of the Stipulation are just and reasonable.

15. The Stipulating Parties agreed that construction work in progress (CWIP) expenditures for the new Cliffside generating unit incurred as of August 31, 2007, should not be included in Duke's rate base for purposes of this proceeding. The Commission finds and concludes that this provision of the Stipulation is just and reasonable. Furthermore, the total amount of stipulated rate base agreed to by the Stipulating Parties does not include any CWIP. Therefore, the Commission finds and concludes that it is appropriate not to include any CWIP in rate base for purposes of this proceeding.

16. Duke based its filing in this case on the Summer Coincident Peak (SCP) allocation methodology for both jurisdictional and class allocations. The Stipulation provides that Duke may continue to use that methodology, but that the Commission's decision to approve this component of the Stipulation for purposes of this proceeding will not establish a precedent for future general rate cases, and the Company will continue to file annual cost of service studies based on both the SCP and the Summer-Winter Peak and Average (SWPA) methodologies. The Commission finds and concludes that this provision is just and reasonable.

17. The Stipulation provides that Duke's depreciation rates set forth in Spanos Exhibit 1, entitled "Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2003", are appropriate for Duke to use in this proceeding and in recording depreciation expense and accumulated depreciation until further Order of the Commission. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

18. The Stipulation provides that Duke's system nuclear decommissioning costs in the amount of $48.3 million approved in the Commission's Order dated July 29, 2005, in Docket

No. E-100, Sub 56, are appropriate for the Company to use and include in the cost of service in this proceeding. The $48.3 million figure is a total-company amount; the North Carolina retail amount is $33.8 million. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

19. Regarding Duke's existing demand side management (DSM) and energy efficiency (EE) programs, the Stipulation provides that these programs shall continue under the same terms and conditions as are reflected in the Company's existing tariffs (with the exception that the water heating load control provision in Rider LC should be canceled effective January 1, 2008) unless the Commission rules in Docket No. E-7, Sub 831 that the programs should be canceled. The Stipulation also contains the following provisions with respect to these programs:

(a) The rates approved in this proceeding shall be considered to include an across-the-board levelized terminating rider, including a return on the unamortized balance, in the amount of 0.0140¢/kWh (excluding gross receipts tax), that will allow the Company to recover over five years the balance in Duke's DSM deferred account as of December 31, 2007. The rider is subject to adjustment resulting from changes in the Company's approved cost of capital in a subsequent general rate case during the rider's life. The rider will terminate on December 31, 2012, and the Company's rates shall then be reduced accordingly, on an across-the-board basis.

(b) The rates approved in this proceeding shall be considered to include $15,555,000 of North Carolina retail DSM costs, or 0.0282¢/kWh (excluding gross receipts tax), consisting of load management credits, interruptible service credits, and standby generation payments associated with existing DSM programs.

(c) The DSM deferred account, net of the December 31, 2007 balance, will continue to track the difference between (i) the actual costs of the Company's existing DSM programs, incurred on and after January 1, 2008, and (ii) the amount included in base rates for those programs on a cents per kWh basis. The cost deferral of existing DSM programs will continue to be subject to the provisions of the Commission-approved stipulations in Docket Nos. E-7, Sub 487, E-100, Sub 64, and E-100, Sub 75. A return equal to the overall rate of return (net of income tax) resulting from this rate proceeding will be added to the deferral account on a monthly basis and compounded annually.

(d) The Commission should establish an adjustable rider (which would be called the Existing DSM Program Rider, or EDPR), through which the balance in the Company's DSM deferral account (net of the December 31, 2007 balance) can be trued up in rates on a periodic basis. The deferral account balance would be determined as of each December 31, beginning December 31, 2008. The Company would be required to file its proposed EDPR on April 1 of each year beginning in 2009, to become effective for one year beginning July 1 of that year. Each EDPR must be approved by the Commission before becoming effective. The amount of each year's EDPR shall be distributed to all customer classes on the basis of estimated MWh sales for the period in which the EDPR is effective (July 1 through June 30).

(e) A special provision should be established by the Commission's Order in this proceeding that will allow the EDPR and the DSM deferral account to be modified or eliminated by Commission Order in Docket No. E-7, Sub 831 or Docket No. E-100, Sub 113, so that the EDPR and the deferral account can be appropriately adjusted to reflect the effects of those Orders on the recovery of Duke's DSM and EE costs.

The Commission finds and concludes that these provisions of the Stipulation are just and reasonable.

20. The Stipulation provides for a number of changes in Duke's rate design and Service Regulations, which are set out in detail in Paragraph 10 and Exhibit A of the Stipulation. The Commission finds and concludes that the rate design and Service Regulations proposed by the Company in its Application and in its testimony and exhibits filed in this proceeding, as modified by the changes agreed upon in the Stipulation, are just and reasonable, subject to the additional decisions set forth below.

21. Under Paragraph 14 of the Stipulation, the Stipulating Parties agree that it remains prudent and reasonable for Duke to record its policy distribution credits for nuclear property insurance to its nuclear insurance reserves account in order to provide possible funding for deductibles in the case of claims related to the Company's nuclear facilities or retrospective premium adjustments relating to claims against the facilities of other insured parties. The Stipulating Parties also agree that the balance in the Company's nuclear property insurance reserve account is currently appropriate and that the treatment of that balance as a rate base deduction in this proceeding is reasonable.

22. The Commission finds and concludes that Paragraph 14 of the Stipulation is reasonable and should be approved. The balance in the Company's nuclear insurance reserve account at the end of the test year was $173 million on a total-company basis and $122 million on a North Carolina retail basis. Duke shall credit all future nuclear property insurance policy distributions to Account 228.1, Accumulated Provision for Property Insurance, unless it is specifically authorized by the Commission to change such accounting practice.

23. Consistent with Paragraph 18 of the Stipulation, the Commission finds and concludes that the overall quality of electric utility service provided by Duke to its North Carolina retail customers is good.

24. Under Paragraph 19 of the Stipulation, Duke agrees not to oppose a petition by the Public Staff that the Commission review and modify the Company's Extra Facilities Charge prior to the Company's next general rate case. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

25. The Stipulation provides that it is appropriate for Duke to include an adjustment to the cost of service to normalize storm restoration costs for the test period in this proceeding. The Stipulating Parties reserved the right to oppose a request by the Company to defer and amortize future storm restoration costs on the grounds that the request is inconsistent with this normalization. The amount of normalized storm restoration costs included in the cost of service in this proceeding

on a North Carolina retail jurisdictional basis is $29,100,000. The Commission finds and concludes that this provision of the Stipulation is just and reasonable.

26. The Commission finds and concludes that it is just and reasonable to include a North Carolina retail amount of net uncollectible expense of $7,510,000 in Duke's test-period operating revenue deductions in this proceeding.

The Stipulation – Clean Smokestacks Act Compliance

27. The Stipulating Parties agreed that they will not challenge as unjust, unreasonable or imprudent Duke's expenditures through December 31, 2006, for emission controls required by the Clean Smokestacks Act (Environmental Compliance Costs) in the amount of $901,380,485. The Commission finds and concludes, based on the evidence of record, that these costs were reasonably and prudently incurred.

28. The Commission finds and concludes that, as of December 31, 2007, Duke will have amortized pursuant to G.S. 62-133.6(b) a total of $1,050,000,000 in Environmental Compliance Costs, as provided in the Stipulation.

29. The Stipulation eliminates $225.2 million of Environmental Compliance Cost amortization from the test-period cost of service. The Stipulating Parties agree that they will not contest the inclusion in rate base of all prudent and reasonable unamortized Environmental Compliance Costs as the projects are closed to plant in service, with such Environmental Compliance Costs being allocated among all jurisdictions and all customer classes. The Commission finds and concludes that this treatment is just and reasonable, but makes no finding at this time as to the reasonableness or prudence of any such unamortized Environmental Compliance Costs. No portion of any Environmental Compliance Costs directly assigned, allocated, or otherwise attributable to another jurisdiction pursuant to Paragraph 7D of the Stipulation shall be recovered from North Carolina retail customers, even if recovery of those costs is disallowed or denied, in whole or in part, in another jurisdiction.

30. Duke's actual and proposed modifications and permitting and construction schedule are adequate to achieve the emissions limitations set out in G.S. 143-215.107D.

The Stipulation – SFAS No. 158 Issue

31. Under Paragraph 8 of the Stipulation, Duke Energy Corporation (Duke Energy) proposes to establish a regulatory asset[1] in Account No. 182.3, Other Regulatory Assets, with respect to Duke's apportioned share of the funded status of pension and other postretirement benefit (OPEB) plan obligations as part of its compliance with the Financial Accounting Standards Board's (FASB's) SFAS No. 158, entitled "Employers' Accounting for Defined

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[1] Based on information contained in Duke's November 1, 2007 filing, which was made in response to the Commission's Post-Hearing Order, the total amount of the regulatory asset recorded on Duke Energy's books attributable to Duke, at December 31, 2006, was $550.7 million on a total-company basis. On a North Carolina retail basis, such amount was $385.4 million.

Benefit Pension and Other Postretirement Plans." Because of the materiality[1] and complexity of this issue, the Commission is of the opinion, and so finds and concludes, that the entire matter of pension and OPEB costing and funding from the standpoint of their impact and potential impact on rates should be further examined and evaluated, including examination and evaluation of the interrelationship, if any, that may exist between (a) the amounts of pension and OPEB costs included in the test-period cost of service; (b) the amounts of pension and OPEB costs actually charged to expense and capitalized annually; and (c) the amount of funding actually contributed to the pension trust fund on an annual basis. Therefore, the Commission finds and concludes that this provision of the Stipulation should be approved on a provisional basis, pending completion of the Commission's further review.

The Stipulation – Independent Audit Report

32. With respect to the independent audit conducted by The Liberty Consulting Group (Liberty) pursuant to Regulatory Condition No. 32 of the Commission's Merger Order, the Stipulating Parties recommend no adjustment to Duke's cost of service in this proceeding as a result of the Company's affiliate transactions. The Commission agrees, and finds and concludes, that no such adjustment is required at this time. Further, the Commission finds and concludes that all matters related to Liberty's final audit report, filed on October 1, 2007, should be bifurcated from this proceeding and will be addressed by the Commission by further Order.

Issue Not Settled by the Stipulation - Merger Savings

33. It is appropriate to reverse the Company's merger savings adjustment to increase operations and maintenance expenses (O&M) by $39,925,000 and to further reduce expenses to reflect the annualization of merger savings, net of fuel, as recommended by the Public Staff. In addition, the Commission will, pursuant to G.S. 62-80, reconsider one provision of the Merger Order entered in Docket No. E-7, Sub 795 on March 24, 2006. The Commission will specifically reconsider that provision in Regulatory Condition No. 76 (as discussed in conjunction with Finding of Fact No. 37 in the Merger Order and the Evidence and Conclusions in support thereof) which provides that:

> . . . Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. . . .

The Commission has preliminarily concluded that the provisions of the Merger Order will not produce a fair sharing of the benefits of estimated merger savings between ratepayers and shareholders and that, for that reason, Duke should be authorized to implement a 12-month rate increment rider to collect $80,459,000 from its North Carolina retail customers for the benefit of its shareholders. This amount represents 58% of the annualized level of gross merger savings of $46,241,000 reflected in rates in this proceeding for the next three calendar years (2008, 2009, and 2010).

[1] Regarding the amounts of pension and OPEB costs included as expenses in the 2006 test-period cost of service, Duke, in its Late-Filed Exhibit No. 10, filed on October 26, 2007, reported that such amounts were $31.2 million and $19.2 million, respectively, on a North Carolina retail basis.

Issue Not Settled by the Stipulation - GridSouth

34. The Commission finds and concludes that it is appropriate to include $2,906,000 as an operating expense in Duke's cost of service to amortize the North Carolina retail portion of its investment in GridSouth incurred prior to the end of June 2002, over a 10-year period beginning June 2002.

Issue Not Settled by the Stipulation – Rider IS

35. The Commission finds and concludes that Rider IS (Interruptible Power Service) should be continued in its present form until the Company's request to discontinue Rider IS is considered in Docket No. E-7, Sub 831. The consideration of what changes, if any, are appropriate to existing DSM and EE programs, including Rider IS, should be deferred and transferred to Docket No. E-7, Sub 831.

Issue Not Settled by the Stipulation - Service Regulations

36. The Commission finds and concludes that Duke's Service Regulations, attached as Exhibit A to the Stipulation, are reasonable and appropriate and should be approved without the changes proposed by the Attorney General, subject to further Orders of the Commission.

Issue Not Settled by the Stipulation - Final Rate Reduction

37. Based upon the foregoing findings and conclusions, Duke should be required to reduce its annual level of electric operating revenues by $286,924,000 ($233,000,000 plus the $53,924,000 impact of the Commission's decisions on the issues that were not settled by the Stipulation). To achieve this reduction, Duke is required to adjust its North Carolina retail base rates to produce annual revenues of $3,684,772,000 from its North Carolina retail operations, which will allow the Company a reasonable opportunity to earn the overall rate of return on its rate base of 8.57% which the Commission has found just and reasonable.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 1 - 4

The evidence supporting these findings and conclusions is contained in Duke's verified Application and Form E-1 Rate Case Information Report, the testimony and exhibits of the witnesses, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 5 - 8

These findings and conclusions are based on the Stipulation, Duke's verified Application and Form E-1 Rate Case Information Report, the testimony and exhibits of the witnesses for the Company and the Public Staff, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 9 - 18, 20 - 22, AND 24 - 26

These findings and conclusions are supported by the Stipulation, Duke's verified Application and Form E-1 Rate Case Information Report, the testimony and exhibits of the witnesses for the Company and the Public Staff, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 19

The evidence supporting this finding of fact and conclusion is contained in the Stipulation and in the testimony and exhibits of Duke witnesses Rogers, Shrum, and Bailey and Public Staff witness Maness.

At the request of the Commission, Duke provided legal support for the EDPR in its post-hearing filings. Duke noted that there is ample precedent supporting the Commission's authority to approve a tracking rider such as EDPR for periodically truing up the changes in the incremental balance in the Company's DSM deferral account, as proposed in the Stipulation. Citing the testimony of Public Staff witness Maness, Duke further noted that the Commission approved the existing DSM deferral account and special ratemaking treatment, consisting of amortization and recovery in rates for DSM programs, pursuant to G.S. 62-2(a)(3a), which provides:

> It is hereby declared to be the policy of the State of North Carolina: . . .
>
> (3a) To assure that resources necessary to meet future growth through the provision of adequate, reliable utility service include use of the entire spectrum of demand-side options, including but not limited to conservation, load management and efficiency programs, as additional sources of energy supply and/or energy demand reductions. To that end, to require energy planning and fixing of rates in a manner to result in the least cost mix of generation and demand-reduction measures which is achievable, <u>including consideration of appropriate rewards to utilities for efficiency and conservation which decrease utility bills</u>. (Emphasis added.)

Duke stated that, given that G.S. 62-2(a)(3a) authorizes the Commission to establish a special ratemaking mechanism implemented through a deferral account, it also provides the Commission with authority to establish a rider as a special ratemaking mechanism. Both mechanisms constitute "rewards" of the type permitted by the statute.

Duke further noted that the Commission has utilized this power on a number of occasions to establish tracking elements in electric utility rates. For example, in Docket No. E-13, Sub 142, <u>In re Nantahala Power and Light Company</u>, Nantahala, which was already tracking its purchased power costs through a monthly "purchased power adjustment clause," sought authority to change to an annually adjustable "provisional" purchased power cost increment, which would be trued up after the year end, with any shortfall or overcollection incorporated in the subsequent year calculations. The Attorney General argued in that case that such a tracker was beyond the Commission's authority, claiming that G.S. 62-133.2 was the only statutory authority permitting the Commission to allow the pass-through of purchased power costs. In its October 19, 1989 Order in that docket, the Commission agreed with Nantahala and the Public Staff that (a) G.S. 62-133.2 did not apply because Nantahala did not generate electricity by use of fossil or nuclear fuels, as that statute requires, and (b) the Commission has general authority under G.S. 62-130 to approve the continued use of the purchased power cost adjustment mechanism. Quoting from its earlier Order in Docket No. E-13, Sub 44, in which it had reauthorized the old monthly adjustment clause, the Commission stated:

> North Carolina G.S. 62-130(d) states that: 'The Commission shall from time-to-time as often as circumstances may require, change or revise, or cause to be changed or revised any rates fixed by the Commission, or allowed to be charged by any public utility.' Pursuant to the authority of this statutory provision, the Commission is of the opinion that it is appropriate for Nantahala to continue to adjust its rates through changes in the power adjustment clause. In State of North Carolina ex rel. Utilities Commission v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976), the North Carolina Supreme Court authorized the use of a Commission-approved fuel adjustment clause pursuant to G.S. 62-130. The Court noted that instead of approving fixed monetary rates for electric service, the Commission may approve rates expressed as a formula which will vary with changes in different elements that make up the formula. . . . Based on our interpretation of G.S. 62-130(d) and relevant case law, we conclude that the Commission possesses the necessary authority to approve an annual purchased power adjustment procedure for Nantahala, including an annual true-up of reasonable and prudently incurred purchased power costs.

See also: Utilities Commission v. CF Industries, Inc., 299 N.C. 504, 263 S.E. 2d 559 (1980) (Supreme Court of North Carolina upheld a "curtailment tracking rate" to permit gas utilities to recover the effects of lost revenue resulting from unforeseeable curtailments of supply by gas pipelines); Utilities Commission v. Edmisten, 294 N.C. 598, 242 S.E. 2d 862 (1978) (Supreme Court of North Carolina upheld the Commission's approval of a tracking mechanism for the recovery of natural gas utilities' costs of participation in natural gas exploration programs); Utilities Commission v. Nantahala Power and Light Company, 326 N.C. 190, 388 S.E. 2d 119 (1990) (Supreme Court of North Carolina upheld the Commission's imposition of a rate decrement to pass through to customers the benefits of the 1986 income tax reduction).

Lastly, Duke noted that, given the Commission's authority under G.S. 62-2(a)(3a) and the special circumstances arising from the interim period between when the rates approved in this proceeding become effective and when the Commission issues a decision in the Company's pending Energy Efficiency Docket, Docket No. E-7, Sub 831, it is reasonable and appropriate to approve the EDPR in order to provide for timely recovery of deferred costs as a transition to a recovery mechanism approved under the new G.S. 62-133.8 once the Commission issues an Order in Docket No. E-7, Sub 831 or Docket No. E-100, Sub 113.

The Commission concludes that, as a general proposition, North Carolina law authorizes the Commission to approve a provisional formula rate, with an accompanying true-up mechanism, in situations involving cost items which are uncertain and subject to fluctuation from period to period. The costs associated with the programs subject to the proposed EDPR are uncertain in amount and subject to unpredictable fluctuations so that they can be the subject of a valid provisional or formula rate. In addition, as Duke has pointed out, the proposed EDPR can serve as a "reward" of the type explicitly authorized by G.S. 62-2(a)(3a). All parties to this docket supported approval of the EDPR. The Commission adopted a deferral mechanism for DSM costs in the context of Duke's last general rate case, and a similar deferral mechanism is proposed to be adopted in this proceeding for continuing to track differences in the costs and revenues associated with Duke's existing DSM and EE programs. The EDPR provides a mechanism for recovering or refunding the costs accrued in the deferral account on an annual basis rather than carrying these costs until Duke's next rate case. Thus, approval of the EDPR is appropriate as a legally-permissible formula rate of the type allowed pursuant to the Commission's authority under the general ratemaking provisions of Chapter 62 of the General Statutes and as a "reward" under G.S. 62-2(a)(3a), subject to modification or elimination in either Docket No. E-7, Sub 831 or Docket No. E-100, Sub 113.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 23

Between August 14, 2007, and September 20, 2007, public hearings were held in Winston-Salem, Charlotte, Durham, Marion, and Franklin for the purpose of receiving public testimony.

Four customers testified at the public hearing held in Winston-Salem. Witness Kristie Reid, a residential customer, testified in opposition to the rate increase. Witness Robin Rhyne, a residential customer and the Economic Developer for Surry County testified that she supported the proposed rate increase if it were necessary to support the construction of more generation. Witness Larry Law testified on behalf of Lorillard Tobacco Company, a large industrial customer. Witness Law testified in support of rate parity between residential, commercial, and industrial customers but expressed concern regarding the lack of specifics provided in connection with the proposed Save-a-Watt program and the cost effectiveness of the Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Witness Sandra Thomas, a residential customer, opposed the magnitude of the proposed rate increase.

Five customers testified at the public hearing held in Charlotte. Witness Jack Copeland, Jr., opposed Duke's proposal for different rate increases for residential customers and industrial customers. Witness James Howard testified on behalf of Pharr Yarns, an industrial customer. Witness Howard commented that the rates charged industrial customers should be significantly lower than the rates charged to other customer classes and, consequently, testified in support of Duke's proposed rate design. Witness Donny Hicks, President of North Carolina Economic Developers Association, testified in support of Duke's proposed rate increase. Witness Ron Smidt, Vice President of Facility Services for Carolinas Health Care System, testified in support of Duke's proposal to address rate of return discrepancies between residential and large commercial and industrial customers. Witness John Nims testified on behalf of Parkdale Mills and stated that, although he did not endorse or oppose the rate increase, he supported Duke's proposal to address the customer class rate parity issue.

Two customers testified at the public hearing in Durham. Witness Ted Conner, Vice President for Economic Development for the Greater Durham Chamber of Commerce, testified in support of Duke's request "to become more efficient in allocating power generation and distribution costs to their customers." Witness Bill Kalkaf, President and CEO of Downtown Durham, Incorporated, testified in support of Duke's proposed rate increase.

Four customers testified at the public hearing held in Marion. Witness Dave Hart, Vice President of Economic Development for the Cleveland County Chamber of Commerce, opined that the proposed increase was necessary, but requested that the cost of service be assigned fairly among the various customer classes. Witness Tony Young, Vice President of Manufacturing for the Meridian Specialty Yarn Group, testified in support of the proposed rate increase. Witness David Johnson, whose company markets and sells residential demand control systems within Duke's service territory, testified that Duke's current and proposed time-of-use rate fails to encourage energy efficiency by providing incentives to customers to either control demand or shift usage to off-peak hours. Witness Roxanne Boyd, a residential customer, stated that she believed the customer hearing might provide "some insight on why my power bill is so high" and, consequently, that is why she attended the hearing.

Six customers testified at the public hearing held in Franklin. Witness Verlin Curtis, Alderman for the Town of Franklin, testified in opposition to the proposed rate increase. Witness Dan Roland testified on behalf of Jackson Paper and expressed support for Duke's proposed rate increase. Witness Jan Unger testified on behalf of Zickgraf Enterprises and stated that the Company was supportive of the proposed rate increase to the extent such an increase more equitably allocated utility expenses among customer classes. Witness Roy Sargent stated that Duke had "trimmed the customer service"; commented that it currently takes longer to bring service back on line after an interruption than it did in 1991; and further noted that it takes longer to report a power outage than it used to. Witness Sargent requested that the Commission investigate the deterioration in the level of customer service in the Nantahala area prior to approving Duke's requested rate increase. Witness Sargent further requested that the Commission deny any portion of Duke's requested increase that would be used for business expansion. Witness Narelle Kirkland testified in opposition to the proposed rate increase. Witness David Johnson, who previously testified at the Marion public hearing, further commented that residential customers should receive virtually no rate increase or only a very small increase and that any increase should be applied to the heavier users.

On December 14, 2007, Duke filed a letter with the Commission setting forth Duke's response to the service quality issues presented by witness Roy Sargent at the public hearing held on September 20, 2007, in Franklin, North Carolina. In its letter, Duke stated that, after the public hearing, Duke's representatives discussed with witness Sargent his concerns relating to his attempt to report a power outage in the Nantahala area in July, 2007. Duke further stated that the Company conducted an investigation and determined that the telephone directories in the Nantahala area published an incorrect number for reporting power outages, which appeared to be the root cause of the problem witness Sargent experienced. By letter dated September 26, 2007, Duke informed witness Sargent about the results of the Company's investigation. This letter was filed with the Commission on December 14, 2007. According to Duke, witness Sargent has had no further communication with the Company regarding his concerns.

Consistent with Paragraph 18 of the Stipulation and the evidence of record, the Commission finds and concludes that the overall quality of electric utility service provided by Duke to its North Carolina retail customers is good.

EVIDENCE IN SUPPORT OF FINDINGS OF FACT AND CONCLUSIONS NOS. 27 – 30

These findings and conclusions are supported by the Stipulation, Duke's verified Application and Form E-1 Rate Case Information Report, the testimony and exhibits of the witnesses for the Company and the Public Staff, the testimony of DENR witness Brock Nicholson, and the entire record in this proceeding. These findings and conclusions are not contested by any party.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 31

This finding of fact and conclusion concerns the FASB's SFAS No. 158. It is supported by the Stipulation, Duke's verified Application and Form E-1 Rate Case Information Report, the testimony and exhibits of the witnesses for the Company and the Public Staff, Duke's late-filed exhibits and comments in response to the Commission's Post-Hearing Order, the Public Staff's comments in response to the Post-Hearing Order, and the entire record in this proceeding. In this regard, the Stipulation provides as follows:

8. SFAS 158 ISSUE.

A. In Docket No. E-100, Sub 112 the Company and the Public Staff differed as to whether the treatment of deferrals by Duke Energy Corporation, the parent of Duke Energy Carolinas, in compliance with SFAS 158, required Commission approval under N.C. Gen. Stat. § 62-133.6(e) and Commission Rule R8-27, and after consideration, the Commission concluded that an evidentiary hearing was required to determine that issue.

B. The Stipulating Parties agree as follows with respect to that issue:

(1) The Stipulating Parties recommend that the Commission approve Duke Energy Corporation's establishment of a regulatory asset (using Account 182.3) with respect to Duke Energy Carolinas' apportioned share of the funded status of Duke Energy Corporation's pension and other post retirement benefit plan obligations, as part of its compliance with SFAS 158.

(2) Without conceding that approval is required by N.C. Gen. Stat. § 62-133.6(e) or Commission Rule R8-27, Duke Energy Corporation agrees, subject to Commission approval, to establish a regulatory asset (using Account 182.3) with respect to Duke Energy Carolinas' apportioned share of the funded status of Duke Energy Corporation's pension and other post-retirement benefit plan obligations, as part of its compliance with SFAS 158.

(3) Without conceding that approval is not required by N.C. Gen. Stat. § 62-133.6(e) or Commission Rule R8-27, the Public Staff agrees not to assert in this or any future proceeding that Duke Energy Corporation's establishment of this regulatory asset in

> itself affects Duke Energy Carolinas' rates or service so as to support a finding that Duke Energy Corporation is a public utility under N.C. Gen. Stat. § 62-3(23)c.

Thus, the Stipulating Parties have recommended that the Commission approve Duke Energy's establishment of a regulatory asset in Account No. 182.3 with respect to Duke's apportioned share of the funded status of pension and OPEB plan obligations as part of its compliance with SFAS No. 158. However, as discussed subsequently, the Commission has concluded that further examination, evaluation, and review of this issue are needed. Therefore, the Commission is of the opinion, and so finds and concludes, that Paragraph 8 of the Stipulation should be approved on a provisional basis pending completion of the Commission's further inquiry.

The issues which the Commission believes call for additional inquiry primarily involve pension costs and pension funding[1] from the standpoint of their impact and potential impact on rates. Specifically, the additional issues concern (1) the unsystematic manner in which Duke's pension obligations have been funded by Duke Energy and (2) the impact of these funding practices on the "regulatory asset" placed on Duke Energy's books as a result of application of SFAS No. 158.

In response to questions from the Commission, Duke witness Jacobs testified that Duke's obligations for pensions were underfunded by approximately $300 million on a total-company basis.[2] According to witness Jacobs, no contributions were made to Duke's pension fund in either 2005 or 2006, while the levels of pension costs charged to Duke's cost of service as operating revenue deductions and capitalized for those years appear to have been approximately $48.5 million[3] and $55.7 million,[4] respectively.

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[1] The Commission's concerns regarding OPEB costs and funding are more limited than its concerns regarding pension funding. That is due to the fact that OPEB obligations are funded internally and the fact that the OPEB fund balance is treated as cost-free capital in determining the Company's cost of service for ratemaking and earnings surveillance purposes; at least, the Commission understands that to be the case. However, as discussed elsewhere herein, the Commission is requesting that the Public Staff examine and evaluate certain specific issues which, in part, involve both pension and OPEB costing and funding.

[2] Witness Jacobs further testified that Duke's OPEB obligations were also underfunded, on a total-company basis, by approximately $300 million.

[3] See Duke's response to Question No. 5-4 (as identified by Duke), as set forth in its filing of November 1, 2007, in response to the Commission's Post-Hearing Order.

[4] This is an estimated amount based upon information presented in Duke's Late-Filed Exhibit No. 10, which was contained in its filing on October 26, 2007. This exhibit shows, among other things, that, for the 2006 test period, $44.5 million of pension expense was included as an operating revenue deduction on a total-company basis. In providing actual cost information for calendar years 1997 through 2005, Duke assumed that 80% of such costs were charged to expense and that 20% were capitalized. Making those same assumptions for the 2006 test period implies that total pension costs charged to expense and capitalized for that year were approximately $55.7 million. The Commission is mindful of the fact that the 2006 test-period level of pension expense may reflect a normalized level. However, any difference that may exist between the actual and normalized amounts of pension expense would not appear to be so material as to significantly alter the Commission's finding and conclusion that further examination and evaluation are needed in this regard.

Duke's North Carolina retail jurisdictional share of the $300 million in underfunded pension obligations is approximately $210 million.[1] Duke's North Carolina retail jurisdictional share of the pension costs charged to the cost of service as operating revenue deductions and capitalized in 2005 and 2006 are approximately $31.3 million[2] and $39 million,[3] respectively.

The Commission, in its Post-Hearing Order, requested that Duke provide certain additional information concerning this matter as a late-filed exhibit and that the parties brief certain additional issues. The additional issues were addressed by Duke and the Public Staff.

In its Supplemental Brief, Duke observed that its parent, Duke Energy, is responsible for funding the pension obligations of Duke and that Duke Energy's funding decisions and the timing of such decisions are based principally on (a) the funding requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA), and in the future, the Pension Protection Act,[4] when the applicable provisions of that law become effective; (b) the current expected funded status of the pension fund given those requirements; (c) the deductibility rules set forth in the Internal Revenue Code; and (d) the expected and actual returns on plan assets.

Duke noted that Duke Energy maintains separate plans for the pension benefits of legacy Duke Energy (including Duke) employees and legacy Cinergy Corp. employees and that the assets for each of its tax-qualified defined benefit retirement plans are held in a single Master Retirement Trust. According to Duke, a single trust allows Duke Energy to maximize administrative efficiencies and to achieve the lower money management fees that are available to larger pools of assets. Duke stated that Duke Energy keeps separate accounting records for each unique business unit, such as Duke.

Duke explained that plan assets are tracked in two separate steps. First, in accordance with ERISA, the assets for each of the plans, as well as the earnings on those assets, are accounted for separately and, at all times, each plan's asset balances are separately identifiable and are only available to pay benefits for participants in that plan. Second, for purposes of accounting, when pension fund contributions are made, the cost of the contributions is separately accounted for and allocated to the appropriate business unit, so that the cost of contributions with respect to Duke's employees, for example, are allocated to Duke.

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[1] The allocation of these costs to the North Carolina retail jurisdiction is based upon a factor of 69.987%, which appears to be consistent with comparable allocations made by Duke.

[2] See Duke's response to Question No. 5-4 (as identified by Duke), as set forth in its filing of November 1, 2007, in response to the Commission's Post-Hearing Order.

[3] The allocation of this estimated amount is based upon a factor of 69.987%, which appears to be consistent with comparable allocations made by Duke.

[4] According to Duke, "[t]he Pension Protection Act of 2006, another federal law that imposes funding rules for pension plans, becomes effective January 1, 2008. This law makes the most significant changes to pension funding since the passage of ERISA in 1974. Among other things, it provides for the acceleration of cash funding, increased disclosure requirements, and restrictions on benefit improvements and payment of lump sums for under-funded plans."

Duke stated that pension funding obligations are fixed by ERISA and the Pension Protection Act, whereas the rules governing accounting for pension plans are established by the FASB. Therefore, according to Duke, a plan's "funded status" as determined under the accounting rules may indicate that the plan is underfunded although the same plan, under the applicable ERISA and Pension Protection Act funding rules, is, in fact, not underfunded using the tests required by those laws. Duke averred that these two sets of rules have different purposes: "[T]he ERISA rules are intended to ensure the protection and adequacy of funds to satisfy its pension obligation, whereas the accounting rules are intended to provide adequate and consistent disclosure to investors about the status of such funding."

Duke acknowledged that, "[i]t is correct, as the Commission notes, that the greater the level of earnings on pension plan assets, the lower the net cost of pensions includable in rates." However, Duke also noted that there are other factors that impact the performance of a company's pension fund and the determination of its funded status. Duke stated that some of those factors are wholly within a company's control and others are not.

In its Post-Hearing Order, the Commission requested that the parties address the following question:

> Should the Commission require, as a minimum, that all pension and OPEB net costs included in Duke's North Carolina retail rates be accrued and funded on an annual basis at the level included in rates based upon actual, annual kWh sales, or some other actual-sales basis, if more appropriate, and that such cost recovery be accounted for accordingly?

Regarding pensions, Duke responded that the Commission should not require the Company to accrue and fund such net costs on an annual basis at the level included in rates, stating that such systematic accrual and funding may not result in the best fund performance or lower rates to customers. Duke commented that accrual and funding based upon actual, annual kWh sales, or some other actual-sales basis, are not appropriate and may be inconsistent with ERISA's minimum funding requirements and the deductibility limits set forth in the Internal Revenue Code. Duke observed that its outside actuary, Hewitt Associates, LLC, estimates pension expense each year based on the accounting rules set out in SFAS No. 87, entitled "Employer's Accounting for Pensions," and that such expense varies from year to year. Accordingly, Duke contended that pension expense should be treated like any other operating expense that varies from year to year. Duke noted that, under North Carolina law, rates are to be established in general rate cases based on a test-period level of costs and that such rates are intended to enable the utility to recover its ongoing level of total costs and to provide a reasonable return for its investors. Duke stated that it was of the opinion that the representative level of pension costs it proposed, and which was implicitly agreed to by the parties to the Stipulation, is reasonable and appropriate for inclusion in its cost of service for purposes of this proceeding.

Duke explained that, because costs included in the cost of service do vary from year to year, the Commission has established procedures for Duke to report its North Carolina retail earnings on a quarterly basis. According to Duke, this Form ES-1 surveillance reporting requirement allows the Commission to review the financial performance of Duke and the overall reasonableness of its rates as established in general rate cases such as this proceeding. Duke submitted that an important cost element in this equation is the level of pension expense as determined under the provisions of SFAS No. 87. In conclusion, Duke stated that the level of pension costs included in rates has been rationally accrued and funded by Duke Energy and that Duke's ratepayers and employees have benefited from a careful, consistent approach that weighed all of the relevant economic, legal, and accounting factors.

In responding to the foregoing question posed by the Commission, the Public Staff stated as follows:

> As indicated by witness Maness at the October 17, 2007, hearing, whether the pension and OPEB costs included in Duke's North Carolina retail rates should be accrued and funded annually at the level included in rates on an actual-sales basis is a complex issue that would require further review before the Public Staff could formulate a position. Moreover, while deferrals may be appropriate for certain items, the Public Staff generally views the historical test period as a model or guide for determining a revenue requirement that will allow a utility the opportunity to recover its overall cost of service rather than as a basis for tracking specific categories and amounts of expenses, revenues, and rate base changes over time. This is the ratemaking approach taken in the Stipulation in this proceeding.

Additionally, the Public Staff, in its response to the Post-Hearing Order, stated as follows:

> It is reasonable to assume that, if the pension plan is not systematically funded, annual net periodic pension costs will be higher and the amount of the liability for those obligations will be larger.

To gain additional insight into Duke Energy's pension funding approach, the Commission performed a preliminary quantitative analysis employing certain simplifying assumptions. This analysis compares the impact of two different funding approaches and measures their effectiveness in terms of their comparative impacts on pension fund earnings and pension fund balances at the end of calendar year 2006. The analysis, which follows, is based upon the information contained in Table A below:

TABLE A

Statement of Annual Pension Costs Expensed and Capitalized and Amounts Contributed to Trust Fund - North Carolina Retail

For Calendar Years 1997 Through 2006
(Millions of Dollars)

Line No.	Year (a)	Amounts Expensed And Capitalized ($) (b)	Amounts Contributed To Trust Fund ($) (c)
1	1997	28.0	-
2	1998	26.7	-
3	1999	26.3	-
4	2000	15.8	-
5	2001	13.3	-
6	2002	7.0	-
7	2003	19.2	85.6
8	2004	20.9	121.0
9	2005	31.3	-
10	2006	39.0	-
11	Total	227.5	206.6

The information contained in Table A was taken, in large measure, from Duke's late-filed exhibits. The data presented reflect the annual amounts of pension costs expensed and capitalized and the annual amounts contributed to the pension trust fund during the period 1997 through 2006, on a North Carolina retail basis. Table A includes estimated data for calendar year 2006 in regard to the amount of pension costs expensed and capitalized for that year. Derivation of the 2006 data has been previously discussed.

As reflected in Table A, Line 11, Column (b), Duke, on a North Carolina retail basis, during the 10-year period 1997 through 2006, charged to expense and capitalized a total of approximately $227.5 million in pension costs. As shown on Line 11, Column (c), Duke Energy contributed a total of approximately $206.6 million to Duke's pension fund during this same period. Thus, during that 10-year period, Duke charged to expense and capitalized approximately $20.9 million more than Duke Energy contributed to Duke's pension fund.[1]

In evaluating the impacts of the activities summarized in Table A, the Commission is of the opinion that it is entirely appropriate to also consider the time value of money, that is, the earnings impact that, potentially, could have been realized on pension fund assets had the

[1] In its response to the Commission's Post-Hearing Order, Duke noted that, "[a]s shown in the response to Question [No. 5-4], Duke Energy Corporation has contributed to the legacy Duke Energy Corporation pension plan an amount designated for Duke Energy Carolinas in excess of the pension cost charged to Duke Energy Carolinas." Duke noted that such excess contributions for the nine-year period, 1997 through 2005, addressed in Question No. 5-4, were $28 million. The North Carolina retail portion of that total-company amount is approximately $18 million. Duke's analysis does not take into account the pension cost charged to its cost of service and capitalized in 2006 and does not consider the time value of money, the importance of which is clearly significant. Such significance is discussed subsequently.

pension fund actually been funded on an annual basis at the same level as such costs were charged to expense and capitalized each year during the 10-year period. In performing that aspect of the analysis, the Commission utilized 7% as a proxy for the appropriate earnings rate.

Based upon the foregoing assumptions, it appears to the Commission that, if the amounts shown in column (b) of Table A had been invested annually, at the end of each calendar year, such that they would have earned a return of 7% compounded annually, the balance in the pension fund associated with that cash flow stream, on a North Carolina retail basis, would have been approximately $311.1 million at the end of 2006. If one were to make those same assumptions with regard to the actual funding levels shown in column (c) of Table A, the balance in the pension fund associated with that cash flow stream, on a North Carolina retail basis, would have been approximately $243.4 million at the end of 2006, or approximately $67.7 million less than the pension fund balance under the former approach.

Stated alternatively, based upon the assumptions noted above, had the pension fund been systematically funded on an annual basis at the same level as such costs were charged to expense and capitalized each year during the 10-year period from 1997 through 2006, as compared to the manner in which it was actually funded during those years, contributions to the pension fund would have increased by approximately $20.9 million and fund earnings would have been approximately $46.8 million higher.

The Commission is well aware of the fact, as indicated by Duke, that there are numerous factors that enter into Duke Energy's decisions regarding the funding of Duke's pension obligations. However, the Commission continues to be interested in whether the approach employed by Duke Energy for the 10-year period 1997 through 2006 produced as favorable a result for Duke's North Carolina retail ratepayers, from the standpoint of cost minimization, as, conceivably, could have been achieved under a more systematic approach. Consequently, the Commission determines that the Commission, the Company, and the Public Staff should study this issue further.

Additionally, based upon Duke's response to the Commission's Post-Hearing Order, the Commission is interested in determining whether the level and timing of pension costs actually expensed and capitalized by Duke on an annual basis are factors that enter directly into Duke Energy's decisions with respect to the funding of Duke's pension obligations. Further, the Commission would like to explore whether such factors should be considered in Duke's funding decisions, at least from the standpoint of ensuring that ratepayer interests are fully protected.

The Commission does not, in this context, question Duke's accounting or its assertion that ERISA rules and accounting rules, when considered independently, may produce different results from the standpoint of determining the funded status of pension obligations. Rather, the Commission's area of interest is whether Duke's North Carolina retail pension obligations, regardless of whether those obligations are determined under ERISA and/or accounting rules, are funded such that Duke's North Carolina retail ratepayers receive appropriate benefits to which they are entitled. Moreover, a better understanding of these issues will be relevant to the Commission's ultimate treatment of the regulatory asset that has been stipulated to, and approved on a provisional basis, in this docket.

According to Duke, the level of pension costs included in expense is determined based upon accounting rules, that is, according to SFAS No. 87. In any event, to the extent pension obligations are underfunded based on those rules, or for that matter under other rules, the potential exists for Duke to seek recovery of the unfunded amount through rates. In fact, generally speaking, that is the reason why, under accounting rules promulgated by the FASB and by this Commission, regulated enterprises are allowed to defer such costs as "Other Regulatory Assets."[1] Duke witness Jacobs' testified that, to the extent pension funding shortfalls identified under accounting rules materialize, Duke would seek recovery of those costs through rates:

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[1] SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit pension or other postretirement plan, measured as the difference between plan assets at fair value and the benefit obligation, as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which changes occur through accumulated other comprehensive income. SFAS No. 158 also requires entities to recognize as a component of accumulated other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost of the period pursuant to SFAS No. 87 and SFAS No. 106, entitled "Employers' Accounting for Postretirement Benefits Other Than Pensions."

With respect to the financial statements of an enterprise that has regulated operations that meet certain criteria, such enterprises are required to account for the effects of regulation under the provisions of the FASB's SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation." Among other things, SFAS No. 71 provides as follows:

> An enterprise shall capitalize all or part of an incurred cost [footnote omitted] that would otherwise be charged to expense if both of the following criteria are met:
>
> a. It is probable [footnote omitted] that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.
>
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

Furthermore, the Commission, as set forth in Commission Rule R8-27, has adopted, as its accounting rules for jurisdictional electric utilities the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, as currently embodied in the United States Code of Federal Regulations, Title 18, Part 101 (USOA), subject to certain exceptions and conditions. This USOA had been previously adopted for use by the Federal Energy Regulatory Commission (FERC), or more precisely, the FERC's predecessor, the Federal Power Commission.

Among other things, Rule R8-27 provides that ". . . electric utilities under the jurisdiction of the Commission must apply to the Commission for any North Carolina retail jurisdictional use of . . . Account 182.3 – Other Regulatory Assets [and] Account 254 – Other Regulatory Liabilities." The USOA defines regulatory assets and liabilities as follows:

> 30. *Regulatory Assets and Liabilities* are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains or losses that would have been included in net income determination in one period under the general requirements of the Uniform System of Accounts but for it being probable:

MR. JACOBS: I think we would try to have customers pay for their fair share of the cost of our employees.

Because of the materiality[1] and complexity of this issue, the Commission is of the opinion, and so finds and concludes, that the entire matter of pension and OPEB costing and funding from the standpoint of their impact and potential impact on rates should be further examined and evaluated, including examination and evaluation of the interrelationship, if any, that may exist between (a) the amounts of pension and OPEB costs included in the test-period cost of service; (b) the amounts of pension and OPEB costs actually charged to expense and capitalized annually; and (c) the amount of funding actually contributed to the pension trust fund on an annual basis.

In conclusion, based upon the foregoing and the entire evidence of record, the Commission finds and concludes that (a) Duke Energy's establishment of a regulatory asset in Account No. 182.3 with respect to Duke's apportioned share of the funded status of pension and OPEB plan obligations as part of its compliance with SFAS No. 158 should be approved on a provisional basis, pending completion of the Commission's further review of this matter as provided for herein, and that (b) the Public Staff should be requested to undertake a comprehensive examination and evaluation of Duke's and Duke Energy's practices with respect to the costing and funding of Duke's pension and OPEB obligations and to file a detailed report with the Commission setting forth its findings, conclusions, and recommendations. The Commission further finds and concludes that the Public Staff should be specifically requested to include the following issues in the scope of its examination and take a position with respect to such issues:

1. Is the approach historically employed by Duke Energy in funding Duke's pension obligations economically efficient and otherwise appropriate from the standpoint of ensuring that North Carolina retail ratepayer interests are fully considered and protected and, if so or if not, why, and what remedy, if any, would the Public Staff recommend that the Commission consider ordering?

2. Should the Commission, for jurisdictional accounting, ratemaking, and reporting purposes prescribe a specific methodology to be followed by Duke for purposes of determining the appropriate amounts of costs to be assigned and/or allocated to Duke's North Carolina retail operations with respect to its pension and OPEB obligations and, if not, why, and if so, why, and what methodology would the Public Staff recommend that the Commission consider adopting?

A. that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or

B. in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

[1] As previously noted, based on information contained in Duke's November 1, 2007 filing, which was made in response to the Commission's Post-Hearing Order, the total amount of the regulatory asset recorded on Duke Energy's books attributable to Duke, at December 31, 2006, was $550.7 million on a total-company basis. On a North Carolina retail basis, such amount was $385.4 million.

3. What additional measures, if any, should the Commission implement in this regard? For example, should the Commission require follow-up reports and, if so, how often and what information should the reports contain?

4. Have Duke's North Carolina retail operations been negatively impacted, or could they be so impacted prospectively, in any way, as a result of the accounting entries entered on the books of Duke Energy associated with its application of the provisions of SFAS No. 158 (for example, due to (a) the recording of a regulatory asset on the books of Duke Energy, (b) the amount of the asset so recorded, (c) the transfer/reclassification of funds from pre-funded pension and OPEB accounts to other accounts, etc.) and, if so or if not, why, and what remedy, if any, would the Public Staff recommend that the Commission consider ordering?

Should the Public Staff, as a party to and with obligations under the Stipulation, determine that it is, in some way, constrained in its ability to undertake this examination and evaluation,[1] it should so advise the Commission by means of an appropriate filing. Otherwise, the Public Staff shall undertake the requested examination and evaluation on behalf of the Commission and is hereby authorized, in its discretion and as it deems advisable and necessary, to engage an independent accounting or consulting firm to either conduct the present examination and evaluation or, in the alternative, provide consulting assistance to the Public Staff.

Finally, the Commission is of the opinion, and so finds and concludes, that the Commission Staff should meet and confer with the Public Staff and Duke for the purpose of assisting in the administrative process as well as in defining the specific scope of this examination and evaluation of Duke's pension and OPEB plan funding practices.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 32

This finding of fact and conclusion is supported by the Stipulation and the testimony and exhibits of Duke witness Horsley and Liberty witness Antonuk. The Commission finds and concludes that all matters related to Liberty's final audit report, filed on October 1, 2007, should be bifurcated from this proceeding and will be addressed by the Commission by further Order.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 33

The evidence supporting this finding of fact and conclusion is contained in the testimony and exhibits of Duke witnesses Shrum and Ruff and Public Staff witness Peedin.

Duke witness Shrum testified in support of three pro forma adjustments to test period cost of service, as shown on Shrum Exhibit 1, Page 3, Lines 1-3, that were intended to remove the effects of the Duke Energy/Cinergy Corp. merger from the Company's North Carolina retail rates. The first adjustment increased test-period revenues by $56.5 million to eliminate the effect of the revenue decrement rider in place during the test period for the purpose of sharing 42% of the estimated five-year net merger savings with North Carolina retail customers. The second

[1] The Commission infers no criticism of the Public Staff by this statement. A conflict, if any exists, would result from the Public Staff's position as a Stipulating Party and the actions being requested of it by the Commission.

adjustment increased test-period costs by $39.9 million to eliminate the actual gross savings experienced in 2006 as a result of the merger. The third adjustment decreased test-period costs by $57.3 million to eliminate from cost of service the actual costs incurred in 2006 to achieve merger savings. Company witness Ruff testified that it was necessary to present the test-period cost of service as though the merger had not taken place, because, in compliance with the Merger Order, customers have already received their full share of the five-year net merger savings through a guaranteed up-front payment.

Public Staff witness Peedin testified that the $39.9 million by which Duke adjusted its O&M expenses is the equivalent of nine months of gross Year 1 savings as calculated in the cost-benefit study filed by the Company in the Merger Docket. Witness Peedin testified that this adjustment, in effect, reduces the amount of savings to be received by the Company's ratepayers on a going-forward basis and allows the Company's shareholders to receive the benefit of those savings.

Witness Peedin further testified that the appropriateness of the adjustment depends upon the interpretation of Regulatory Condition No. 76 of the Merger Order. Witness Peedin asserted that the Company's adjustment is inconsistent with the Commission's stated intention in its discussion of this condition in the Merger Order, which provides that customers should "receive the actual achieved benefits of Duke Power's post merger operations to the maximum extent possible."

The first part of Regulatory Condition No. 76 required the rate case filing that is the subject of this proceeding. The part giving rise to the disagreement between Duke and the Public Staff is as follows:

> To the extent the $117,517,000 one-year rate decrement flowed through by Duke Power to its North Carolina retail customers is deferred, with plans or provisions for amortization over future periods pursuant to Regulatory Condition No. 25, <u>no portion of such amount, including amortization thereof, will be eligible for recovery as a component of Duke Power's North Carolina retail rates</u> set prospectively following consummation of the Merger. In particular, <u>no allowance for same will be included in the test-year cost of service</u> developed for purposes of the general rate case proceeding to be instituted pursuant to this Regulatory Condition; <u>nor will any portion of such amount be recoverable from Duke Power's North Carolina retail ratepayers</u> by means of a rate rider or otherwise. <u>Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers</u> in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. (Emphasis added.)

According to witness Peedin, the Public Staff believes that, when interpreted in conjunction with the discussion in the Merger Order, Regulatory Condition No. 76 requires that no adjustment be made in the rate case to account for either the one-year rate decrement approved in the Merger Order or for the savings Duke Energy Corporation attributed to its shareholders in that proceeding. Peedin Exhibit I, Schedule 1, reflects the reversal of the adjustment shown on Shrum Exhibit 1, Line 3.

Witness Peedin further testified that, to reflect a full year of merger savings in this case, it was necessary to annualize the $39.9 million amount of merger savings. The annualized amount of merger savings is shown on Peedin Exhibit I, Schedule 2, Line 1. The Public Staff then reduced this total annualized amount of $53.2 million by fuel savings of $6.9 million.[1] The effect of witness Peedin's adjustments was to reduce the Company's test-year O&M expenses by a total of $46.2 million and its revenue requirement by a total of $47.8 million.

On cross-examination, Public Staff witness Peedin was asked to accept some numbers on an exhibit identified as Duke Peedin Cross-Examination Exhibit No. 1. This document purported to show that the difference between the Company's position and the Public Staff's position is the difference between net savings of $163 million and net savings of negative $269 million. Witness Peedin, however, did not accept the numbers shown on the document and responded that the gross savings in the test year are embedded in the Company's cost of service and that it appears the Company is trying to increase expenses by $39.9 million to take back the savings that have already been flowed through to customers. In addition, when asked on cross-examination if she considered the Company's pro forma adjustment to be an attempt by the Company to take back part of the $117.5 million that it had already flowed through to customers through the one-year decrement rider, witness Peedin answered that she did.

In her rebuttal testimony, Duke witness Ruff stated that, if the Commission accepted the Public Staff's position to reverse the Company's adjustment to increase O&M expenses, it would leave the Company with all the costs to achieve and no ability to share in the merger savings, causing the Company and its shareholders to see a net loss of $269.5 million ($152 million + $117.5 million). Witness Ruff also contended that setting rates in this case to provide the full benefits of the $432 million in gross savings from the merger, plus the $117.5 million decrement, would provide the customers a windfall.

Company witness Ruff agreed that the proper treatment of the merger savings is addressed in Regulatory Condition No. 76, but she differed with the Public Staff's interpretation of that Condition. She testified that Regulatory Condition No. 76 should not be read in isolation from the other Regulatory Conditions of the Merger Order. In particular, witness Ruff pointed to Regulatory Condition No. 73, which provides a one-year decrement rider by which $117.5 million, which is 42% of the North Carolina retail portion of the projected five-year net merger savings, would be shared with the Company's North Carolina retail customers. She also pointed to Regulatory Condition No. 74, which is a "Most Favored Nation" provision that assures that North Carolina retail customers do as well as customers in other Duke Energy Corporation jurisdictions "with regard to the sharing of net merger savings." These provisions make no sense, she said, if, as the Public Staff contends, virtually all of the gross merger savings must go to customers after the Company had already shared 42% of the net merger savings with them. As stated in the Company's

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[1] Regulatory Condition No. 73 provides that "any fuel related savings associated with the Merger shall be flowed through to Duke Power's North Carolina retail customers pursuant to G.S. 62-133.2." As shown in Public Staff Ruff Cross-Examination Exhibit No. 1, the estimated North Carolina retail merger savings included $4.9 million in fuel savings.

Response No. 8-4 to the Commission's October 26, 2007 Post-Hearing Order, Duke contends that the Public Staff's proposal fails to consider the $117.5 million that has already been paid to customers in the form of a decrement rider. The annual allocation of $46.2 million of merger savings to customers would result in an additional $150.3 million of benefits to customers and, when combined with the $117.5 million already received, would mean that customers would receive a cumulative benefit of $267.8 million over 5 years. If the Public Staff's position were to be adopted, it would be impossible for the Company's shareholders to achieve their share of the net savings accepted in the Merger Order. The Public Staff position would result in customers receiving 97% of the net savings over the five-year period, while shareholders only received 3%.

Turning to Regulatory Condition No. 76 itself, witness Ruff testified that Regulatory Condition No. 76 relates to the $117.5 million that was to be shared with customers through the rider. While witness Ruff pointed out that the Company did not account for the financial effect of the rider by deferral, as Regulatory Condition No. 25 permitted, but instead recorded its effects as they occurred, the Company's test-period cost of service does not include any of the revenue-reducing effect of the rider. (In Shrum Exhibit 1, Page 3, Line 1 this effect is removed by a revenue add-back of $56.5 million, which is the portion of the rider that flowed through in the test period.) Thus, witness Ruff contended that the Company has complied with both the spirit and letter of the Condition. In addition, witness Ruff testified that the Public Staff's interpretation would not only be patently unfair, and constitute a retreat from the sharing arrangement that was basic to the Merger Order, it would also "communicate the unfortunate message that North Carolina is not receptive to business combinations by the utilities it regulates."

Witness Ruff further testified that this rate proceeding was not intended to provide a forum for either advocating an undoing of the equitable division of risks and rewards in the Merger Order or providing a windfall, at shareholders' expense, to customers. She contended that the Public Staff's reading of Regulatory Condition No. 76 "not only produces a grossly unfair result, but it is also at cross purposes with other Regulatory Conditions." According to witness Ruff, if the Commission intended customers to receive 100% of the merger savings, then Regulatory Condition No. 73, which provides a sharing of 42% with customers, and Regulatory Condition No. 74, which is the "Most Favored Nation" clause, would be superfluous. Finally, witness Ruff stated that it was inconceivable to her that the Company would be required to bear all of the costs of achieving the merger savings in addition to the other costs and risks associated with the merger without having any opportunity to share in the benefits.

On cross-examination, Duke witness Ruff conceded that the fuel savings number in Public Staff Ruff Cross-Examination Exhibit No. 3 is a part of the Year 1 annualized amount of $55 million, and that the $39.9 million pro forma adjustment made by witness Shrum to increase operating expenses included fuel savings that the Commission ordered to be flowed through the fuel adjustment mechanism. Witness Ruff also agreed that, under North Carolina ratemaking procedures, future savings (i.e., the full benefit of $432 million in gross savings shown on Public Staff Ruff Cross-Examination Exhibit No. 1 and Attachment C to the Stipulation in the Merger Docket) would not be reflected in the test year for this case.

In its Post-Hearing Brief, Duke presented in more detail the Company's position that the internal evidence in the Merger Order shows that the Company's intent was to offer, and the

Commission's intent was to approve, a "sharing" of 42% of the estimated five-year merger savings. In its Finding of Fact No. 11 the Commission stated that

> The primary quantifiable benefit of the Merger to ratepayers consists of the estimated merger savings . . . . Duke Power proposes to share 42% ($117,517,000) of the five year estimated net merger savings amount . . . assignable to its North Carolina retail customers.

The Company argued that, if, as the Public Staff proposed, customers were also to receive the additional benefit of the actual gross merger savings, that statement from the Merger Order was not true. Also, the Company argued, in its discussion of the evidence supporting its Finding of Fact No. 13, that the Commission said, in Footnote No. 31, that

> [T]he one year rate decrement in the amount of $117,517,000 ordered by the Commission is equivalent and equal to the exact dollar amount offered by the Company based upon its proposal to share 42% of the Company's five year estimated net merger savings assignable to its North Carolina retail ratepayers.

The Company also pointed to Page 73 of the Merger Order, where the Commission noted that the $117,517,000 decrement ordered by the Commission, rather than the $112,517,000 proposed by the Public Staff, was necessary to assure that North Carolina retail customers "in fact receive the full benefit of the exact 'sharing' required by the Duke Energy and Public Staff proposed Regulatory Condition No. 73, i.e., $117,517,000." Finally, the Company argued that the Commission on Pages 74-75 of the Merger Order found significance in the fact that the 42% sharing of the first five years of projected net merger savings was consistent with the level of sharing ordered in other jurisdictions and that it would not trigger the Most Favored Nation clauses in the orders entered in those jurisdictions. Additionally, in its Order Approving Fuel Charge Adjustment issued on April 27, 2006, in Docket No. E-7, Sub 805, the Commission noted that the merger decrement for the purpose of sharing merger savings began at the same time as the new fuel rider.

Duke further argued that, through the pro forma adjustments that it has made with respect to merger savings, it has complied with both the letter and spirit of Regulatory Condition No. 76. First, it has increased test-period revenues by $56.5 million to remove the revenue-reducing effect of the portion of the $117.5 million one-year decrement returned during the test period. This complies with the spirit of the first two sentences of the relevant portion of the Condition quoted above, although the Company chose not to defer the effect of the rider. Second, the Company's test-period cost of service contains no attempt to recover any shortfall of the shareholders' portion of the net merger savings, and this complies with the third sentence of the quoted language. Finally, by reducing test-period expenses to remove both the merger savings and the costs-to-achieve experienced in the test period, the Company has preserved the intent of the Merger Order as a whole, that is, that the customers receive 42% and the shareholders 58% of the projected five-year net merger savings.

The proper interpretation of Regulatory Condition No. 76 of the Merger Order underlies the disagreement between the Public Staff and the Company. The Company believes that, because the $117,517,000 one-year rate decrement was not "deferred, with plans or provisions for amortization over future periods pursuant to Regulatory Condition No. 25," the remaining provisions of Regulatory Condition No. 76 do not apply in this case. The Public Staff, on the other hand, believes that the language prohibiting an allowance for the rate decrement in cost of service and excluding any portion of the decrement or any portion of the net merger savings attributable to shareholders from recovery in base rates, when interpreted in light of language elsewhere in the Order and the Commission's intent to maximize the benefits of the merger to the Company's ratepayers, means that all of the savings reflected in the test-year cost of service should flow through to ratepayers.

The Commission agrees with the Public Staff's interpretation of the Merger Order and Regulatory Condition No. 76 and will, for that reason, disallow Duke's proposed adjustment to increase test-year operating expenses by $39,925,000 to eliminate gross merger savings which were actually experienced during the last nine months of the test year and will, instead, approve the Public Staff's proposed adjustment to test-year operating expenses to reflect an annualized level of merger savings minus fuel savings in the amount of $46,241,000. Longstanding general principles of ratemaking support rejection of the Company's proposed test-period adjustment to increase the cost of service by $39.9 million. The effect of Duke's proposal is to remove the gross merger savings which the Company actually achieved during the test period from cost of service. Such an adjustment is contrary to the traditional principles of ratemaking because rates in a general rate case should be designed to recover the utility's reasonable and prudent level of ongoing expenses. In this case, Duke's own evidence indicates that the Company actually achieved gross merger savings during the test year of $39.9 million and that the Company expects to achieve even greater levels of gross merger savings in the future. In fact, such savings will extend indefinitely beyond the five-year period of time reflected in the Company's cost benefit analysis as provided in the Merger Docket. To exclude these savings from Duke's cost of service in this case would clearly violate general principles of ratemaking established by Chapter 62 of the General Statutes. Simply stated, Duke's annual cost of service and revenue requirement should reflect, as closely as possible, the Company's actual costs of providing electric utility service to its customers, adjusted for known and certain changes in conditions occurring through the end of the hearing. Achieved test-period gross merger savings are clearly factors that affect the test-period cost of service and, as such, should be reflected in rates in this proceeding. Duke's shareholders will retain any gross savings above the first $46.2 million that occur each year until new rates are established in the Company's next general rate case. That result is fair to consumers and the Company.

Notwithstanding this conclusion, the Commission will, pursuant to G.S. 62-80, reconsider one provision of the Merger Order entered in Docket No. E-7, Sub 795 on March 24, 2006. The Commission will specifically reconsider that provision in Regulatory Condition No. 76 (as discussed in conjunction with Finding of Fact No. 37 in the Merger Order and the Evidence and Conclusions in support thereof) which provides that:

> . . . Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. . . .

Based on the evidence offered in these proceedings, the Commission has preliminarily concluded that the provisions of the Merger Order, as applied here, will not produce a fair sharing of the benefits of estimated merger savings between ratepayers and shareholders and, for that reason, Duke should be authorized to implement a 12-month uniform rate increment rider to collect $80,459,000 from its North Carolina retail customers for the benefit of its shareholders.[1] This amount represents 58% of the annualized level of gross merger savings of $46,241,000 reflected in rates in this proceeding for the next three calendar years (2008, 2009, and 2010); i.e., $46,241,000 gross merger savings per year, times 0.58, times 3 years, equals $80,459,000.

As an integral part of this general rate case proceeding, the Commission has carefully reviewed the provisions of the Merger Order, which govern how the benefits of the merger savings will be allocated between ratepayers and shareholders. The Merger Order was entered prior to consummation of the merger, when it was unclear whether, if consummated, the merger would result in any savings. As a result, the Commission's order was an effort to protect ratepayers from potential harmful consequences and fairly apportion potential prospective benefits. In resolving the merger savings issue in this docket, the Commission has the advantage of taking into consideration post-merger actual experience and, thus, is in a superior position to weigh the factors that must be addressed in fairly apportioning the benefits of the merger. The Commission's review has led the Commission to preliminarily conclude that, in retrospect, Duke's shareholders will not receive a fair allocation or share of the five-year estimated merger savings in light of the current provisions of the Merger Order and applicable Regulatory Conditions. In the absence of a ratemaking adjustment such as the 12-month uniform rate increment rider discussed above, the benefits of the estimated gross merger savings will be divided between ratepayers and shareholders as follows:

Item	Amount
Costs-to-Achieve Merger	$152.5 million
Ratepayer Benefit	256.1 million[2]
Shareholder Benefit	23.8 million
Gross Savings	$432.4 million

Based on this analysis, the Commission tentatively concludes that Duke's shareholders should be allowed a greater share of the estimated benefits resulting from the merger. For that reason, the Commission has preliminarily concluded that Duke should be allowed to implement the 12-month rate increment in the amount of $80,459,000 discussed above. If that is done, the benefits of the estimated gross merger savings will then be divided between ratepayers and shareholders as follows:

[1] Similarly, the merger savings sharing rate decrement in the amount of $117.5 million approved by the Commission in Docket No. E-7, Sub 795 was also implemented on a uniform, across-the-board basis for 12 months.

[2] The total ratepayer benefit of $256.1 million includes the $117.5 million rate decrement and the cumulative three-year total of the test-year gross savings amount of $46.2 million, which will be reflected in rates during calendar years 2008, 2009, and 2010.

Item	Amount
Costs-to-Achieve Merger	$152.5 million
Ratepayer Benefit	175.6 million[1]
Shareholder Benefit	104.3 million[2]
Gross Savings	$432.4 million

While any such apportionment requires an exercise in judgment, the Commission is of the opinion that this result fairly balances the interests of both consumers and shareholders and will result in both groups receiving a more fair and equitable allocation of the estimated merger savings than would be the case if the relevant provisions of the Merger Order were left intact and strictly applied. The Commission is convinced that the tenets of fair and reasonable regulatory policy, sound public policy, and fundamental fairness support reconsideration and suggest that Duke's shareholders, considering their support for the merger and their assumption of significant costs and risks in conjunction therewith, should receive the benefit of additional merger savings. The Commission concludes that the steps the Commission has and is taking adequately protect ratepayers from risks of the merger, fairly apportion merger benefits, and demonstrate the Commission's desire to avoid discouraging business combinations that, over the long term, lower costs that ratepayers must bear. This result will also be more consistent with the intent of the Stipulation and Agreement signed by Duke and the Public Staff in the Merger Docket than would be the case if the Commission were to strictly apply the provisions of the original Merger Order in this proceeding. Thus, the Commission has determined to reconsider the Merger Order.

As required by G.S. 62-80, parties will be given notice and opportunity to be heard in response to the Commission's stated intent to reconsider the specified provision of the Merger Order. However, the Commission does not intend to otherwise reconsider the Merger Order and will not entertain requests to do so. Initial comments on this matter on reconsideration should be filed by all parties not later than Friday, January 11, 2008, and reply comments should be filed not later than Friday, January 25, 2008. The Commission will then enter an Order on reconsideration after completing its review of those filings.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 34

The evidence supporting this finding of fact and conclusion is contained in the testimony and exhibits of Duke witnesses Shrum and Wright, Public Staff witness Maness, and the late-filed exhibits submitted by the Company at the request of the Commission. The Commission has also taken judicial notice of the record and Orders issued in Docket No. E-7, Sub 690.

Duke witness Shrum testified that the Company included in operating revenue deductions a five-year amortization of the costs it incurred in attempting to comply with Order No. 2000 and related Orders issued by the Federal Energy Regulatory Commission (FERC). These Orders

[1] The total ratepayer benefit of $175.6 million includes the $117.5 million rate decrement and the cumulative three-year total of the test-year gross savings amount of $46.2 million, which will be reflected in rates during calendar years 2008, 2009, and 2010 minus the $80.5 million surcharge which the Commission is herein proposing to collect from ratepayers for the benefit of Duke's shareholders.

[2] The total shareholder benefit of $104.3 million includes the $80.5 million surcharge, which the Commission is herein proposing to collect from ratepayers.

required the Company to file a plan to form or join a Regional Transmission Organization (RTO) or explain why that action could not be accomplished. Witness Shrum testified that, in response to the directives of the FERC, the Company, along with Progress Energy Carolinas, Inc. (PEC) [formerly known as Carolina Power and Light Company (CP&L)] and South Carolina Electric & Gas (SCE&G), formulated plans to establish GridSouth Transco LLC (GridSouth) as an RTO that would assume functional control of the three utilities' transmission systems. During the "final development stages of GridSouth," however, the FERC's policy regarding RTOs shifted dramatically, causing the three utilities (referred to collectively as the GridSouth participants) to initially suspend and ultimately abandon the project.

Witness Shrum testified that these costs relate to "building and implementation costs associated with the development of GridSouth" and that, if the Company had ultimately been required by the FERC to join an RTO, these costs would have been included in the transmission fee charged by the RTO to the Company, and thus would have been eligible for inclusion in retail cost of service. She also testified that deferral of these costs had been allowed by the FERC in an Order issued January 25, 2001, in FERC Docket No. EL01-13-000. Witness Shrum asserted that these costs are "a necessary part of utility operations and are used and useful in providing electric service," both because the Company incurred them in response to the FERC's Orders and directives with which it was required to comply and because the operation of GridSouth would have benefited both retail and wholesale customers.

A review of Duke's Form E-1 Rate Case Information Report, Item 10, Pages ND-2300 through ND-2303, and the late-filed exhibits filed by the Company at the request of the Commission, shows that the total system amount of GridSouth costs deferred on the Company's books at March 31, 2007, was $58,444,000, consisting of a principal amount of $41,254,000 and accrued carrying charges of $17,191,000. The Company estimated that an additional $3,930,000 of carrying charges would be accrued during the remainder of 2007, resulting in the total amount of $62,374,000 for which the Company requested a five-year amortization. This $62,374,000 has been allocated by the Company as follows: $43,936,000 to the North Carolina retail jurisdiction, $15,612,000 to the South Carolina retail jurisdiction, and $2,826,000 to the wholesale jurisdiction. The Company's proposed North Carolina retail amortization of $8,787,000 was determined by dividing $43,936,000 by five years. As of June 2002, the Company had incurred $41,254,000 of GridSouth costs. North Carolina's jurisdictional share at that time was $29,059,000.

Public Staff witness Maness and Company witness Wright each presented testimony describing the development of GridSouth. Most of this evidence is not in dispute and is summarized below.

The process which led to the FERC's encouragement of RTO formation had its roots in the 1970s, when non-utility owned electric generating facilities began to be developed as a result of a number of circumstances, including the passage of the Public Utility Regulatory Policies Act of 1978. In an effort to promote greater competition in wholesale power markets, Congress subsequently adopted the Energy Policy Act of 1992 (EPAct 1992). Following the enactment of EPAct 1992, the FERC embraced the idea that a more definitive open access transmission paradigm than had previously existed was required to facilitate effective wholesale competition and introduced the idea of Regional Transmission Groups in a 1993 policy statement. Subsequently, in April of 1996, the FERC adopted Order Nos. 888 and 889 for the purpose of encouraging wholesale competition by requiring the provision of open access transmission service in the wholesale bulk power marketplace.

Company witness Wright testified that, on December 20, 1999, the FERC issued Order No. 2000, which required utilities regulated by the FERC to undertake to join or form an RTO that would be operational by December 31, 2001, or to provide an explanation as to why this could not be accomplished. Witness Wright testified that the GridSouth participants submitted their compliance filing to the FERC on October 16, 2000. That filing described the proposed structure and operations of GridSouth. Pursuant to that filing, the GridSouth participants were to retain system expansion planning responsibility for the Carolinas, the native load preference would be preserved, and the North Carolina and South Carolina Commissions would retain jurisdiction over all aspects of retail electric service, including the transmission component of retail rates.

Public Staff witness Maness testified that the GridSouth participants noted in their compliance filing that, due to the fact that retail rates remained regulated and bundled in North Carolina and South Carolina, they did not plan to transfer ownership of their transmission assets to GridSouth at that time; instead, they planned only to transfer functional control. Additionally, they noted that the proposed GridSouth Transmission Operating Agreement provided that the transmission component of bundled retail service would not be subject to transmission charges under the GridSouth Open Access Transmission Tariff (OATT). In other words, none of the GridSouth participants planned to separately purchase transmission service for their retail customers pursuant to the OATT, but would, instead, continue to recover costs of transmission from these customers as part of their bundled retail rates.

On November 3, 2000, the GridSouth participants filed with the FERC a request for a Declaratory Order seeking approval of their proposed accounting treatment for GridSouth costs. The FERC addressed that request in Carolina Power and Light Co., et al., 94 FERC ¶ 61,080, on January 25, 2001. According to witness Wright, the FERC allowed the GridSouth participants to treat their ongoing investment in GridSouth as deferred debits and to accumulate carrying costs on these amounts in that Declaratory Order. Public Staff witness Maness added that, because GridSouth was not yet operational, the FERC required the GridSouth participants to record the amount that would eventually become a receivable in Account 186 – Miscellaneous Deferred Debits. The FERC stated that acceptance of the petition, as modified, did not amount to pre-approval of rate recovery. The Declaratory Order also allowed GridSouth to defer the recovery of start-up costs until it became operational.

Company witness Wright also testified that, in order to meet the FERC's deadlines, the GridSouth participants worked to make GridSouth an operating entity from the autumn of 2000 until the spring of 2002. Land was procured and a facility was constructed in Fort Mill, South Carolina. Operating systems and related hardware, some staffing, software, other system supports, and the related design and installation of these systems, were contracted for and obtained. The GridSouth participants established budgets and worked to control costs in several ways. For example, Requests for Proposals were issued for a variety of the systems necessary to support GridSouth. Also, a management committee comprised of one executive from each participating company oversaw major financial decisions, reviewed project team recommendations, and in general worked to control project costs.

Public Staff witness Maness noted that, on March 14, 2001, the FERC issued an Order provisionally granting RTO status to GridSouth, finding that the proposal, as modified by the FERC in the Order, would create an RTO that would be in compliance with Order No. 2000. The FERC found GridSouth to be a "good first step," but strongly encouraged GridSouth to expand its footprint within the Southeast. In a May 30, 2001 Order clarifying certain points made in the March 14, 2001 Order, the FERC explicitly confirmed that the GridSouth participants would be required to pay GridSouth for retail transmission service, even if such payments were equal to the transmission component of their bundled retail rates.

On April 2, 2001, Duke and CP&L filed a Joint Application with the Commission in Docket Nos. E-7, Sub 690 and E-2, Sub 781 seeking authorization to transfer functional control of their transmission assets to GridSouth.

Company witness Wright testified that the FERC issued two relevant Orders on July 12, 2001. In an Order issued in the GridSouth docket, the FERC expressed concern about the independence of GridSouth from the GridSouth participants. The FERC also announced that it considered it necessary for a single Southeast RTO to be established. As a result, the FERC reversed several approvals it had granted in its March 14, 2001, Order. In the second Order, the FERC initiated a mediation proceeding intended to result in the formation of one RTO for the entire Southeast.

Public Staff witness Maness noted that, in August 2001, the Commission filed a request for rehearing and a motion for a partial stay in the FERC GridSouth and mediation dockets, arguing that the functions that the FERC had ordered to be turned over to GridSouth were integral components of retail service and that any such transfer interfered with legitimate State regulation and was, therefore, unlawful. Company witness Wright added that the Commission stated that the FERC was "asserting jurisdiction far beyond its statutory authority" and that the FERC "erred by concluding that a single RTO for the Southeast is in the public interest." In its motion to join in the appeal of the FERC's March 14, 2001, Order granting provisional RTO status to GridSouth, the Commission stated that the FERC's Orders in the GridSouth proceeding infringed upon the Commission's retail ratemaking and transmission planning authority, and thus exceeded the FERC's jurisdiction under the Federal Power Act.

On August 17, 2001, the Commission issued an Order in Docket No. E-7, Sub 690 holding Duke's and CP&L's GridSouth Joint Application in abeyance. In doing so, the Commission stated as follows:

> On July 12, 2001, the Federal Energy Regulatory Commission (FERC) issued a series of orders concerning regional transmission organizations (RTOs), including GridSouth. In its orders in Docket Nos. RT01-100 and RT01-74, the FERC concluded that it is necessary that the Southeastern transmission owners combine to form one RTO and initiated mediation for the purpose of facilitating

> the formation of a single RTO for the region. The FERC directed an administrative law judge to convene a meeting of the parties, to mediate settlement discussions for a period of forty-five days, and to file a report within ten days thereafter 'which will include an outline of the proposal to create a single Southeastern RTO, milestones for the completion of intermediate steps, and a deadline for submitting a joint proposal.'
>
> In light of the FERC's recent action and the uncertainty surrounding the structure and design of the RTO, if any, to be ultimately proposed by CP&L and Duke, the Commission is reluctant to proceed at this time to consider the merits of the Application. Therefore, after careful consideration, the Commission, on its own motion, finds good cause to hold this proceeding in abeyance pending further order.

Company witness Wright also testified that, in the fall of 2001, just weeks before GridSouth was scheduled to begin operations, with so much uncertainty and with the existence of opposing views regarding the formation, structure, and governance of GridSouth and other RTOs, the project was essentially put in standby mode – meaning that employee hiring ceased and certain systems were canceled or deferred. Given the changes in the FERC's RTO policy, along with the impending issuance of a Standard Market Design Notice of Proposed Rulemaking, witness Wright testified that the GridSouth participants were prudent in reevaluating the wisdom of proceeding with their initial RTO plans.

On February 22, 2002, Duke and CP&L filed a notice of withdrawal of their GridSouth Joint Application to the Commission, which was allowed by Order dated February 25, 2002. In that Order, the Commission also closed all related dockets. These dockets were never reopened.

Company witness Wright testified that the FERC released its Standard Market Design White Paper shortly after it instituted the mediation process intended to result in the formation of four large regional RTOs. In June 2002, the three GridSouth participants terminated the project.

Public Staff witness Maness testified that on June 25, 2002, the GridSouth participants filed a letter with the FERC stating that they were postponing the filing of revised state applications because of two new developments: the preparation of an RTO cost-benefit study for the Southeastern state commissions and the initiation by the FERC of the Standard Market Design rulemaking.

Witness Maness noted that on October 15, 2003, the GridSouth participants filed a letter with the FERC stating that the GridSouth participants had terminated all GridSouth "operational aspects" so as to "cease incurring costs" as of June, 2002. On December 22, 2004, the FERC issued an Order terminating the mediation proceedings aimed at producing a single Southeastern RTO, noting that the mediation attempt had been "unsuccessful." Finally, on October 20, 2005, the FERC issued an Order terminating its GridSouth proceeding at the request of the GridSouth participants.

Witness Maness testified that, in light of all of these events, he did not agree with Duke's inclusion of an amortization of GridSouth costs in the North Carolina retail cost of service. He recommended that the Commission reject the Company's proposed amortization expense of $8,787,000. The effect of witness Maness' adjustment was to reduce the Company's revenue requirement by $9,091,000, as shown on Maness Exhibit I, Schedule 2.

Witness Maness stated that he did not believe that any part of the GridSouth costs that the Company had accrued on its books should be recovered from the North Carolina retail ratepayers, and he offered several reasons in support of his position. Witness Maness stated that it was unclear to him why it was justifiable for the Company to have maintained the North Carolina retail portion of the GridSouth deferred costs as an asset on its books through the end of 2006 without Commission approval and that there was clearly no justification for accruing a return on the costs. He testified that, when the FERC first approved the use of Account 186 for GridSouth start-up costs (in the January 2001 Accounting Order), such approval was granted in an environment where GridSouth was expected to be operational by the end of that year, which would have enabled Duke to recover the costs from GridSouth, not from its retail customers.

Witness Maness testified that, by June 2002, it was clear that the GridSouth initiative was in trouble, and he noted that, by October 15, 2003, the GridSouth participants had terminated all vendor and services contracts, released all GridSouth employees, and sold the building that would have housed GridSouth's headquarters. Thus, witness Maness concluded that, perhaps as early as mid-2002, and certainly by October 2005 (when the FERC terminated the GridSouth proceeding), the Company should have known that the premise for maintaining the costs in Account 186 (that GridSouth was a viable business venture) could no longer be sustained. Witness Maness maintained that, at that point, when there was no longer any argument for keeping the GridSouth costs recorded as an asset except for the hope that they might someday be recovered from some group of customers, the North Carolina retail portion of the costs should either have been written off as a loss or submitted to the Commission for approval of deferral as a regulatory asset. Since the Company had never requested deferral of the costs prior to this rate case, witness Maness opined that it was questionable whether the North Carolina retail portion of the costs should even have been on the books at the end of the test year. On cross-examination, witness Maness also observed that, once it became clear that GridSouth was not going to become operational, the FERC Accounting Order would have lost whatever authority it had for North Carolina retail purposes.

During cross-examination, witness Maness pointed out that Commission Rule R8-27 requires the electric utilities regulated by the Commission to apply to the Commission for approval of any use for North Carolina retail purposes of the specific account numbers set forth in the FERC Uniform System of Accounts for recording regulatory assets and liabilities. Witness Maness testified that, even though Rule R8-27 was amended to include that requirement in September 2001, the amendment occurred before the termination of the GridSouth project, the point in time that the Public Staff believes the costs should have first been considered to be a regulatory asset. Witness Maness observed that the FERC Accounting Order did not address whether the GridSouth costs were a regulatory asset, but instead approved their deferral as something akin to a receivable.

Further, witness Maness testified that, notwithstanding Duke's failure to request approval for regulatory deferral of the North Carolina retail portion of the GridSouth costs prior to this current proceeding, it nevertheless should have begun amortizing the balance it had deferred as soon as it was clear that the amount was in substance a regulatory asset. Witness Maness explained that this has been the practice of the Commission with regard to regulatory assets, such as deferred costs of major storms, and there is no reason to think that this policy should not have been applied in this instance. Because this amortization should have begun arguably as early as mid-2002, and certainly no later than the autumn of 2005, all or at least a significant portion of the costs deferred by the Company should already have been amortized by the time the rates approved in this case go into effect, if one accepts a five-year amortization period. Witness Maness also stated that, upon review of Company witness Wright's testimony that the GridSouth participants had "terminated" the project in June 2002, he felt much more confident in stating that the amortization of the regulatory asset, if one should ever have been approved, should have begun in June 2002, when the costs changed from a "quasi-receivable" to a regulatory asset.

In response to questions from the Commission, witness Maness agreed that the length of the amortization period is decided "on a case-by-case basis." Further, "for the types of expenses that I think are comparable to GridSouth, such as a major storm where you have a unique event that the Commission has some discretion in determining what the appropriate amortization period is and when it should begin, for those types of costs ever since about 1989 with Hurricane Hugo the Commission has consistently had that amortization begin the date that the event took place or in the same month or the same quarter." Witness Maness testified that amortizations have ranged in length "all the way from approximately three years to five and maybe in some cases ten." And, upon further cross-examination, witness Maness agreed that some amortizations related to plant abandonments in the 1980s were done over 10 years.

In addition, witness Maness testified that it was his opinion that the inclusion in rates of any of the costs deferred by Duke would be unreasonable for the simple reason that it would impose higher transmission-related costs on the Company's North Carolina retail customers than likely would have been imposed on those customers if GridSouth had become an operational RTO. As noted previously, if GridSouth had gone forward, the costs deferred on the Company's books would have eventually been paid for by GridSouth and become part of GridSouth's costs. As such, they would have been recovered through the rates that GridSouth would have charged customers for purchasing transmission service. In any GridSouth proceeding before the Commission, witness Maness opined that the Public Staff would likely have recommended that the North Carolina retail ratepayers be held harmless from any adverse effects on either the Company's service or its rates resulting from its membership in GridSouth. Moreover, witness Maness commented that the Public Staff could see no reason why the Commission would not have excluded from the Company's rates all direct and indirect costs associated with the formation and operation of GridSouth in much the same manner as it excluded similar costs when it allowed Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (DNCP), to integrate with PJM Interconnection, LLC (PJM). In requesting amortization of GridSouth deferred costs, however, witness Maness asserted that the Company was proposing to do what it most likely could not have done had GridSouth become operational – namely, require the North Carolina retail customers to pay both the traditional embedded costs of bundled transmission service and some of GridSouth's costs.

Witness Maness elaborated that if the Company had come to the Commission for approval to transfer functional control of its transmission assets to GridSouth, the Public Staff would have taken a "strong position" that in order to hold the ratepayers harmless from that transfer, any additional GridSouth costs over and above the Company's own transmission costs would need to be offset by benefits from GridSouth operation before the costs could be allowed to be included in North Carolina retail rates. Since GridSouth never became operational, witness Maness asserted that there is now no chance for the North Carolina retail ratepayers to experience any of those benefits; therefore, if the costs were now to be passed on to North Carolina retail customers, they would not in fact be held harmless from the effect of GridSouth.

With regard to the DNCP-PJM Order, witness Maness was cross-examined regarding the fact that, in that proceeding (Docket No. E-22, Sub 418), DNCP explicitly offered to forego recovery of increases in costs due to certain PJM charges. Witness Maness acknowledged that such was the case, but pointed out that the Commission indicated in its Order that DNCP's offer was not sufficient to protect ratepayers, primarily because it was for a limited period of time, and the Commission ordered that the exclusion of those costs would continue indefinitely until further Commission Order.

In response to questions from the Commission, witness Maness acknowledged that the Public Staff had not investigated whether the GridSouth costs that the Company was proposing to amortize were incurred prudently because the GridSouth matter never proceeded to hearing or the filing of comments related to the relevant substantive issues. However, witness Maness stated that the reasonableness and prudence of the costs was irrelevant to the Public Staff's position in this case because, whether the costs were prudent or imprudent, the ratepayers should be held harmless from adverse effects on their rates or service.

Duke witness Wright testified that, from his perspective, the decision by the Company to pursue a North Carolina and South Carolina based RTO was proper, based on the then-current circumstances, in that the successful implementation of this plan would have left the control and oversight of this RTO, to the extent possible, within this region and preserved the jurisdiction of the Commission and the South Carolina Commission over retail transmission service. Witness Wright further testified that the FERC's approach to RTO formation was to "strongly" encourage transmission owners to participate "voluntarily" while remaining "neutral" as to organizational form of an RTO, provided that it satisfied the FERC's "minimum characteristics and functions. . . ." Witness Wright asserted that, at the time of Order No. 2000, the FERC was clearly committed to the formation of RTOs, although the FERC's approach at that time allowed for variations in the structure and functions of RTOs in order to accommodate local concerns and interests. Witness Wright maintained that this strong "encouragement" by the FERC came to be correctly interpreted by the industry as a mandate.

Witness Wright observed that, in order to strongly "encourage" RTOs, the FERC had clearly signaled that utilities not joining an RTO would be subject to substantial risks, including the possible loss of their ability to sell power at market-based rates in wholesale markets. Witness Wright contended that there was simply no question that the Company had to begin planning the development of an RTO or begin discussions related to joining an existing RTO. At the time of the issuance of FERC Order No. 2000 on December 20, 1999, according to witness

Wright, each of the GridSouth participants was faced with one of three unenviable choices: (1) developing a North and South Carolina based RTO within 10 months; (2) convincingly demonstrating to the FERC why they could not form an RTO while other utilities were doing just that; or (3) facing the probability of being subject to the jurisdiction and rules of other RTOs that were beginning to be developed in other southeastern states.

During cross-examination, witness Wright agreed that, in the rulemaking proceeding that led up to the adoption of Order No. 2000, Duke had argued to the FERC that until state commission review of restructuring and RTOs was completed, it would be premature for a utility to commit to an RTO membership. While witness Wright agreed that it was a permissible option for a utility to make a filing stating that it had not had time to do a cost benefit study or that the State in which it operated had not pursued restructuring, he asserted that such a filing would not have been practical. Witness Wright remarked that he did not know of any utilities in the Southeast that had done so. On the contrary, witness Wright stated that, since every other Southeastern investor-owned utility had responded to the FERC's Order 2000 by undertaking the development of an RTO, it would have been untenable for the Company and other North Carolina and South Carolina utilities to argue to the FERC that they could not form or join an RTO.

According to witness Wright, based on FERC Order No. 2000, the Company and its GridSouth participants felt that an RTO covering the North Carolina and South Carolina region would best suit customers and regulators in that it would be: focused in its scope; more attuned to the customer and system needs of the Carolinas; and more cost effective than other alternatives. Witness Wright opined that the GridSouth participants also believed that their mutual cooperation and similar state regulatory oversight would provide a smooth transition to an RTO environment since the three companies had a long and positive history of operating their systems cooperatively. Witness Wright observed that GridSouth represented a unique opportunity to create a locally-based RTO answerable to the customers of North Carolina and South Carolina, which the Company believed was preferable to both it and this Commission than the alternatives. At the time the decision to enter the project was made, it was witness Wright's opinion that all indications were that GridSouth complied with the FERC's RTO requirements.

Witness Wright asserted that it was prudent and reasonable for the Company to continue with the GridSouth development in the 2000/mid-2002 time frame. He stated that, in the January 25, 2001 Declaratory Order, the FERC granted the GridSouth participants' request to treat their ongoing investment in GridSouth as a deferred debit and to accumulate carrying costs on the underlying amounts. Witness Wright testified that the FERC Declaratory Order signaled to the GridSouth companies early on that their proposed response to Order No. 2000 was an acceptable one and that, in doing so, signaled the GridSouth companies that they should continue development of the RTO. Witness Wright also observed that the FERC response to the GridSouth application in its March 14, 2001 order generally accepted the application as being compliant with its initial RTO directives. Furthermore, the FERC encouraged the GridSouth participants to meet with Santee Cooper and other Southeastern utilities in an effort to expand the geographic scope of GridSouth. Witness Wright commented that the GridSouth participants complied with this directive and were pursuing these issues when the chairmanship of the FERC changed and the FERC's overall approach to RTOs was altered.

According to witness Wright, this change in the leadership at FERC dramatically altered the FERC's approach to RTO issues. Essentially, as explained by witness Wright, the FERC abandoned its collaborative effort at creating regional RTOs and became rather dictatorial in its approach to RTO formation. Witness Wright noted that this change, along with other changes, essentially led to both Congressional and state pressure against the FERC's proposed new RTO policies. During this time period, the formation of GridSouth was no longer viewed as consistent with the Company's, the State's, or the Nation's transmission requirements.

Witness Wright maintained that it was prudent for the Company to initially suspend and then terminate the GridSouth project. After the two FERC Orders in July 2001, "[t]here was simply no question that the FERC's RTO policy had dramatically changed, and that this change was not supported by either the GridSouth partners or the utility commissions in either North Carolina or South Carolina." Witness Wright further testified that Duke's participation in GridSouth was a required response to the FERC Orders, and that the GridSouth development costs should be deemed legitimate and proper expenses allowable for recovery. Witness Wright further contended that regulated utilities must respond to, and remain in compliance with, the directives of regulators that have jurisdiction over them, and that costs incurred to do so are a necessary part of utility operations. Also, Witness Wright stated that, if Duke had not developed GridSouth, the FERC would have taken steps to limit the Company's participation in the wholesale power market, and that the Company's North Carolina customers have received over $75 million in benefits under the Bulk Power Marketing (BPM) Sharing Arrangement.

Witness Wright argued that, because these and other costs were incurred to meet directives of a federal regulator, they are a necessary element in the overall costs related to the provision of electric service to the North Carolina retail customers; they were prudently incurred; and they should be recoverable from ratepayers. However, on cross-examination, witness Wright acknowledged that the Commission has the authority to disallow the unrecovered GridSouth development costs at this time.

Witness Wright observed that witness Maness was correct in stating that Duke would have recovered the GridSouth startup costs from GridSouth had GridSouth become operational. However, witness Wright argued that witness Maness failed to state the source from which GridSouth would have received the money to pay Duke. If GridSouth had become operational, according to witness Wright, it would have begun to reimburse the utilities that provided the start-up funding. Witness Wright pointed out that GridSouth would have required a revenue stream to begin paying that obligation. As noted in the October 16, 2000 GridSouth compliance filing, witness Wright explained that GridSouth would be collecting rates for its services, including start-up costs, from all transmission users through the Transmission Service Charge (TSC), including the retail customers of the GridSouth participants. According to witness Wright, the Company would have incurred costs in paying GridSouth its TSC and would have, in turn, included those costs as a cost of service for retail customers. Witness Wright indicated that the intent was to ultimately recover these costs from retail customers.

Witness Wright disagreed with the Public Staff's assertion that the Company should have filed with this Commission several years ago for approval of these development costs as a regulatory asset. Witness Wright testified that the GridSouth partners had already made a filing with the FERC, which has jurisdiction over RTOs, with respect to these development costs. In the Declaratory Order, the FERC agreed to defer the recovery of start-up costs until the RTO was operational, and made it plain that such costs would be recoverable from customers. However, witness Wright acknowledged on cross-examination that the Declaratory Order made it clear that GridSouth would have to submit a separate Section 205 filing to recover the initial costs, and that even the Company and the other petitioners had asserted that the allocation of the costs between retail and wholesale jurisdictions was beyond the scope of their petition in that proceeding. Witness Wright opined that the FERC was the proper forum in which to address the accounting treatment for these costs, because it was "controlling the cost and controlling the process."

In addition, witness Wright disagreed with the Public Staff's assertion that the Company should have begun amortizing these costs no later than 2005. Witness Wright argued that amortization should begin at the point the Company begins to recover these costs from customers and that this proceeding is the first opportunity the Company has had in which to seek such recovery from North Carolina retail customers.

Further, witness Wright disagreed with the Public Staff's position that retail customers should be held harmless from any adverse affects of GridSouth and that allowing recovery of these development costs would violate this principle. He stated that witness Maness's argument assumes that, had GridSouth become operational, there would be no benefits or savings resulting from the GridSouth operations, a belief that the FERC would take issue with. However, he conceded on cross-examination, that the cost benefit study prepared for the Southeastern Association of Regulatory Utility Commissioners (SEARUC) demonstrated that GridSouth was not cost-effective under any of the scenarios studied. Witness Wright also explained that witness Maness also assumes that, had the FERC allowed recovery of these development costs from all transmission users, somehow this Commission could have ignored these FERC-mandated costs. Witness Wright asserted that such a position is contrary to established precedent and constitutes bad public policy. In response to questions from the Commission, witness Wright stated that he was making essentially a policy and equity argument, rather than a legal one.

Witness Wright testified that other states had allowed recovery of RTO development costs. Witness Wright testified that South Carolina allowed recovery of GridSouth costs for SCE&G, in Docket No. 2004-178-E, Order No. 2005-2, January 6, 2005, and that other states have allowed recovery of RTO startup costs as well, including Florida (Progress Energy Florida) and Mississippi (Entergy).

In its Brief, Duke argued that the Commission's Order in the DNCP-PJM Docket is not indicative of what the Commission might have done relative to GridSouth. In particular, Duke stated that

> [U]nlike PJM, the GridSouth participants specifically designed GridSouth to be a locally based RTO answerable to the customers of North Carolina and South Carolina. The Company believed such a RTO structure was preferable to this Commission than the alternatives. (T. Vol. 4, p.139) Second, Dominion had already agreed as a part of a settlement in its rate case to charge all PJM start-up costs to non-utility operations. <u>In the Matter of Dominion North Carolina Power – Investigation of Existing Rates and Charges</u>, Docket No. E-22, Sub 412

(March 8, 2005) at p 8. Third, Dominion North Carolina Power specifically offered to exclude various PJM costs from its North Carolina retail rates (Dominion PJM Order at p. 12) and could do so without significant financial impact due to the small percentage of its North Carolina retail jurisdiction to its total system (T. Vol. 4, pp. 114-15). Accordingly, this Commission expressly stated that:

> Finally, the Commission finds that the facts and circumstances in this matter are unique, that this case is a very close one, that any application of this nature must be independently reviewed and evaluated with respect to the specific evidence presented in that case, and that this decision shall not serve as a precedent with respect to any future request by a utility to join an RTO or otherwise transfer operational control over its transmission facilities.

Dominion PJM Order at p. 27.

Duke argued that there is no basis in law or policy for the Public Staff's position that the Commission should disallow recovery for costs prudently incurred in response to a federal regulatory mandate simply because the Public Staff disputes the merits of the federal policy.

Duke argued that "this rate case is the first opportunity the Company has had to" seek approval for the recovery of the costs in rates. "When it became clear in the middle of 2002 that GridSouth would not come into being, the Clean Smokestacks Act... imposed a rate freeze through December 31, 2007." Duke argued that none of the permitted exceptions to the freeze would have covered the GridSouth development costs because, although they resulted from government action, neither the costs nor the government action occurred during the rate freeze period as the statute required. Duke argued that "it was necessary for the Company to wait until the freeze was over to seek recovery in retail rates."

In its Proposed Order, the Public Staff asserted that Duke should not have incurred significant start-up costs before the FERC issued an Order with respect to whether or not GridSouth, as proposed, was acceptable. The Public Staff argued that the FERC's provisional approval of GridSouth in its March 14, 2001 Order was on terms that were unacceptable to the GridSouth participants and to the Commission. When FERC refused to clarify the March 14 Order and instead imposed additional objectionable requirements, it should have been clear to the GridSouth participants that no further expenditure of funds was appropriate. The Public Staff pointed out that the Commission's concerns with those requirements were expressed in its August 2001 Request for Rehearing and Motion for Stay in the FERC GridSouth proceeding and its subsequent motion to join the appeal of the FERC's GridSouth Orders to the United States Court of Appeals for the Fourth Circuit.

In its Proposed Order, the Public Staff commented that, with respect to Duke's late-filed exhibit response 9-1, it is inappropriate for only 4.5%, or $2.8 million out of the $62.4 million total, to be borne by the wholesale jurisdiction - the jurisdiction that gave rise to the costs in the first place. The Public Staff observed that, during the period of the BPM Sharing Arrangement, Duke's shareholders received over $75 million in benefits. Similarly, the Attorney General argued in its Brief that, "if FERC allows Duke to recover its GridSouth costs in its wholesale transmission rates, then those costs will reduce the net transmission revenues received by North Carolina's retail ratepayers. . . . Any additional GridSouth costs recovered from North Carolina retail ratepayers should be recovered from the Industrial Class."

In its Brief, the Attorney General contended that "Duke's reliance on a FERC Order allowing deferral of GridSouth start-up costs until the RTO became operational is misplaced." In addition, the Attorney General observed that "Duke failed to request that the Commission defer Duke's GridSouth costs for later recovery, even though Duke had the opportunity to do so in the GridSouth docket that was opened by the Commission at Duke's request in April 2001."

Further, the Attorney General argued that, even if Duke had requested deferral of the GridSouth costs and the Commission had found deferral to be in the public interest, the Commission likely would have ordered, at most, a five-year deferral schedule, beginning no later than the month in which Duke knew that GridSouth was no longer feasible and thus ceased incurring costs, which was in June 2002. The Attorney General noted in his Brief that "as a general rule the Commission has not favored cost deferrals, allowing deferral only when expenses are unusual and would have a material effect on a company's financial position."

In addition, the Attorney General maintained that under the Clean Smokestacks Act, cost deferrals were prohibited during the rate freeze period - June 20, 2002 through December 31, 2007 - unless the Commission found such deferrals to be in the public interest. (G.S. 62-133.6(e). The Attorney General remarked that the purpose of this section was to prevent a utility from eroding the benefits of the rate freeze by deferring costs and including them in rates set after the rate freeze. The Attorney General asserted that Duke's request to defer GridSouth costs and include them in rates beginning in 2008 would defeat that purpose. The Attorney General concluded that, "Duke having failed to give the Commission the opportunity to determine whether the public interest would have been served by deferring the GridSouth costs during 2002 through 2007, its present request to include those costs in retail rates should be denied."

Both the Public Staff and the Attorney General argued that the Company should have been aware that the deferral of GridSouth development costs for North Carolina retail regulatory purposes would require an application to the Commission pursuant to the Clean Smokestacks Act.

The Commission believes that a proper resolution of the GridSouth issue requires a two-step analysis. First, the Commission must determine whether any deferral of GridSouth-related costs for subsequent amortization is lawful under the Clean Smokestacks Act. Second, the Commission must determine whether allowing deferral and subsequent amortization in rates of GridSouth-related costs is consistent with considerations of sound regulatory policy and, if so, how any allowed deferral and amortization of GridSouth-related costs should be structured. The Commission will address each of these issues in turn.

The North Carolina General Assembly enacted the Clean Smokestacks Act in 2002. By its explicit terms, the statute precludes changes in base rates and certain cost or revenue deferrals during a rate freeze period which began on June 20, 2002, and runs through December 31, 2007.

A number of exceptions to the statutorily-mandated rate freeze are specified in the Clean Smokestacks Act, including one relating to a "[g]overnmental action resulting in significant cost reductions or requiring major expenditures, including, but not limited to, the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs." G.S. 62-133.6(e)(1)a. Duke interprets this section of the Act to have precluded it from seeking a deferral order from this Commission relating to GridSouth-related expenditures at any time prior to this proceeding because the governmental action which caused the expenditures occurred prior to the effective date of the Clean Smokestacks Act. Thus, according to Duke, these costs could not have been deferred prior to this proceeding because the governmental action which resulted in the expenditures did not occur during the rate freeze period. On the other hand, the Attorney General argued that the deferral Duke seeks in this case is prohibited by the Clean Smokestacks Act unless the Commission finds that such deferral was permitted by one or more of the exceptions set forth G.S. 62-133.6(e)(1).

The Commission concludes that Duke and the Attorney General have both misinterpreted the literal language of the statute and the intent of the General Assembly. According to G.S. 62-133.6(e), "the base rates of the investor-owned utilities shall remain unchanged from the date on which this section becomes effective through December 31, 2007." G.S. 62-133.6(e)(1) further provides that "the Commission may, consistent with the public interest," "[a]llow adjustments to base rates, or deferral of costs or revenues, due to one or more of the following conditions occurring during the rate freeze period . . . " Thus, the literal language of G.S. 62-133.6(e)(1) provides that (1) there shall be no change in base rates during the rate freeze period and that (2) adjustments to base rates or deferrals of costs or revenues during the rate freeze period may occur in the event that one of the four specified exceptions to the rate freeze exists.

In this case, the Commission is faced with a request that costs incurred prior to the rate freeze period as the result of a governmental action that occurred before the rate freeze period be deferred and amortized to rates after the end of the rate freeze period. This request does not implicate either of the prohibitions set out in G.S. 62-133.6(e)(1). First, nothing about the relief requested by Duke in any way involves a rate change occurring during the rate freeze period. Secondly, nothing about Duke's request would allow a deferral of costs incurred during the rate freeze period.[1] Since nothing in the statutory language bars the Commission from allowing a rate change after the rate freeze period resulting from costs incurred before the rate freeze period, the Commission is not barred from considering Duke's request on statutory grounds.

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[1] A portion of the AFUDC accumulated on the balance of the GridSouth costs was capitalized during the rate freeze period. Allowing the deferral and recovery of these costs might be deemed tantamount to allowing the deferral of costs incurred during the rate freeze period despite the fact that the underlying governmental action did not occur during the rate freeze period. The Commission's decision does not run afoul of any such interpretation of G.S. 62-133.6(e)(1)a, however, since the Commission has refused to allow the deferral of post-June, 2002, AFUDC on the balance of GridSouth costs as of that date. Similarly, by requiring the amortization period to begin as of June, 2002 without allowing any adjustment to rates, the Commission's decision does not contravene the language or the intent of G.S. 62-133.6(e)(1), since North Carolina retail rates have not and will not under the Commission's order pay rates that include the costs amortized during the initial five years of the Commission-approved amortization process.

The Commission's analysis is fully consistent with the purpose of the Clean Smokestacks Act, which was intended to require the affected utilities to address all costs incurred during the rate freeze period using revenues derived from existing rates and to require that rates remain unchanged during the initial portion of the compliance period. As a result of the general prohibition against establishing prospective rates so as to allow the recovery of prior period costs, Utilities Commission v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977), most rate changes based on pre-rate freeze costs are now barred by ordinary ratemaking principles. However, given that the GridSouth costs at issue here are multi-period costs of a type that are typically recovered over time, allowing the deferral and amortization of such pre-rate freeze costs does not run afoul of this prohibition. Thus, the Commission's decision with respect to the issue of the lawfulness of Duke's request to defer and amortize GridSouth-related costs is fully consistent with the rate freeze provisions of the Clean Smokestacks Act and ordinary ratemaking principles.

Although one could argue that entertaining Duke's request to defer and amortize GridSouth-related costs would be unlawful because the effect of the rate freeze provisions of the Clean Smokestacks Act is to require utilities to use existing, frozen rates to accommodate all costs (including those incurred both prior to and during the rate freeze period) except for those that are encompassed within the four exceptions set out in G.S. 62-133.6(e)(1), that interpretation is inconsistent with the relevant statutory language. On the contrary, the literal language of the statue simply bars rate changes or the deferral of costs or revenues based on events occurring during the rate freeze period unless one of the four exceptions set out in G.S. 62-133.6(e)(1) exists. The statute simply does not address either post-rate freeze rate changes or deferrals of pre-rate freeze costs. Any attempt to construe G.S. 62-133.6(e)(1) to bar otherwise permissible post-rate freeze rate changes or deferrals based on pre-rate freeze costs would import a gloss into the rate freeze statute that lacks support in its literal language.

One could also argue that the decision of the North Carolina Court of Appeals in Utilities Commission v. Carolina Utility Customers Association, Inc., 163 N.C. App. 46, 592 S.E. 2d 221 (2004), dis. rev. den., 358 N.C. 739, 602 S.E. 2d 683 (2004) (CUCA) precludes Duke from requesting and the Commission from granting the deferral of and subsequent amortization of the GridSouth expenditures to rates as a matter of law. The Commission disagrees. In CUCA, the Court of Appeals addressed the effect of the rate freeze provisions of the Clean Smokestacks Act on CUCA's request for a rate investigation based on alleged overearning occurring prior to the effective date of the Clean Smokestacks Act. In its complaint, CUCA urged the Commission to review and, if necessary, adjust Duke's rates because Duke was earning a return substantially in excess of the return that the Commission found reasonable in Duke's last general rate case. After reviewing the relevant provisions of the Clean Smokestacks Act, the Court of Appeals held that the Commission was precluded from ordering a change in Duke's rates because CUCA failed to allege that Duke's excessive earnings occurred during the rate freeze period as required by G.S. 62-133.6(e)(1)d. Any rate reduction resulting from alleged over-earning would, by virtue of the date on which CUCA made its filing, have necessarily had to be implemented during the rate freeze period. As a result, the Court of Appeals held that the requested relief could only be granted in the event that one of the four exceptions to the rate freeze existed. Since CUCA did not allege or prove that the factual prerequisites necessary to trigger the applicability of one of the four exceptions to the rate freeze existed, the Court of Appeals affirmed the Commission's dismissal of CUCA's petition.

The Commission has carefully reviewed the facts in the present case and believes that they are readily distinguishable from those at issue in CUCA. In this case, the Commission is faced with a request that costs incurred before the beginning of the rate freeze period as a result of a governmental action that antedated the effective date of the Clean Smokestacks Act be deferred and included in rates after the end of the rate freeze period. By contrast, CUCA sought a change in rates during the rate freeze period based upon alleged over-earnings that occurred prior to the effective date of the Clean Smokestacks Act. The relief requested by Duke in this case does not in any way involve a request for a rate change occurring during the rate freeze period, making it very different from the circumstances at issue in CUCA.

For all of these reasons, the Commission concludes that the Clean Smokestacks Act does not control the circumstances under which Duke may request and the Commission may grant a request to defer and amortize GridSouth-related costs. As a result, Duke's request to defer and amortize GridSouth-related costs should be evaluated under the usual principles applicable to deferral requests rather than being either barred by G.S. 62-133.6(e) or required to fit within the confines of one of the four exceptions to the rate freeze enacted as part of the Clean Smokestacks Act. However, as noted in Footnote 20, any Commission decision addressing the details of Duke's proposal must comport with the Clean Smokestacks Act.

The Commission has long allowed expenses incurred in certain situations to be deferred and amortized over an extended period to reflect the fact that these costs benefit all present and future customers. Utilities Commission v. Edmisten, 291 N.C. 451, 232 S.E. 2d 184 (1977). Classic examples of this principle are reflected in the well-established practice of deferring and amortizing storm restoration and abandoned plant costs over multi-year periods. See e.g., Utilities Commission v. Thornburg, 325 N.C. 463, 383 S.E. 2d 451 (1989). The Commission has generally decided requests for the deferral and amortization of specific cost items by examining whether the costs in question are unusual and material and whether allowing the deferral and amortization request is equitable, taking into account the equities for both shareholders and customers. When analyzed according to the Commission's usual tests, allowing deferral and amortization of the GridSouth-related costs at issue here is consistent with prior Commission decisions, assuming that appropriate modifications are made to Duke's proposal.

The costs in question are clearly quite unusual in that their incurrence resulted from Duke's attempts to comply with FERC orders. FERC orders of the magnitude of Order No. 2000 clearly are not routine events. It is difficult to think of another FERC order that resulted in the perceived necessity for the formation of an entirely new FERC-jurisdictional entity by a date certain. Although Order No. 2000 did not mandate RTO formation in so many words, FERC clearly intended to achieve nationwide RTO formation to the extent possible on a "voluntary" basis. Duke had no choice except to attempt to comply with Order No. 2000. Nothing in the present record suggests that Duke's efforts to comply with Order No. 2000 through the formation of GridSouth or its subsequent decision to suspend and then terminate the GridSouth effort were in any way unreasonable or imprudent. Instead, the evidentiary record clearly establishes that Duke's decision to proceed with the formation of GridSouth and the Company's subsequent decision to suspend and then terminate GridSouth-related activities were both reasonable and prudent given the circumstances existing at the time that those decisions were made. As a result, the costs in question are clearly unusual and not part of the ordinary cost of providing service. In addition, these costs are multi-period in nature; had GridSouth become a functional RTO, the majority of these costs would have been capitalized and recovered over time.

Furthermore, the amounts at issue here are clearly material. The requested deferral involves costs that are comparable to the amount of other deferrals that the Commission has approved in the past. For example, the Commission allowed the deferral of $15.4 million in Docket No. E-2, Sub 894; $23.5 million in Docket No. E-2, Sub 843; $39.8 million in Docket No. E-2, Sub 699; and a combined total of $23.5 million in Docket No. E-7, Sub 460. Although the Commission's analysis in each case was fact-specific, these decisions do suggest that the Commission has been willing to deem amounts similar to that at issue here to be material. Furthermore, while Duke earned a healthy return on its North Carolina retail rate base during the interval following the suspension of the GridSouth project according to contemporaneous "Quarterly Review" reports published by the Commission, that fact alone does not preclude allowance of the deferral request given the unusual nature of the costs at issue here. The level of a utility's earnings is certainly relevant to the Commission's evaluation of a request that costs be deferred and amortized to rates, since a high level of earnings may signal that the utility is able to accommodate the costs sought to be deferred and amortized under existing rates. On the other hand, given the magnitude of the costs in question and the reasonableness and prudence of the decisions that led to their incurrence, the Commission concludes that the level of Duke's earnings should not constitute an absolute bar to the recovery of all GridSouth-related costs in this instance. The Commission has, however, taken the level of Duke's earnings into account in deciding to lengthen the amortization period to ten years (consistent with the Commission's abandoned plant decisions); to treat the amortization period as having begun in June, 2002; and to preclude the inclusion of post-June, 2002 AFUDC in the deferral and amortization process[1], since the effect of this decision is to require Duke to address a significant percentage of these GridSouth-related costs under the rates in effect prior to the effective date of this Order. In addition, the effect of this Order is to reduce Duke's base rates, a fact that also militates against a total disallowance of Duke's request to defer and amortize GridSouth-related costs in light of the Commission's decision to use a 10-year rather than a five-year amortization period. Thus, a decision to allow deferral and amortization of the GridSouth costs in question here under the terms and conditions stated in this Order is not inconsistent with the Commission's prior deferral decisions and is equitable for both shareholders and customers.

The Public Staff vigorously contends that the Commission should disallow Duke's request to defer and amortize GridSouth-related costs because it believes that the Commission would have required Duke to hold North Carolina retail customers harmless from the cost effects of GridSouth had the proposed RTO become fully operational. In addition, the Public Staff contends that approval of Duke's request inappropriately requires Duke's North Carolina retail customers to pay rates that include both the embedded costs of Duke's transmission assets and costs associated with the formation of GridSouth, producing a result that the Public Staff does not believe that the Commission would have countenanced had GridSouth ever become

[1] The inclusion of post-June, 2002, AFUDC might also be prohibited by the rate freeze provisions of the Clean Smokestacks Act, as discussed in Footnote 20.

operational. In support of this argument, the Public Staff points to the Commission's decisions with respect to similar issues in Docket No. E-22, Sub 418, in which the Commission allowed DNCP to transfer operational control of its transmission assets to PJM. Although there are certainly similarities between this case and Docket No. E-22, Sub 418, there are also important differences resulting from the fact that the GridSouth participants suspended and then terminated efforts to form GridSouth before it became operational. Acceptance of the Public Staff's arguments involves a degree of speculation about what the Commission would have done in a subsequent transfer proceeding with which the Commission is uncomfortable. In the absence of definitive knowledge about the final structure of GridSouth, a cost-benefit study that was subjected to testing in an adversary proceeding, and similar evidence, it is simply not possible for the Commission at this point to know what it would have done in a GridSouth-related proceeding conducted pursuant to G.S. 62-111(a). Although the Public Staff points to the SEARUC cost-benefit study as evidence that GridSouth was never cost-effective, the results of that study did not become available until after the GridSouth participants suspended their formation efforts in June, 2002. Furthermore, while the Public Staff is correct in pointing out that the Commission would have likely adopted conditions intended to protect North Carolina retail ratepayers as part of any order allowing Duke to transfer operational control of its transmission assets to GridSouth, we cannot determine what those conditions would have been at this late date. Thus, the Commission is not persuaded by the Public Staff's arguments in reliance on the Commission's decision in Docket No. E-22, Sub 418.

The nature and scope of the exact terms and conditions of the deferral and amortization of any item of cost are committed to the Commission's sound discretion. Among other things, the Public Staff argued that the Commission should refuse to allow the inclusion of any GridSouth-related costs in rates in the exercise of its discretion because Duke failed to seek approval to defer these costs at an earlier time, because Duke did not begin amortizing GridSouth-related costs at the time that the GridSouth participants suspended work on the formation of GridSouth, because Duke incurred costs relating to GridSouth prior to obtaining Commission authorization to defer GridSouth-related costs, and because approval of Duke's request to defer and amortize GridSouth-related costs would require retail customers to pay an inappropriately large portion of the costs in question despite the fact that they were primarily incurred for the purpose of improving the operation of wholesale bulk power markets. In the Commission's view, some of these arguments are unpersuasive and others are more appropriately directed to the terms and conditions under which deferral and amortization of GridSouth-related costs should be allowed rather than to whether deferral and amortization should be permitted at all.

Although the evidentiary record establishes that Duke and the other GridSouth participants began to incur GridSouth-related costs before GridSouth had been approved by either the FERC or the Commission, that fact should not, in the Commission's opinion, bar deferral and amortization of some level of GridSouth-related costs in this proceeding. According to Order No. 2000, FERC-jurisdictional public utilities were required to make their compliance filings by October 1, 2000, and to have any new RTO proposed in those compliances filings up and running by December 1, 2001. The undisputed evidence reflects that the GridSouth participants began to incur costs associated with the formation of the proposed RTO prior to FERC and Commission approval in an effort to meet the deadlines set out in Order No. 2000 and that compliance would not have been possible except for the incurrence of these costs. In addition, it is not generally necessary for utilities to obtain regulatory approval before incurring similar items of cost. Although G.S. 62-101(a) requires the issuance of a certificate before a utility can begin to construct new transmission lines over a certain voltage and G.S. 62-110.1(a) requires utilities to obtain a certificate before incurring costs associated with new generating facilities, the same is not true of RTO-related costs. Instead, such costs are generally addressed through the ordinary ratemaking process. As a result, the fact that Duke failed to seek and obtain FERC and Commission approval before beginning to incur GridSouth-related costs is not a bar to consideration of Duke's request in this proceeding.

The record does clearly reflect that Duke failed to seek Commission approval to defer and amortize these GridSouth-related costs prior to initiating this proceeding and that Duke has yet to begin amortizing them. Despite the fact that these costs did not fit within the scope of the "governmental action" exception to the Clean Smokestacks Act rate freeze, nothing prohibited Duke from at least bringing this issue to the Commission's attention at an earlier time. Although the Company argues that the FERC allowed the deferral of these costs, FERC accounting orders are not binding on this Commission for retail ratemaking purposes. Furthermore, the Commission agrees with the Public Staff that, as a matter of ordinary practice, amortization of deferred costs should begin as soon as the relevant regulatory asset is or should be established. As a result, the Commission concludes that it would have been preferable for Duke to have signaled to the Commission at an earlier time that it intended to seek a deferral and amortization of these GridSouth-related costs and that the Company should have begun to amortize these GridSouth-related costs at the time that it suspended its RTO formation efforts in June, 2002. Thus, the Commission has structured the deferral and amortization approach it has approved in this proceeding so as to lengthen the amortization period; to require that amortization be deemed to have begun in June, 2002; and to decline to allow the deferral and amortization of post-June, 2002, AFUDC in rates. By adopting this approach, the Commission believes that it has acted consistently with its prior decisions concerning plant abandonment issues and has required an appropriate sharing of these GridSouth-related costs among retail ratepayers, wholesale customers, and shareholders.

The fact that the primary purpose of the FERC's efforts to facilitate RTO formation was to improve the operation of the wholesale market does not bar approval of a request to defer and amortize the costs at issue here either. Although the large majority of the energy sold by Duke at retail is generated in utility-owned facilities, the Company does purchase power on the open market for resale to its retail customers. Furthermore, the level of a utility's involvement in the wholesale market affects the amount of generation, transmission, and other costs assigned to retail customers through the ordinary jurisdictional allocation process. For that reason, singling out the industrial class to bear all allowable GridSouth-related costs, as recommended by the Attorney General, is not appropriate. On the other hand, the fact that Duke's wholesale customers would, in all likelihood, obtain greater benefits from improved wholesale markets than Duke's retail customers does suggest that the amount of GridSouth-related costs included in retail rates should be limited. The approach to the deferral and amortization of these GridSouth-related costs approved by the Commission accomplishes this result by substantially reducing the annual amount included in Duke's cost of service for retail ratemaking purposes.

As a result, the Commission concludes, for the reasons stated above, that the deferral and amortization period should be deemed to have begun in June 2002; that the proposed amortization period should be extended to 10 years; and that no carrying charges accruing after June, 2002 should be included in the deferral and amortization process. More specifically, the Commission finds and concludes that it is appropriate to include $2,906,000 as an operating expense in Duke's cost of service to amortize the North Carolina retail portion of GridSouth investment incurred prior to the end of June 2002, over a 10-year period beginning June, 2002. In recognition of the unique facts and circumstances at issue here, the Commission has essentially approved the creation of a regulatory asset *nunc pro tunc* to June, 2002, and limited the approved amortization to costs that were incurred prior to the end of June, 2002. This treatment of GridSouth costs for deferral and amortization is lawful, generally consistent with the traditional treatment of abandoned plant costs by the Commission, and fair to both shareholders and ratepayers.

The Commission has carefully considered the positions of the Public Staff, the Attorney General, and Duke in reaching this decision. The situation surrounding the GridSouth participants' efforts to form an RTO is unique. In fact, the Commission believes that this issue is essentially "one of a kind." The Commission concludes that Duke acted prudently in pursuing GridSouth, and that it acted prudently in suspending and later abandoning GridSouth as well. Duke's involvement in the attempted formation of GridSouth clearly represented an effort to comply with Order No. 2000 in a manner that was responsive to the interests of North Carolina retail customers. The Commission also agrees with the Public Staff and the Attorney General that, with the benefit of hindsight, Duke should have sought the Commission's approval to create a regulatory asset relative to the GridSouth development costs and to have begun amortizing these costs at an earlier time. However, Duke incurred GridSouth costs in a time of rapidly changing regulatory requirements. It would have been difficult for Duke to know, at that time, that the GridSouth effort would not continue to evolve so that it became acceptable to both FERC and the Commission or that, on the contrary, the time had come to request deferral and amortization. In essence, the Commission has treated the GridSouth cost issue in this proceeding as tantamount to an abandonment loss. In such instances, the Commission has allowed the recovery of prudently incurred costs over an appropriate period of time without allowing a recovery on the unamortized balance (Duke has not requested to be allowed to include a return on the unamortized balance of GridSouth-related costs in this proceeding). The application of these principles in the plant abandonment context has been upheld on appeal, Utilities Commission v. Thornburg, 325 N.C. 463, 385 S.E. 2d 451 (1989), and the Commission sees no reason why they are not applicable to the GridSouth-related costs at issue here. Thus, the Commission concludes that the ratemaking treatment of GridSouth costs set forth in this Order is reasonable and appropriate for purposes of this proceeding.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 35

The evidence relating to this finding and conclusion is found in the testimony of CIGFUR III witness Phillips and Duke witness Bailey.

The Company's Rider IS is a special rate for interruptible service to nonresidential customers. CIGFUR III, through witness Phillips, proposed a number of changes to Rider IS and requested that the Commission consider those changes in this docket. First, witness Phillips proposed that the method of calculating the credit for Rider IS customers, which currently is $3.50 per kW, be changed to provide a substantially larger credit, based on either a sharing of 50% of the "avoided cost" of the interruptible load, which would imply a credit of $8.00 per kW, or an "equivalent peaker" approach, which would yield a credit of $6.75 per kW. Second, witness Phillips proposed that the Company be required to lift the suspension of Rider IS and to open it to new load, using either the 1,100 MW cap established in 1991 or a cap of at least one-half that amount (550 MW) as the limit on allowable participation in Rider IS. Finally, witness Phillips disputed the Company's position that Rider IS should be permitted to remain as it is until the Company's application in Docket No. E-7, Sub 831 for approval of its "Save-a-Watt" Energy Efficiency Program can be considered.

Company witness Bailey testified in rebuttal to witness Phillips' testimony. Witness Bailey presented the Company's position that issues related to Rider IS and all other existing DSM programs should be considered in Duke's pending Docket No. E-7, Sub 831, rather than in this rate case. Witness Bailey stated that the Commission had expressed its intent, in bifurcating the Energy Efficiency Docket from this docket, to take up the Energy Efficiency Docket next year after the rulemaking implementing Senate Bill 3 is completed, and there will be no significant harm or delay in waiting until then to consider such issues.

With respect to witness Phillips' recommendations for changes to Rider IS, witness Bailey first pointed out that witness Phillips' proposal to base the credit for Rider IS customers to one-half of the demand charge for firm service is without merit because it does not take account of the fact that the demand charge is based on embedded costs for existing resources, which are unavoidable costs. Turning to witness Phillips' "equivalent peaker" method for sizing the credit, witness Bailey stated that such an approach fails to consider the market demand for interruptible products, program attributes that affect the value of the program to the utility (such as length and frequency of interruptions), and customers' perceptions of the value of the program. Witness Bailey responded to witness Phillips' recommendation that Rider IS be reopened by stating that the Company believes its decision to continue all existing DSM programs in their present state until the Energy Efficiency Docket is decided is correct.

The Commission agrees with Duke that changes to Rider IS should be considered in Docket No. E-7, Sub 831, together with the other proposals in Duke's Save-a-Watt filing. Having bifurcated the Save-a-Watt docket from this general rate case proceeding, consideration of issues relating to Rider IS in Docket No. E-7, Sub 831, where the Commission can consider the full complement of EE and DSM measures, is appropriate. Additionally, considering Rider IS in isolation has limited benefit, since whatever decision the Commission might make in this docket on Rider IS would probably have to be revisited during the Commission's consideration of Duke's application in Docket No. E-7, Sub 831. The Commission, therefore, concludes that it should defer consideration of changes to Rider IS to Docket No. E-7, Sub 831 and transfer to that docket, in addition to the consideration of the new programs proposed by Duke, the issue of what changes, if any, are appropriate to existing DSM and EE programs such as Rider IS.

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 36

The evidence supporting this finding of fact and conclusion is found in Duke's verified Application and Duke's Form E-1 Rate Case Information Report, the Stipulation, the testimony and exhibits of Duke witnesses Bailey and Yarbrough, the Attorney General's October 15, 2007 Statement of Position, and the entire record in this proceeding.

Duke argued that there is no reason to change the definition of "customer" in Leaf A or the Denial and Discontinuance provisions of Leaf G in the Company's tariffs. The Attorney General has argued that the definition of "customer" should be changed so that it excludes users that are not explicitly named on the account and that the provisions regarding denial and discontinuance of service should be changed to eliminate provisions that the Commission has previously approved. On the other hand, Duke argued that there is no evidence in the record to support the changes proposed by the Attorney General and that the irrefutable evidence establishes that the current language is working well and strikes the appropriate balance between maintaining the Company's ability to maximize collections from unscrupulous users of electric service while avoiding undue harm to other customers.

Duke asserted that the Company's definition of the term "customer" has not caused confusion or complaint from customers. Instead, the Company maintained that it is a tool that Duke and other utilities in the Southeast use to subject the user of the service to the Rate Schedules, Service Regulations, and the Commission's Regulations for the purpose of mitigating nonpayment problems and reducing energy theft. Company witness Yarbrough explained that the definition of "customer" in the Service Regulations is applied so as to make the user of the service responsible for paying for it in cases where the user and the customer of record are not the same person, such as when the customer of record is deceased or when there is no customer of record (such as in cases of energy theft). Witness Yarbrough testified that a more restrictive definition could make it difficult to police fraudulent and abusive evasion of bills for service.

Duke contended that the provisions in Leaf G, like the Commission's policy on deposits set forth in Rule R12-1, are designed "to avoid, to the extent practicable, the creation of a burden arising from uncollectible bills which would have to be borne ultimately by all the utility's ratepayers." Duke explained that the provisions of Leaf G are designed, like deposits, to deal with attempts to avoid payment of bills rendered by a utility with an obligation to provide service, and that those provisions, in turn, save paying customers money. According to Duke, the Attorney General presented Yarbrough Cross-Examination Exhibit No. 5, which purported to show 127 undesignated, "disputed bill" informal complaints raised with the Public Staff in the nine-month period from January through September 2007, in an effort to establish the existence of a problem. However, Company witness Yarbrough noted that there were only 127 such informal complaints out of approximately 11.7 million bills, and not a single one of those 127 complaints resulted in a formal customer complaint filed with the Commission challenging the existing policy. Duke emphasized that those complaints that have been brought to the Commission in recent years have been resolved in favor of Duke, either by withdrawal or dismissal following hearing. Duke further noted that neither the Public Staff nor any other party to this proceeding advocates the Attorney General's proposed changes. The Service Regulations at issue have been in place in essentially the same form since 1944, and according to Duke, the

Company's policy has worked well and continues to serve its customers well. Duke also pointed out that the Commission continues to enforce regulations of a similar nature in cases involving other utilities subject the Commission's jurisdiction. Delaney v. Progress Energy Carolinas, Docket No. E-2, Sub 905 (Sept. 20, 2007) (Commission finding resident jointly responsible with account holder for past due electric bills). As a matter of logic and policy, Duke concluded that there is no compelling reason to change either the definition of "customer" or the provisions for denial and discontinuance of service, so the Company asked that the Commission approve the Service Regulations as set forth in Exhibit A to the Stipulation.

Duke believes that changing the definition of "customer" and/or the provisions for denial and discontinuance of service invites attempts to avoid payment and could unjustly enrich those who refuse to pay the bills that they owe. Duke argued that the changes proposed by the Attorney General to these sections of the Company's Service Regulations could add the unnecessary and expensive step of requiring Duke to seek restitution from an electricity user who has not paid amounts owed. Seeking restitution can be a time consuming and expensive process for both the Company and the user and is unnecessary under the current system. For the 2006 test year, Duke reported $18.8 million in uncollectible expenses (system-wide), which was reduced to a net expense of approximately $10.5 million due to Duke's collection efforts under the existing regulations. (Duke's Late-Filed Exhibit No. 1, filed October 26, 2007.) Duke maintained that the current system, using the existing definition of "customer", saves all involved from the potential for costly litigation while providing the Company and its other paying customers with the collections to which they are entitled.

The Attorney General responded that Duke's service regulations establish important terms under which consumers must contract with Duke, a monopoly provider, in order to receive and pay for essential electric service. Therefore, the service regulations should comport with North Carolina laws governing contracts and debt collection practices. The Attorney General argued that, as applied by Duke, the service regulations are contrary to North Carolina law in three respects. First, Duke applies the regulations to hold Customer A responsible for former Customer B's electric bill even though Customer A has no legal obligation to pay Customer B's bill. Second, Duke enforces the above practice by transferring Customer B's unpaid bill to Customer A's account and threatening to terminate customer A's electric service if Customer B's bill is not paid. Third, Duke improperly represents the extent of Customer A's obligation to Duke and improperly discloses information about Customer B's debt to Customer A.

Specifically, the Attorney General proposed the five following findings:

1. For the purpose of defining and enforcing the payment obligations of persons who receive electric service, the provisions of Section XII.8 and XII.6 in Duke's Service Regulations are overly broad and inconsistent with North Carolina contract law.

2. There is no legal authority or rational basis for Duke to require or receive information from applicants about the names, relationship to the applicant, and Social Security numbers of other adults living in the applicant's household.

3. There is no legal authority for Duke to collect or attempt to collect the unpaid bill of one customer from another customer who is not legally obligated to pay the bill.

4. There is no legal authority or equitable basis for Duke to transfer the unpaid bill of one customer to the account of another customer who is not legally obligated to pay the bill. Further, such bill transfers create the potential for unauthorized disclosure of one customer's account information to another customer, misunderstandings by customers as to the extent of their payment obligations, and improper denial or disconnection of electric service.

5. For the purpose of identifying the person(s) who are legally obligated to pay for electric service, the definition of "customer" in Duke's service regulations is overly broad and inconsistent with North Carolina contract law.

The Attorney General's Brief offers a lengthy, detailed argument as to why the Attorney General's proposed changes to Duke's service regulations are necessary to make Duke's service regulations comport with the Attorney General's understanding of North Carolina law relating to contracts, fair debt collection practices and public utilities. In his Brief, the Attorney General noted that Regulation XII.8 has its origins in a similar provision that was addressed in connection with the reconnection of service and allowed denial of service for indebtedness of a member of the family at the same premises. The provision was moved to Section XII in 1994 and modified to allow denial of service to a member of the household or business at any premises served by Duke.

The Attorney General observed that Duke applies Regulation XII.8 not only to deny service at the time of application, but also to disconnect service to an existing customer of record if another member of the household was indebted to Duke at the time the application for service was made. It is Duke's practice to transfer the indebtedness from the third party to the customer's bill. Witness Yarbrough testified that Duke sends a letter to the customer prior to making the transfer, notifying him of the third person's indebtedness. If the debt is not paid or a payment arrangement entered into and the customer does not respond to the letter within 10 days, then Duke transfers the bill to the customer's account.

The Attorney General's proposed changes to the current, stipulated Service Regulations are discussed in his Proposed Order and the reworded portions are included in its Attachment A to that Proposed Order.

No other parties responded to the Service Regulations issues raised by the Attorney General.

The Commission agrees with Duke that, as a matter of logic and policy, there is no compelling reason to change the definition of "customer" or the provisions for denial and discontinuance of service. No other party has expressed support for the Attorney General's position. There have been very few complaints from Duke's customers relating to the issues raised by the Attorney General, and the current service regulations have made it easier and less costly for Duke to collect amounts owed by customers.

During the hearing, Duke witness Yarbrough noted that any time customers feel that Duke has not appropriately interpreted any regulation, they have the right to have Duke's interpretation reviewed with the Public Staff. And when there continues to be a dispute, the customer has the right to file a formal complaint with the Commission. The Commission is of the opinion that this set of procedures provides ample protection for Duke's residential customers in the event that Duke fails to apply its existing service regulations in an appropriate manner.

Duke's practice is to deny or disconnect current service to a customer for a past due and unpaid balance for electric service incurred by a member of the customer's household if the delinquent member resides with or will reside with the customer at the time the customer applies for service. In lieu of denial or disconnection of service, Duke will transfer the delinquent obligation to the account of the current customer for collection. The Attorney General asserts that this practice violates North Carolina law because it permits Duke to hold one person liable for payment of goods and services based on an implied contractual obligation where there is an express contract with another person to pay for the same goods and services. The Attorney General cites Vetco Concrete Company v. Troy Lumber Company, 256 N.C. 709, 124 S.E. 2d 905 (1962) as support for this position. In Vetco, the Supreme Court of North Carolina found that a supplier's express contract with a purchaser of materials precluded the supplier from pursuing payment from a third-party lumber company that had used some of the materials. The Court held that, where an express contract exists, an implied contract is precluded with reference to the same subject matter.

The Commission has carefully reviewed the Vetco decision, as well as each of the additional cases cited by the Attorney General.[1] A close reading of each of those cases leads the Commission to conclude that they are inapplicable to the present situation for the following reasons. First, in this proceeding, unlike in those cases, there is an express contract, i.e., the service agreement, rather than an implied agreement that provides for the denial of service if suitable arrangements are not made for the recovery of the bills in question. The service agreement expressly incorporates those sections of Duke's Commission-approved regulations that permit the discontinuation of service to the applicant unless arrangements are made to satisfy the debt of the delinquent obligor into that agreement. Second, in this proceeding, unlike in those cases, the third-party applicant actually receives new consideration in the form of future service in exchange for her agreement to pay the additional expenses.

In each of the cases upon which the Attorney General relies, there is no evidence that the party that breached his duty to pay sought to continue receiving the product for which he failed to pay with the assistance of the party contending before the court that he should not be required to pay the delinquent party's debt. The Commission understands that the Attorney General might dispute this characterization. However, it is beyond contravention that, without the applicant's assistance, the debtor would be unable to receive utility service without making arrangements to pay his past due bill.

[1] Robinson, Bradshaw & Hinson, PA v. Smith, 129 N.C. App. 305, 498 S.E. 2d 841, dis. rev. den., 348 N.C. 695, 511 S.E. 2d 649 (1998); N.C. Baptist Hospitals v. Franklin, 103 N.C. App. 446, 405 S.E. 2d 814, dis. rev. den., 330 N.C. 197, 412 S.E. 2d 58 (1991); G&S Business Services v. Fast Fare, Inc., 94 N.C. App. 483, 380 S.E. 2d 792, dis. rev. den., 325 N.C. 546, 385 S.E. 2d 497 (1989).

The Attorney General has also argued that the applicant should not be responsible for the third-party's debts unless he knowingly assists the debtor in evading his obligation to make payment. It is axiomatic that an individual cannot escape his obligations by being willfully blind to that which is obvious. That is, "[a] man should not be allowed to close his eyes to facts readily observable by ordinary attention, and maintain for his own advantage the position of ignorance." State Farm v. Darsie, 161 N.C. App. 542, 548, 589 S.E.2d 391, 397 (2003), dis. rev. den., 358 N.C. 241, 594 S.E. 2d 194 (2004). Duke's policy places the applicant on notice that she could be responsible for the debts of a third party co-resident when she applies for service. It is thus incumbent upon her to inquire of the potential co-resident to determine if the co-resident owes an outstanding debt to Duke. Should she choose not to make such an inquiry, she cannot thereafter escape responsibility by pleading ignorance of the co-resident's debt. Moreover, if one accepts the postulate that the applicant has no legal obligation to support the debtor, by definition, the applicant is actively assisting the debtor to evade his responsibility because she has chosen not to make the debtor contractually and legally responsible for his share of the obligation by failing to require the debtor to be a joint applicant for service. If, however, there is an agreement "to share the utility bill between the parties," the applicant has legally agreed to assume the debtor's debt in order to qualify for service since the debtor will only be eligible for renewed service if she makes arrangements to settle his debt with the utility.

In addition to the aforementioned, the Commission believes that Deep Run Milling Company v. Williams, 60 N.C. App. 160, 163, 298 S.E.2d 205 (1982), a case which the Attorney General also cites, is supportive of Duke's position. In Deep Run, the Court of Appeals held that it was appropriate to hold a third-party spouse liable for debts that were legally incurred by her husband when the only express contract was between the debtor/husband and the vendor seeking payment. In that case, the Court examined the record and found that the wife actually received and used the product with knowledge of her husband's delinquency and by her express statements thereafter ensured payment. In that situation, the Court held that it was permissible to allow collection of the husband's express debt from the wife on an implied contract theory. In this case, a Commission-approved service agreement,[1] which incorporates the Service Regulations, provides notice that outstanding debts incurred by a potential household member prior to the execution of the service agreement must be satisfied before service can be provided.[2] Thus, the applicant effectively agrees to satisfy the debt in order to receive service and is thereby properly held accountable.

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[1] The utility may only impose such a requirement on the customer by Commission-approved regulation. See Commission Rule R8-22, which provides that "[a]ny utility may decline to serve a customer or prospective customer until he has complied with. . . the rules and regulations of the utility furnishing the service, provided such rules and regulations have been approved by the Commission." (emphasis added.) See also Horton v. Interstate Telephone and Telegraph Company, 202 N.C. 610, 163 S.E. 2d 694 (1932) where the Supreme Court held that a utility could not deny service to an otherwise eligible customer based upon a policy which had not been approved by the Commission.

[2] According to witness Yarbrough, the Commission was provided detailed examples of Duke's collection practices in 1994. See Order Approving Revised Service Regulations, Docket E-7, Sub 541, March 30, 1994.

The Attorney General also argued that Duke's practices violate the North Carolina Debt Collection Practice Act.[1] The Commission determines that the North Carolina Debt Collection Practice Act was not designed to shield a debtor's efforts to fraudulently procure a service to which he is not entitled by using an applicant who will unknowingly become responsible for the debtor's debt. In that situation, the Commission believes that disclosure to the unwitting applicant to prevent her from becoming a victim of the debtor's fraud[2] is authorized.

Finally, the Attorney General argues that Duke's actions in requiring a third party to guarantee the debt of the debtor violates G.S. 22-1, which provides that:

> No action shall be brought whereby to charge an executor, administrator or collector upon a special promise to answer damages out of his own estate or to charge any defendant upon special promise to answer the debt, default or miscarriage of another person, unless the agreement upon which such action shall be brought, or some memorandum or note thereof, shall be in writing, and signed by the party charged therewith or some other person thereunto by him lawfully authorized.

According to the Attorney General, G.S. 22-1 requires Duke to have a written agreement from the applicant to be responsible for the third-party debt. Neither Duke nor any other party addressed this contention in their Briefs or Proposed Orders.

The Commission is not persuaded that Duke's practice of securing an oral agreement that incorporates terms requiring the applicant to be responsible for the co-resident's debt to qualify for service violates the Statute of Frauds. A written agreement is not required when the main purpose of the promisor is to procure some benefit for herself. Warren v. White, 251 N.C. 729, 112 S.E. 2d 522 (1960). In this situation, the primary purpose of the applicant in guaranteeing the debt of the debtor is not to absolve the debtor of the debt, but to ensure that the applicant qualifies to receive utility service. Thus, the Statute of Frauds does not apply in this type of situation. Similarly, even if the statute of frauds did apply, Duke could simply require each applicant to sign a written agreement which included the guarantee language.

After considering all of the evidence and the arguments in the Briefs and Proposed Orders, the Commission concludes that there is insufficient reason to order any changes to Duke's Service Regulations beyond those clarifications and refinements that are set out in the Stipulation. The evidence in the record demonstrates that the current language strikes an appropriate balance between maintaining the Company's ability to maximize collection efforts from users of electric service and avoiding practices that inappropriately harm any particular customer.

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[1] The North Carolina Debt Collection Practice Act prohibits unreasonable publication of information regarding a consumer's debt. G.S. 75-53.

[2] See the discussion of fraud in State v. Yarboro, 194 N.C. 498, 501-502, 140 S.E. 216, 217 (1927). "The phrase 'in cases of fraud' qualifies the word 'debt'; it signifies fraud in making the contract or in attempting to evade performance by the fraudulent concealment or disposition of property or other fraud devised for the purpose of defeating collection of the debt." (Emphasis added.)

EVIDENCE IN SUPPORT OF FINDING OF FACT AND CONCLUSION NO. 37

The Commission has previously discussed its findings and conclusions regarding the fair rates of return which Duke should be afforded an opportunity to earn.

The following schedules summarize the gross revenues which the Company should have a reasonable opportunity to collect, and the rates of return which the Company should have a reasonable opportunity to earn, based upon the determinations made herein. As reflected in Schedule I, Duke should be required to reduce its annual level of electric operating revenues by $286,924,000, based upon the adjusted test-year level of operations approved herein for Duke's North Carolina retail operations.

SCHEDULE I

DUKE ENERGY CAROLINAS, LLC

North Carolina Retail Operations
Docket No. E-7, Sub 828
STATEMENT OF OPERATING INCOME
For the Twelve Months Ended December 31, 2006
(000s Omitted)

Item	Present Rates	Approved Change	Approved Rates
Electric operating revenue	$3,971,696	$(286,924)	$3,684,772
Operating revenue deductions:			
Operations and maintenance expenses:			
Fuel used in electric generation	952,776		952,776
Non-fuel purchased power and net interchange	49,248		49,248
Wages, benefits, materials, etc.	1,043,004		1,043,004
Depreciation and amortization	495,499		495,499
General taxes	236,548	(9,583)	226,965
Interest on customer deposits	3,156		3,156
Income taxes	357,645	(108,608)	249,037
Amortization of investment tax credit	(6,213)		(6,213)
Total operating revenue deductions	3,131,663	(118,191)	3,013,472
Net operating income for return	$ 840,033	$(168,733)	$ 671,300

( ) Denotes decrease.

SCHEDULE II
DUKE ENERGY CAROLINAS, LLC
North Carolina Retail Operations
Docket No. E-7, Sub 828
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Twelve Months Ended December 31, 2006
(000s Omitted)

Item		Amount
Electric plant in service, including nuclear fuel		$15,103,463
Accumulated provision for depreciation and Amortization		(6,472,573)
Net electric plant in service		8,630,890
Materials and supplies		394,250
Working capital investment		148,717
Operating reserves		(320,091)
Accumulated deferred income taxes		(1,020,717)
Original cost rate base		$ 7,833,049
Overall rates of return:		
Present rates	10.72%	
Approved rates	8.57%	

SCHEDULE III
DUKE ENERGY CAROLINAS, LLC
North Carolina Retail Operations
Docket No. E-7, Sub 828
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Twelve Months Ended December 31, 2006
(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%	$3,681,533	5.83%	$214,633
Common equity	53.00%	4,151,516	15.06%	625,400
Total	100.00%	$7,833,049		$840,033
		Approved Rates – Original Cost Rate Base		
Long-term debt	47.00%	$3,681,533	5.83%	$214,633
Common equity	53.00%	4,151,516	11.00%	456,667
Total	100.00%	$7,833,049		$671,300

ELECTRIC – FILINGS DUE PER ORDER OR RULE

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed in these dockets on October 5, 2007, is hereby approved subject to the additional decisions set forth in this Order.

2. That Duke shall, as directed by further Order of the Commission addressing specific tariffs developed pursuant to this Order, adjust its rates and charges in accordance with the provisions of the Stipulation and this Order, effective for service rendered on and after January 1, 2008.

3. That Duke shall file within 10 days of the date of this Order a statement setting forth the calculation of the new rate to be used to capitalize the allowance for funds used during construction (AFUDC) which shall become effective on January 1, 2008, based upon the decisions reflected in this Order. Duke shall provide a brief explanation of each item entering into the calculation of said AFUDC rate and shall explain the mechanics of its AFUDC accrual procedures. Such information shall be provided in a format similar to that provided by Duke in its Item No. 24 Response included in its Form E-1 Rate Case Information Report filed in this proceeding. In addition, Duke shall also file a calculation and the underlying explanation of its currently effective AFUDC rate.

4. That Duke is hereby authorized to implement an adjustable Existing DSM Program Rider (EDPR) as provided in Paragraphs 11F-H of the Stipulation. The EDPR and the Company's DSM deferral account shall be subject to modification or elimination by the Commission, if appropriate, in either Docket No. E-7, Sub 831 or Docket No. E-100, Sub 113.

5. That Duke shall credit all future nuclear property insurance policy distributions to Account 228.1, Accumulated Provision for Property Insurance, unless specifically authorized by the Commission to change such accounting practice.

6. That Duke shall continue to file annual cost of service studies based on both the Summer Coincident Peak (SCP) and the Summer-Winter Peak and Average (SWPA) methodologies.

7. That no portion of any Environmental Compliance Costs directly assigned, allocated, or otherwise attributable to another jurisdiction pursuant to Paragraph 7D of the Stipulation shall be recovered from North Carolina retail customers, even if recovery of those costs is disallowed or denied, in whole or in part, in another jurisdiction.

8. That Duke's actual and proposed modifications and permitting and construction schedule under the Clean Smokestacks Act are adequate to achieve the emissions limitations set out in G.S. 143-215.107D.

9. That Duke Energy Corporation is hereby authorized, on a provisional basis, as part of its compliance with SFAS No. 158, to establish a regulatory asset in Account No. 182.3 with respect to Duke's apportioned share of the funded status of pension and other postretirement benefit plan obligations.

10. That the Public Staff is hereby requested to undertake a comprehensive examination and evaluation of Duke's and Duke Energy's practices and procedures with respect to the costing and funding of Duke's pension and OPEB obligations in a manner consistent with the findings and conclusions as set forth herein, and file a detailed report with the Commission setting forth its findings, conclusions, and recommendations. This report shall be filed not later than nine months from the date of this Order (or such other time as the Commission may subsequently establish by Order), in Docket No. E-100, Sub 112. The Public Staff is hereby authorized, in its discretion and as it deems advisable and necessary, to engage an independent accounting or consulting firm to conduct the examination and evaluation or provide consulting assistance to the Public Staff.

11. That the Commission will, pursuant to G.S. 62-80, reconsider one provision of the Merger Order entered in Docket No. E-7, Sub 795 on March 24, 2006. The Commission will specifically reconsider that provision in Regulatory Condition No. 76 (as discussed in conjunction with Finding of Fact No. 37 in the Merger Order and the Evidence and Conclusions in support thereof) which provides that:

> . . . Nor will any portion of the net merger savings attributed to shareholders by Duke Energy be eligible for recovery from North Carolina retail ratepayers in base rates, rate riders, or other cost recovery mechanisms set prospectively subsequent to consummation of the Merger. . . .

The Commission has preliminarily concluded that the provisions of the Merger Order will not produce a fair sharing of the benefits of estimated merger savings between ratepayers and shareholders and that, for that reason, Duke should be authorized to implement a 12-month rate increment rider to collect $80,459,000 from its North Carolina retail customers for the benefit of its shareholders. Pursuant to G.S. 62-80, the Parties to Docket Nos. E-7, Sub 795 and E-7, Sub 828 are hereby given notice and opportunity to be heard in response to the Commission's stated intent to reconsider the specified provision of the Merger Order. Initial comments on this matter on reconsideration shall be filed by all parties not later than Friday, January 11, 2008, and reply comments shall be filed not later than Friday, January 25, 2008. Such comments shall be filed in Docket Nos. E-7, Sub 795 and E-7, Sub 828. The Commission will then enter an Order on reconsideration.

12. That Duke shall establish a 10-year amortization schedule for $29,059,000 of GridSouth costs, and shall begin the amortization in June 2002, without the benefit of carrying charges after that date.

13. That consideration of changes to Rider IS shall be deferred to Docket No. E-7, Sub 831. In addition to the consideration of the new programs proposed by Duke, the issue of what changes, if any, are appropriate to existing demand side management (DSM) and energy efficiency (EE) programs, such as Rider IS, shall be transferred to Docket No. E-7, Sub 831.

14. That the Attorney General's request for amendments to Duke's service regulation in addition to those reflected in the stipulated Service Regulations are hereby denied, and Duke's Service Regulations, attached as Exhibit A to the Stipulation, are hereby approved without change, subject to further Orders of the Commission.

15. That Duke shall file, within 10 days of the date of this Order, a statement setting forth the test-period annualized amount of depreciation expense, with the actual amount and annualization adjustment shown separately, included as an operating revenue deduction under the provisions of the Stipulation. Such information is required to ensure compliance with G.S. 62-133(b)(3) and shall be presented both on a total-company and a North Carolina retail basis.

16. That the Chief Clerk shall serve a copy of this Order on the parties to Docket Nos. E-7, Subs 795, 828, and 829 and Docket No. E-100, Sub 112.

ISSUED BY ORDER OF THE COMMISSION.

This the 20th day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Bb122007.01

Commissioners Robert V. Owens, Jr. and Lorinzo L. Joyner dissent, in part, with regard to the GridSouth ratemaking treatment.

DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 829
DOCKET NO. E-100, SUB 112
DOCKET NO. E-7, SUB 795

COMMISSIONER ROBERT V. OWENS, JR., DISSENTING IN PART: I would have flatly rejected Duke's request to recover any GridSouth development costs in the NC retail rates established by the Commission in this proceeding. I strongly believe that the Majority erred with respect to its decision on this issue for several reasons.

First, the FERC is the regulatory agency that caused the GridSouth development costs to be incurred and then a shift in that agency's policy caused the GridSouth project to be canceled. Further, RTO formation and the transmission of power in the wholesale market is under the FERC's jurisdiction. Therefore, Duke should have gone to the FERC to request recovery of all GridSouth development costs from transmission customers before coming to this Commission and requesting that NC retail ratepayers pay over 70% of such costs. Absent even a request by Duke and a ruling by the FERC on this matter, I fail to understand why the Majority feels compelled to include GridSouth costs in NC retail rates.

Second, under any reasonable interpretation of accounting principles and Commission Rule R8-27, Duke should not now be requesting, and the Majority should not now be approving, the deferral and amortization of costs that were incurred prior to mid-2002. In addition, the Majority states that the Commission has generally decided deferral and amortization requests on the basis of whether the costs in question are unusual and material, and considering whether the request is equitable. In discussing materiality, the Majority acknowledges that Duke earned a healthy return in the aftermath of the suspension of the GridSouth project according to the

"Quarterly Review" reports published by the Commission. However, what the Majority fails to mention is that Duke earned 13.23% on common equity for the 12 months ended December 31, 2002, that Duke's authorized return in 2002 was 12.50%, and that Duke could have written off all of the GridSouth costs in 2002 and Duke would have still earned in excess of its authorized return on common equity. In my view, this consideration strongly shows that the deferral is not justified on the grounds of materiality and it is clearly not equitable for the rates that are established in this proceeding to provide for the recovery of GridSouth costs because the rates charged in 2002 were sufficient to recover the GridSouth costs.

Third, the Majority goes to great length to explain why its decision to allow deferral of the GridSouth costs is in violation of the Clean Smokestacks Act of 2002 (the Act). However, I am not convinced by their explanation and I note that even Duke did not advance the theory adopted by the Majority to support its decision with respect to the Act. Further, I would have denied the deferral, amortization, and cost recovery approved by the Majority even if it is not in violation of the Act for the other reasons stated herein.

Finally, given the majority's decision on this issue, I am deeply concerned that the signal has now been sent to Duke that it is far better to disregard the Commission's Rules (that is, by not having sought deferral of the GridSouth costs in a timely manner), and then to later ask forgiveness for having done so, than it is to comply with such rules when doing so would most likely produce an unfavorable result from the Company's perspective. Clearly, Duke should not have deferred the GridSouth costs without first having obtained this Commission's approval, and I cannot, and do not, accept that Duke was not well aware of that fact when it decided to do so, the Clean Smokestacks Act and Duke's alleged misunderstanding of that Act notwithstanding. I would not have, and the majority should not have, condoned Duke's having disregarded the Commission's Rules. Indeed, at the very least, the majority should not have rewarded Duke for having done so, as it has elected to do in this instance.

For these reasons, I dissent with respect to the Majority's decision on the GridSouth issue, but concur with the other decisions of the Commission in this proceeding.

\s\ Robert V. Owens, Jr.
Commissioner Robert V. Owens

DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 829
DOCKET NO. E-100, SUB 112
DOCKET NO. E-7, SUB 795

COMMISSIONER LORINZO L. JOYNER, DISSENTING IN PART: I must dissent from that part of the majority's order that approves a 10-year amortization of Duke's costs to develop the proposed GridSouth RTO, which translates into a $2.9 million operating expense in Duke's cost of service in this case. I believe that the majority's decision is contrary to the Clean Smokestacks Act and to generally accepted principles of accounting and Commission

Rule R8-27. I am also of the opinion that the decision deviates from past Commission practices as to deferrals of costs, and, as such, sets a dangerous precedent.

The Clean Smokestacks Act. The majority begins by considering the impact of the Clean Smokestacks Act of 2002 (the Act). This landmark legislation was designed to address the clean-up of coal-fired electric generating plants in North Carolina. The Act requires the utilities involved to undertake significant capital costs necessary to meet the new limitations on emissions imposed in G.S. 143-215.107D. The utilities are allowed to accelerate the recovery of these costs, with 70% of the costs to be recovered through amortization during a rate freeze period. G.S. 62-133.6(b). During this rate freeze -- from June 20, 2002, through December 31, 2007 -- the utilities' base rates shall remain unchanged. G.S. 62-133.6(e). However, consistent with the public interest, the Commission may allow rate reductions if requested by the utilities, G.S. 62-133.6(e)(2), and may allow other "adjustments to base rates, or deferral of costs or revenues, due to one or more of the following conditions occurring during the rate freeze period," and four limited conditions are clearly defined, G.S. 62-133.6(e)(1).

In interpreting the Act, it is important to consider the purpose of the legislation. The legislation was passed while the electric utilities operating coal-fired generating plants in North Carolina were enjoying healthy financial returns and earnings. The intent was to effectively capture some of those returns for the very worthy public purpose of reducing emissions from those coal-fired plants. The purpose of the rate freeze was to facilitate the utilities' environmental clean-up efforts, at a time when they could afford to undertake such clean-up, by restricting rate adjustments -- up or down -- and deferrals -- of both costs and revenues -- to certain circumstances. Some of the exceptions protect the utility and some of them protect ratepayers, but only limited adjustments were allowed for the five-and-a-half-year rate freeze period, during which time the utilities must amortize most of their clean-up costs.

The majority engages in an exhausting analysis of the Act and comes up with a novel interpretation that, until today, has never been revealed. The majority declares that the Act simply does not address the circumstances presented by Duke's request to defer its GridSouth costs. The majority takes the position that "nothing in the statutory language bars the Commission from allowing a rate change after the rate freeze period resulting from costs incurred before the rate freeze period ..." I believe that the majority's analysis misses the point.

First, I believe that the rate freeze bars deferrals of costs as well as changes in base rates unless they are specifically excepted and allowed.[1] If the rate freeze was not intended to bar deferrals, there would have been no need to allow certain deferrals in the exceptions in G.S. 62-133.6(e)(1). G.S. 62-133.6(e)(1) allows "adjustments to base rates, or deferral of costs or revenues, due to one or more of the following conditions occurring during the rate freeze period." The fact that certain deferrals are spelled out and allowed by G.S. 62-133.6(e)(1) indicates that the rate freeze applies to deferrals generally and that deferrals other than those allowed are barred by the rate freeze. Duke's present request to defer its GridSouth costs does not come within any of the exceptions that are allowed, and it is barred by the rate freeze.

[1] The majority begins by stating, "By its explicit terms, the statute precludes...certain cost or revenue deferrals during a rate freeze period..." (emphasis added). Actually, the Act explicitly allows certain deferrals, and I believe that deferrals that are not allowed are precluded.

Second, I see no basis for concluding that costs incurred prior to the beginning of the rate freeze period should be treated differently. There is no explicit statutory language upon which to base a distinction between pre- and during-rate-freeze costs. The language of the statute makes very clear that the allowed exceptions must be based upon conditions occurring during the rate freeze period, but there is no language distinguishing as to costs incurred before or during the rate freeze period. The majority states repeatedly that it is applying the "literal language" of the statute, but a fundamental distinction upon which the majority relies – the distinction between pre- and during-rate-freeze costs -- is not based upon any explicit language in the statute. The majority, in effect, writes into G.S. 62-133.6(e) a broad exception for "deferrals of costs that were incurred prior to the beginning of the rate freeze." No such exception was written into the Act by the General Assembly, and not even Duke believes that there is such an exception in the Act.

The distinction relied upon by the majority also fails to effectuate the purpose of the Act. The majority correctly states the purpose of the rate freeze -- "to require the affected utilities to address all costs incurred during the rate freeze period using revenues derived from existing rates" -- but a deferral of pre-rate-freeze costs and later inclusion of them in post-rate-freeze rates would effectively erode the purpose of the rate freeze and the intent of the Act just as surely as a deferral of during-rate-freeze costs.

The majority's decision, in essence, is "the Act does not address Duke's GridSouth request, Duke could and should have applied for a deferral of the GridSouth related expenditures in June 2002, but that is not a problem." Although it concludes that Duke's request is late, the majority immediately forgives the delay and creates a regulatory asset nunc pro tunc as of June 2002. This forgiveness is no small matter. First, it establishes a retroactive deferral of costs extending back into the rate freeze period, which I believe violates G.S. 62-133.6(e). Second, it completely excuses non-compliance with the majority's own interpretation of the Act (and non-compliance with Commission Rule R8-27) and thereby sets up the operating expense in the test period used in this case. The majority excuses Duke because it "would have been difficult for Duke to know ... the time had come to request deferral and amortization" in June 2002. In my opinion, this rationale does not withstand scrutiny. Both generally accepted accounting principles and Commission Rule R8-27 made clear that some new accounting treatment was required as soon as GridSouth was terminated, as discussed below.

The essence of Duke's argument, on the other hand, is "the rate freeze and its exceptions did not allow this deferral request, and this rate case is therefore our first opportunity to present it." Duke's premise is correct, but I believe that its conclusion is wrong. The fact that the rate freeze barred this request does not mean that Duke can simply wait it out. The fact that the rate freeze barred this deferral means that Duke cannot present this claim -- not during the rate freeze and not now. Allowing Duke to defer GridSouth costs that were incurred over five years ago, before the rate freeze, and to now include them in fixing rates for 2008, after the rate freeze, compromises the purpose of the rate freeze and fundamentally changes the equities embodied in the Clean Smokestacks legislation. I do not believe that the General Assembly ever intended such a result.

In short, I believe that the majority's decision violates both the language and the purpose of the Clean Smokestacks legislation. The majority parses the language of the Act and asserts that it does not specifically address the present fact situation, that there is effectively a "hole" in the Act that allows this deferral to pass. While I understand the imperative of finding one, I do not believe that there is any hole in the Act or any uncertainty in its language. If the present situation is not more expressly prohibited by the language of the Act, it is only because no one ever imagined that the Commission would countenance such extraordinary accounting as hoarding an old deferral claim until after the freeze period had expired, which brings me to my next point.

Accounting Principles and Commission Rule. Even if I could accept the majority's conclusion that the Clean Smokestacks Act does not bar deferral of the GridSouth costs, Duke's request is contrary to generally accepted principles of accounting and Commission Rule R8-27, and it should be denied on that alternative ground.

Duke should not be allowed to simply retain its GridSouth costs on its books for years without either writing them off as a loss or converting them into a regulatory asset by an accounting order from the Commission. Since no accounting order was requested, no proper GridSouth regulatory asset was ever created for North Carolina retail ratemaking purposes, and the related operating expense during the test period should be removed from the cost of service in this case.

The majority says that its decision "is fully consistent with ... ordinary ratemaking principles." I do not agree. This decision is not consistent with the accounting principles and Rule discussed below, and it is anything but ordinary ratemaking. To provide context, consider a more typical deferral scenario. Suppose that a hurricane requiring extensive rebuilding strikes in Year 1. Suppose further that the utility is experiencing an unusually high return in Year 1 and fears that the Commission might not approve a deferral of the storm damage costs if presented right away. Would the utility be allowed to simply hold its deferral claim until its return drops and then present the claim years later, say in Year 5, when circumstances are more favorable for approval? Certainly not, yet I believe that the foregoing scenario is analogous to the majority's handling of Duke's GridSouth costs. Circumstances were not favorable for approval in 2002 and Duke did not present its deferral request then, but the majority has allowed Duke to sit on its claim until more favorable circumstances come along. A claim for deferral of costs, once ripe for decision, is not a chip to be held until needed and cashed at the convenience of the utility.

Duke places great reliance upon the January 25, 2001 Declaratory Order issued by FERC, but that reliance is misplaced. As I understand the Declaratory Order, FERC allowed the GridSouth participants to treat their ongoing investments in the project as deferred debits and to accumulate carrying costs, but, because GridSouth did not yet exist and the participating utilities could not record a receivable from a non-existing entity, the Declaratory Order required the participants to record the amount in Account 186 – Miscellaneous Deferred Debits. It was anticipated that once GridSouth was formed, GridSouth would record a payable to each utility and each utility's costs would become a receivable from GridSouth. The Declaratory Order did not pre-approve any rate recovery; it explicitly provided that "petitioners did not request pre-approval for rate recovery and we are not granting it here." FERC could not have authorized a deferral of costs for retail ratemaking purposes, even if it had desired to do so, since this Commission retains exclusive jurisdiction as to retail ratemaking. Events did not unfold as anticipated by FERC, and the GridSouth project was terminated in June 2002. Once the project was terminated, the underlying rationale of the Declaratory Order was no longer valid. The Order had only approved use of Account 186 as a temporary measure until GridSouth was formed. Once it became clear that GridSouth would not be formed, it was no longer appropriate for Duke to maintain its costs in Account 186 and whatever authority the Declaratory Order might have provided to Duke beforehand vanished at that time.

At that time, re-examination of the proper accounting of the GridSouth costs was required. The GridSouth costs were expenses that could have been charged to net income at the time of the GridSouth termination and written off as a loss. The alternative (again assuming no bar in the Clean Smokestacks Act) was creation of a regulatory asset to be recorded in Account 182.3 – Other Regulatory Assets.[1] Under generally accepted accounting principles, nonregulated companies are not allowed to defer spent costs; they must write them off in the fiscal year in which the costs or the loss was incurred. Regulated companies such as Duke are sometimes allowed to defer spent costs from the fiscal year in which they are incurred to later years, provided certain conditions are met. See Financial Accounting Standards Board's Statement of Financial Accounting Standards (SFAS) No. 71[2] and Commission Rule R8-27. Costs deferred under SFAS No. 71 are typically referred to as a "regulatory asset." They are not assets in the traditional sense, but they have economic value because of their treatment in the regulatory process. One very significant value is that the amortized expense is kept on the utility's books for an extended period of time, effectively reserving the costs for potential inclusion in rates.

To justify treating the GridSouth costs as a regulatory asset, Duke needed an accounting order from this Commission. Neither the out-dated FERC Declaratory Order nor the regulatory decisions of other jurisdictions can appropriately be regarded as a surrogate. Both accounting principles and Commission Rule R8-27 made clear that an order from this Commission was necessary.

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[1] The description for Account 182.3 – Other Regulatory Assets in the FERC Uniform System of Accounts reads in relevant part as follows:

> 182.3 Other regulatory assets.
>
> ....
>
> B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts <u>but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services.</u> ... (Emphasis added.)

[2] SFAS No. 71, in pertinent part, provides as follows:

> An enterprise shall capitalize all or part of an incurred cost [footnote omitted] that would otherwise be charged to expense if both of the following criteria are met:
>
> a. It is probable [footnote omitted] that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.
>
> b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

ELECTRIC – FILINGS DUE PER ORDER OR RULE

Commission Rule R8-27(a)(2) specifically requires that "electric utilities under the jurisdiction of the Commission must apply to the Commission for any North Carolina retail jurisdictional use of...Account 182.3 – Other Regulatory Assets." Despite its being cited and relied upon by the Public Staff, the majority never addresses Commission Rule R8-27. The majority says that "it would have been preferable for Duke to have signaled to the Commission at an earlier time that it intended to seek a deferral...." In the face of a Commission Rule requiring that the utility must apply for Commission authority to set up a regulatory asset, the most the majority is willing to say is that it would have been preferable for Duke to have signaled the Commission as to what it intended to do. I find this a troublesome stance for the Commission to take vis-à-vis the public utilities it is charged with regulating.

In summary, Duke should have either written off the North Carolina retail portion of its GridSouth costs as a loss or requested Commission approval to defer the amount as a regulatory asset in or about June 2002. Duke did neither; instead, Duke unilaterally elected to carry spent costs on its books for years, contrary to accounting principles and the Commission's Rule. Sanctioning such conduct is, in my opinion, an unwise departure from well-established practices and a bad precedent for the future.

Commission Precedents. Even if I could get past my previous two objections, there is the issue of the Commission's past practices with respect to deferrals of costs. The majority claims that it has evaluated Duke's request under the usual principles applicable to such requests, but I disagree. I believe that the majority's decision represents a significant and unprecedented indulgence in the exercise of the Commission's discretion.

Although generally disfavored, deferral accounting has been authorized in special instances for costs that are unusual and material and of such magnitude that departure from traditional accounting practices is deemed warranted from the standpoint of fairness and equity to both consumers and shareholders.[1] See Order Approving Deferred Accounting Treatment issued April 29, 1997, in Docket G-5, Sub 369. Over time, the Commission has considered many requests for deferrals of costs, and, despite the variety and range of the requests, examination reveals fairly consistent practices. The majority's present decision goes further: while it articulates the correct standard, it is more lenient than these precedents in significant ways.

First, in the past, the Commission has ordered that amortization begin as of the time the costs or the loss was first incurred (here, that was upon termination of GridSouth in June 2002) and the Commission has generally allowed amortization periods of 5 years or less.[2] Here, the majority has ordered a 10-year amortization. Duke did not request such; Duke requested a 5-year

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[1] Deferral accounting has been allowed for such costs as rebuilding after a hurricane or severe ice storm (Hurricane Hugo in Docket No. E-7, Sub 460; Hurricane Ivan in Docket No. E-7, Sub 776; Hurricane Isabel and the 2003 ice storms in Docket No. E-2, Sub 843; Hurricane Fran in Docket No. E-2, Sub 699), major clean-up costs (manufactured gas plants and transformer sites in Docket No. E-2, Sub 894), and the Year 2000 computer conversion (Docket No. G-5, Sub 369). See also the Commission's discussions of abandoned plants (e.g., in Docket No. E-2, Subs 537 and 333).

[2] For example, the Commission approved amortization periods of 5 years in Docket No. E-2, Sub 843, in Docket No. E-7, Sub 460, and in Docket No. E-7, Sub 776; 40 months in Docket No. E-2, Sub 699; and 3 years in Docket No. G-5, Sub 369. Longer periods have been allowed for major plant abandonments.

amortization. The majority, on its own initiative, has authorized a period longer than requested, and the effect of its doing so is significant. Approving a 10-year amortization period reduces the operating expense in the test period, but it extends the period of amortization well into the future and thereby creates a test period expense that would otherwise have been hard to sustain. A 5-year amortization beginning in June 2002 would have expired in 2007. There would have been a year's expense in the 2006 test period used in this case, but the amortization would have been almost over at that point, and the test period expense would have been hard to justify from a ratemaking perspective. As a matter of ratemaking, an expiring test period expense representing a unique situation such as GridSouth would have surely been challenged by a normalization adjustment since it would not have represented any ongoing expense.

Second, in the past, the Commission has considered the utility's earnings as an important factor in exercising the Commission's discretion. Costs must be "unusual and material" for a deferral to be considered, and their impact on earnings goes to establishing whether the costs are "material." The Commission has stated that "in considering whether the public interest would be served by the significant departure from fundamental ratemaking principles that would result ... it is appropriate, among other things, to consider [the utility's] level of earnings and the effect that deferring, or not deferring, certain storm costs would have on those earnings." Order Granting in Part and Denying in Part Request for Deferral Accounting issued December 23, 2003, in Docket No. E-2, Sub 843.

Here, consideration of Duke's earnings works against a deferral,[1] and so the majority dismisses this consideration by stating, without precedent, that a healthy return "alone does not preclude allowance of the deferral request given the unusual nature of the costs at issue here." Apparently, the majority now believes, contrary to the Commission's previous pronouncements, that if the costs are unusual enough, they need not be material at all compared to earnings. At another point, the majority states that Duke's earning do not constitute a bar "given the magnitude of the costs in question and the reasonableness and prudence of the decisions that led to their incurrence...." Again, in its determination to reach a specific result, the majority has introduced a new standard different from that it traditionally applies.

Finally, the majority says that, as a response to Duke's healthy financial earnings, it has lengthened the amortization period to 10 years. The majority may regard this extension as a sufficient counterbalance, but in fact, as discussed above, the 10-year amortization actually works to Duke's favor by, in effect, "normalizing" a unique test period expense that would have otherwise been about to expire and hard to justify as a matter of ratemaking.

<u>Conclusion.</u> There is an implicit assumption throughout the majority's decision that equity favors Duke. I understand the source of this assumption and am not unsympathetic: GridSouth was a response to FERC mandates, despite widely-held concerns that FERC's policies did not favor the utilities and ratepayers in the Southeast. There are, however, other relevant considerations, and for me the most important consideration of all is the equities embodied in the Clean Smokestacks Act.

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[1] In my opinion, if Duke had requested a deferral order in June 2002, that request would likely have been denied by the Commission on the basis that the Company's earnings were healthy enough to justify charging the GridSouth costs to net income at that time.

The Clean Smokestacks Act was the product of a grand but delicate compromise on the part of numerous stakeholders – the electric utilities, consumer interests, and the environmental community. To the extent the Commission approves a retroactive deferral of costs that was not intended by the parties who negotiated that compromise (and it was clearly not intended by the Public Staff and the Attorney General), the Commission allows Duke to re-write this historic compromise more than five years after the fact. We will never know for sure, but I cannot help but wonder if Duke is just as surprised as anyone by the majority's decision.

\s\ Lorinzo L. Joyner
Commissioner Lorinzo L. Joyner

DOCKET NO. E-7, SUB 828
DOCKET NO. E-7, SUB 829
DOCKET NO. E-100, SUB 112
DOCKET NO. E-7, SUB 795

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 828 In the Matter of Duke Energy Carolinas, LLC – Investigation of Existing Rates and Charges Pursuant to Regulatory Condition No. 76 as Contained in the Regulatory Conditions Approved by Order Issued March 24, 2006, in Docket No. E-7, Sub 795 DOCKET NO. E-7, SUB 829 In the Matter of Duke Energy Carolinas, LLC – Investigation of Environmental Compliance Costs Pursuant to G.S. 62-133.6(d) and (f) DOCKET NO. E-100, SUB 112 In the Matter of Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 158 Entitled "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" and DOCKET NO. E-7, SUB 795 In the Matter of Application of Duke Energy Corporation for Authorization under G.S. 62-111 to Enter Into a Business Combination Transaction With Cinergy Corp. and for Approval of Affiliate Agreements under G.S. 62-153	ERRATA ORDER

ELECTRIC – FILINGS DUE PER ORDER OR RULE

BY THE PRESIDING COMMISSIONER: On December 20, 2007, the Commission issued its Order Approving Stipulation and Deciding Non-Settled Issues in the above dockets. A post-issuance review of said Order revealed that the Commission erroneously instructed Duke Energy Carolinas, LLC to implement a "12-month uniform rate increment rider" to produce a fair sharing of the benefits of the estimated merger savings between ratepayers and shareholders. (Emphasis added.)

The Presiding Commissioner finds good cause to issue an Errata Order deleting the word "uniform" on Page 36, the second full paragraph, the fifth line; deleting the word "uniform" on Page 37, the second line; and deleting Footnote No. 16 on Page 36 in its entirety.

IT IS, THEREFORE, SO ORDERED.
ISSUED BY ORDER OF THE COMMISSION.

This the 21st day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

kh122107.01

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

DOCKET NO. E-7, SUB 825

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Carolinas, LLC Pursuant to	)	ORDER APPROVING
G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel	)	FUEL CHARGE
Charge Adjustments For Electric Utilities	)	ADJUSTMENT

HEARD: Tuesday, May 1, 2007, at 10:00 a.m. in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Commissioners Robert V. Owens, Jr., and William T. Culpepper, III

APPEARANCES:

For Duke Energy Carolinas, LLC:

Lara Simmons Nichols, Associate General Counsel, Duke Energy Corporation, Post Office Box 1244, Charlotte, North Carolina 28201-1244

and

Robert W. Kaylor, Law Office of Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 160, Raleigh, North Carolina 27603

For the Using and Consuming Public:

James D. Little, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Len Green, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For the Carolina Utility Customers Association, Inc.:

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

For the Carolina Industrial Group for Fair Utility Rates III:

Carson Carmichael, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27602

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

BY THE COMMISSION: On March 2, 2007, Duke Energy Carolinas, LLC ("Duke Energy Carolinas" or the "Company"), filed an Application and accompanying testimony and exhibits pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel charge adjustments for electric utilities.

On March 15, 2007, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice.

On March 7, 2007, the Carolina Utility Customers Association, Inc. ("CUCA") filed a petition to intervene. On March 13, 2007, Carolina Industrial Groups for Fair Utility Rates III ("CIGFUR III") filed a petition to intervene. The Commission allowed the interventions of CUCA and CIGFUR by Order dated March 15, 2007. On April 12, 2007, Roy Cooper, Attorney General, filed a Notice of Intervention. The intervention of the Attorney General is recognized pursuant to G.S. 62-20. The intervention of the Public Staff is recognized pursuant to Commission Rule R1-19(e).

On March 29, 2007, Duke Energy Carolinas filed a motion for leave to submit the testimony of John J. Roebel and the Commission granted this motion by Order dated April 5, 2007. On April 18, 2007, Duke Energy Carolinas filed the supplemental testimony of Jane L. McManeus. On that same date, the Public Staff filed a notice of affidavits and the affidavits of Thomas S. Lam, Sonja Johnson, and Darlene P. Peedin. On April 30, 2007, CUCA gave notice that it wished to cross-examine the Public Staff witnesses pursuant to G.S. 62-68.

On April 30, 2007, Duke Energy Carolinas filed affidavits of publication indicating that public notice had been provided in accordance with the Commission's procedural order.

The case came on for hearing as ordered on May 1, 2007. M. Elliott Batson, Director, Coal Procurement; John J. Roebel, Senior Vice President, Engineering and Technical Services; Jane L. McManeus, Director, Rates; Dhiaa M. Jamil, Senior Vice President, Nuclear Support; and David C. Culp, Manager, Nuclear Fuel Management presented direct testimony for the Company. Darlene P. Peedin, Staff Accountant, Accounting Division presented direct testimony on behalf of the Public Staff. The Commission admitted into evidence the affidavits of Thomas S. Lam, Utilities Engineer, Electric Division, and Sonja R. Johnson, Staff Accountant, Accounting Division, following CUCA's waiver of its right to cross-examine them. No other party presented witnesses and no public witnesses appeared at the hearing.

After the hearing, the parties filed briefs and proposed orders on June 6, 2007, as allowed by the Commission.

Based upon the Company's verified Application, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. Duke Energy Carolinas is a duly organized limited liability company existing under the laws of the State of North Carolina and is engaged in the business of developing,

generating, transmitting, distributing, and selling electric power to the public in North Carolina, and is subject to the jurisdiction of the North Carolina Utilities Commission as a public utility. Duke Energy Carolinas is lawfully before this Commission based upon its application filed pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the 12-month period ended December 31, 2006.

3. Duke Energy Carolinas' fuel procurement and power purchasing practices during the test period were reasonable and prudent.

4. The test period per book system sales are 78,048,965 MWh.

5. The test period per book system generation is 87,708,561 MWh and is categorized as follows:

Generation Type	MWh
Coal	44,722,221
Oil and Gas	263,064
Light Off	-
Nuclear	40,422,697
Hydro	1,229,866
Net Pumped Storage	(807,553)
Purchased Power	2,059,398
Catawba Interconnection Agreements	(344,397)
Interchange	163,265
Total Generation	87,708,561

6. The nuclear capacity factor appropriate for use in this proceeding is 89%.

7. The adjusted test period system sales for use in this proceeding are 78,346,601 MWh.

8. The adjusted test period system generation for use in this proceeding is 88,036,727 MWh and is categorized as follows:

Generation Type	MWh
Coal	45,852,504
Oil and Gas	222,925
Light Off	-
Nuclear	39,139,876
Hydro	1,617,800
Net Pumped Storage	(801,575)
Purchased Power	2,005,197
Total Generation	88,036,727

9. The appropriate fuel prices and fuel expenses for use in this proceeding are as follows:

A. The coal fuel price is \$25.38/MWh.
B. The oil and gas fuel price is \$142.56/MWh.
C. The light off fuel expense is \$12,684,000.
D. The total nuclear fuel price is \$4.58/MWh.
E. The nuclear fuel price for Catawba generation is \$4.62/MWh.
F. The purchased power fuel price is \$26.58/MWh.
G. The adjusted level of fuel credits associated with intersystem sales is \$123,692,000.

10. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 58% of the energy portion of the purchase price is reasonable in this proceeding for purposes of determining the Company's Experience Modification Factor (EMF).

11. The adjusted test period system fuel expense for use in this proceeding is \$1,317,195,000.

12. The appropriate fuel factor for purposes of this proceeding is 1.6812¢/kWh, excluding gross receipts tax.

13. The Company's North Carolina test period jurisdictional fuel expense under-collection was \$56,203,000. The pro forma North Carolina jurisdictional sales are 54,172,678 MWh.

14. The Company's Experience Modification Factor ("EMF") is an increment of 0.1037¢/kWh, excluding gross receipts tax.

15. The final net fuel factor to be billed to Duke Energy Carolinas' North Carolina retail customers during the 2007-2008 fuel adjustment billing period is 1.7849¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.6812¢/kWh and the EMF increment of 0.1037¢/kWh.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural, and jurisdictional in nature and is not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for a historical 12-month test period. In Commission Rule R8-55(b), the Commission has prescribed the 12 months ending December 31st as the test period for Duke Energy Carolinas. The Company's filing was based on the 12 months ended December 31, 2006.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

Commission Rule R8-52(b) requires each electric utility to file a Fuel Procurement Practices Report at least once every 10 years and each time the utility's fuel procurement practices change. The Company's updated fuel procurement practices were filed with the Commission in Docket No. E-100, Sub 47A, in July 2004 and were in effect throughout the 12 months ending December 31, 2006. In addition, the Company files monthly reports of its fuel costs pursuant to Commission Rule R8-52(a). Further evidence for this finding of fact is found in the testimony of Company witnesses Batson and Culp.

Duke Energy Carolinas witness Batson described the Company's fossil fuel procurement practices. These practices include estimating fuel requirements, establishing appropriate inventory requirements, monitoring on-going fuel requirements, developing qualified supplier lists, bid evaluation, balancing long term contracts and spot purchases, expediting/monitoring purchases, and on-going quality control.

Further, witness Batson testified that Duke Energy Carolinas continues to take action to implement and improve a comprehensive coal procurement strategy that reduces the risk of extreme volatility in average coal costs. Aspects of this strategy include having the appropriate mix of contract and spot purchases, staggering contract expirations such that the Company is not faced with price changes for a significant percentage of purchases at any one time, pursuing contract extension options that provide flexibility to extend terms within some price collar, and developing a diverse coal supply portfolio from different coal supply regions as they become feasible and economical. Witness Batson testified that the Company is continuing its efforts to develop the ability to burn non-Central Appalachia and non-traditional Central Appalachia coal, primarily through coal blending at certain of its facilities in order to take advantage of market opportunities to reduce coal costs as they come about. He stated that Duke Energy Carolinas typically issues two Requests for Proposal ("RFP") addressing term purchases each year and plans to issue future RFPs that address coal supply from throughout the United States and international sources. Witness Batson testified that the Company will be continuing to evaluate operational plant issues associated with non-Central Appalachia and non-traditional Central Appalachia coal as well as working closely with the appropriate railroads to develop the needed infrastructure to deliver those types of coal. This approach will analyze current and future opportunities and provide on-going flexibility to take advantage of different purchase opportunities in changing domestic and international market conditions.

Company witness Culp testified as to Duke Energy Carolinas' nuclear fuel procurement practices. These practices involve computing near and long-term consumption forecasts, establishing target inventory levels, qualifying suppliers, requesting proposals, negotiating a portfolio of supply contracts, assessing spot market opportunities, and monitoring deliveries for each of the components of nuclear fuel production cycle: mining uranium, conversion, enrichment, and fabrication.

Further, witness Culp testified that Duke Energy Carolinas relies extensively on long term contracts to cover the largest portion of its forward requirements in the four industrial stages of the nuclear fuel cycle. By staggering long term contracts over time, the Company's purchases within a given year consist of a blend of contract prices negotiated at many different periods, which has the effect of smoothing out the Company's exposure to price volatility. Witness Culp noted that this strategy depends on the willingness of fuel suppliers to offer certain pricing mechanisms under long term contracts, such as fixed prices, base escalated prices, or caps on market index prices. He also testified to the recent rise in uranium spot market prices, and explained that, as a result of this increase, the Company is finding that uranium suppliers are reluctant to offer these pricing mechanisms. Instead, suppliers are offering contracts with delivery prices tied to future market prices with no ceiling and a floor price equal to current market prices. Witness Culp testified that, as a result of this shift, the Company is now buying uranium in the spot market and holding it to meet future requirements.

No party presented or elicited testimony contesting the Company's fuel procurement and power purchasing practices. Based upon the fuel procurement practices report, the evidence in the record, and the absence of any evidence to the contrary, the Commission concludes that these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-6

The evidence for these findings of fact is found in the testimony of Company witnesses McManeus, Roebel, and Jamil and the affidavit of Public Staff witness Lam.

Company witness McManeus testified that the test period per book system sales were 78,048,965 MWh and that the test period per book system generation was 87,708,561 MWh. The test period per book generation is categorized as follows:

Generation Type	MWh
Coal	44,722,221
Oil and Gas	263,064
Light Off	-
Nuclear	40,422,697
Hydro	1,229,866
Net Pumped Storage	(807,553)
Purchased Power	2,059,398
Catawba Interconnection Agreements	(344,397)
Interchange	163,265
Total Generation	87,708,561

Company witnesses Roebel and Jamil testified as to the operation and performance during the test period of the Company's (1) fossil-fueled and hydroelectric generating facilities and (2) nuclear generation facilities, respectively. Witness Roebel testified that Duke Energy Carolinas operates a diverse mix of units that allow the Company to meet continuously changing customer load patterns in a logical and cost-effective manner. He testified that, during the test year, the fossil-fueled generating plants provided approximately 52% of the Company's total generation and that the heat rate of its coal units was 9,602 BTU/kWh. Achievement of this heat rate continues Duke Energy Carolinas' consistent track record of operating the most efficient fossil-fired units in the country. Witness Roebel further testified as to the various performance indicators that are indicative of solid performance and good operation and management of Duke

Energy Carolinas' fossil and hydroelectric fleet during the test period, particularly in light of the number of scheduled outage days required for equipment replacements and environmental control installations.

Commission Rule R8-55(c)(1) provides that capacity factors for nuclear production facilities will be normalized based generally on the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council's ("NERC") Equipment Availability Report, adjusted to reflect the unique, inherent characteristics of the utility facilities, and any unusual events. Witness Jamil testified that the test period included five refueling outages and that during this period Duke Energy Carolinas achieved a system average nuclear capacity factor of 90.08%. He testified that the most recent (2001-2005) NERC five-year average nuclear capacity factor for pressurized water reactor units is 89.21%. The affidavit of Public Staff witness Lam also included this information.

Witness Jamil recommended a nuclear capacity factor of 89% for use in setting the fuel rate in this proceeding, based on the operational history of the Company's nuclear units and the number of outage days scheduled for the billing period. Witness Jamil testified that the Nuclear Regulatory Commission ("NRC") renewed the licenses for the Company's three nuclear stations for an additional 20 years each. He explained that, in order to meet NRC regulatory requirements and to perform projects necessary for continued operation of the nuclear fleet, Duke Energy Carolinas must schedule additional outage days during upcoming refueling outages. Witness Jamil testified that execution of these projects will have a minor impact on the nuclear fleet's capacity and availability over the short term; however, performance of these projects is necessary to continue providing customers with the benefits from the Company's diverse generation mix and the low production costs, including fuel costs, associated with its nuclear units.

By recommending Commission approval of Duke Energy Carolinas' proposed fuel factor, Public Staff witness Lam implicitly agreed with the Company's per books sales and generation levels of 78,048,965 MWh and 87,708,561 MWh, respectively, as well as the Company's recommended nuclear capacity factor of 89%. No other party contested these amounts.

Based upon the agreement of the Company and the Public Staff as to the appropriate levels of per book system MWh generation and sales, and noting the absence of evidence to the contrary, the Commission concludes that the levels of per book system sales of 78,048,965 MWh and per book system generation of 87,708,561 MWh are reasonable and appropriate for use in this proceeding.

Based upon the requirements of Commission Rule R8-55(c)(1), the historical and reasonably expected performance of the Duke Energy Carolinas system, and the agreement of the Public Staff, the Commission concludes that the 89% nuclear capacity factor and its associated generation of 39,139,876 MWh, excluding the Catawba Joint Owners' portion of said generation, are reasonable and appropriate for purposes of determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 7-8

The evidence for these findings of fact is found in the testimony of Company witness McManeus.

Ms. McManeus made adjustments of 297,636 MWh and 328,166 MWh to per book system sales and generation, respectively, for adjustments relating to normalization for weather, customer growth, the Catawba Interconnection Agreements and line losses/Company use, based on an 89% normalized system nuclear capacity factor. She thus calculated an adjusted system sales level of 78,346,601 MWh and an adjusted system generation level of 88,036,727 MWh.

By recommending Commission approval of Duke Energy Carolinas' proposed fuel factor, Public Staff witness Lam implicitly accepted witness McManeus' adjusted sales and generation levels of 78,346,601 MWh and 88,036,727 MWh, respectively. No party contested the Company's adjustments for weather normalization, customer growth, Catawba retained generation, or line losses/Company use.

The Commission concludes, after having found a system nuclear capacity factor of 89% to be reasonable and appropriate in Finding of Fact No. 6, that the adjustment to per book system generation of 328,166 MWh and the resulting adjusted test period system generation level of 88,036,727 MWh are both reasonable and appropriate for use in this proceeding. Total adjusted generation is categorized as follows:

Generation Type	MWh
Coal	45,852,504
Oil and Gas	222,925
Light Off	-
Nuclear	39,139,876
Hydro	1,617,800
Net Pumped Storage	(801,575)
Purchased Power	2,005,197
Total Generation	88,036,727

The Commission also finds the adjusted sales level of 78,346,601 MWh to be reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is found in the testimony and exhibits of Company witnesses Batson, Roebel, McManeus, Jamil, and Culp.

Company witness Batson testified regarding Duke Energy Carolinas' fossil fuel costs during the test year and the changes in those costs expected in 2007 and 2008. Witness Batson testified that the Company's delivered cost of coal during the test period rose due to increasing mine and transportation costs for coal and that these prices were consistent with the projections used by the Company in developing the fuel factor billed during the July 2006 through June 2007 period. He noted that the market price for coal has significantly increased since the early 2000s due to increasing domestic and international demand for coal, limited production response to this increased demand (especially in Central Appalachia), continuing strong export market conditions for Central Appalachia coal, increasing mining operating costs, high natural gas prices, and transportation complexities associated with alternative coal sources. He explained that, because Duke Energy Carolinas purchased a large percentage of its coal supply under multi-year term contract arrangements negotiated prior to these coal market increases, the Company benefited over the last two to three years from lower priced, longer term contracts, resulting in significantly lower average coal mine costs in 2003 through 2006 compared to prevailing market prices. Witness Batson further testified that, as the Company's older, existing coal contracts expire, they are replaced at higher prevailing market prices.

Witness Batson testified that the February, 2007 market prices for Central Appalachia coal to be delivered in 2007 and 2008 are significantly lower than prices over the last few years. The primary reasons for declining prices are (1) a reduction in demand for coal in 2006 and early 2007 primarily due to mild weather, (2) flat Central Appalachia coal production in 2006 compared to 2005 after several years of declining production, and (3) improving utility coal inventories throughout the United States. He stated that these changes provide increased leverage for buyers compared to previous years, but that it is still too soon to determine if these changes represent longer term fundamental changes to the market since coal suppliers are currently unwilling to offer contract terms longer than one to two years at these prices. Witness Batson further testified that the longer term market drivers for coal supplies that led to the increase in prices over the last several years appear strong and are likely to cause upward pressure on prices over the long term.

Witness Batson testified that the coal cost used by the Company in calculating its proposed fuel factor is based on the prices for existing coal purchase commitments and the current projected market prices for coal requirements in 2007 and 2008 that have not yet been purchased. Based upon this data, witness Batson projected that the Company's average cost of coal will stabilize in the mid $40s per ton for the July, 2007 through June, 2008 billing period. This average cost of coal projected for the billing period is consistent with the projected market price for Central Appalachia coal.

Witness Batson testified that average transportation costs increased in the test year due to increases in fuel surcharges applied by the railroads as a result of increasing fuel oil prices and tariff and contractual escalations for freight rates paid in 2006. For the test year, transportation costs constituted 30% of the Company's total delivered cost of coal. Witness Batson testified that the Company expects that fuel surcharges could be volatile given that they are tied to oil prices.

Further, witness Batson testified that Duke Energy Carolinas acquired 1,260 private rail cars to be used on the CSX Transportation ("CSX") system starting in late 2006 and early 2007. He stated that these private rail cars are leased under long term arrangements and that lease costs are off-set through a reduction in base transportation rates contained in the Company's existing rail agreement with CSX. Witness Batson testified that use of private rail cars provides Duke Energy Carolinas with enhanced rail delivery performance, more efficient rail car utilization, and an improved ability to source coal from more distant basins, such as from the Northern

Appalachia coal region. In response to questions from counsel for CUCA, witness Batson explained that Appalachian Rail Services provides certain services with respect to the leased rail cars that were previously performed by CSX. Witness Batson confirmed that labor associated with unloading the trains continues to be performed by Duke Energy Carolinas and that these expenses are not included in the calculation of fuel costs recovered through the fuel clause.

In its brief, CUCA states that G.S. 105-164.14(a2) allows electric utilities to obtain a refund of a portion of the sales tax collected on the purchase or lease of railway cars. CUCA noted that, during cross-examination, a Duke witness testified that he was unaware of such a sales tax credit. However, this witness agreed, on a hypothetical basis, that if a tax had flowed through the fuel clause and Duke received a refund, Duke would appropriately apply the credit back through the fuel charge. Therefore, CUCA requests that the Commission order Duke: (i) to certify whether it has applied for any sales tax refund associated with its leased railway cars and, if not, to identify the reason(s) for the failure to so apply; (ii) to identify the dollar amount of the sales tax refund associated with leased railway cars received to date; and (iii) to credit all such refunds received to date against Duke's fuel costs in this proceeding. The Commission concludes there is insufficient evidence in the record in this proceeding to address this issue. At this point, nothing in the record suggests that Duke Energy Carolinas failed to claim any available fuel-related sales tax refund; in the absence of any evidence tending to show that such refunds were available and unclaimed and that the amount of any such refunds would have any effect on Duke Energy Carolinas' fuel factor or EMF, the Commission declines to take further action at this time. State ex rel. Utilities Commission v. Intervenor Residents, 305 N.C. 62, 286 S.E. 2d 770 (1981). Should this issue arise in a future fuel charge adjustment proceeding, the Commission will address this issue based on the evidence in the record in that proceeding.

Witness Batson further testified that the effectiveness of Duke Energy Carolinas' comprehensive coal procurement strategy has been demonstrated over the last several years by limiting average annual coal price increases and maintaining average coal costs at or well below those seen in the marketplace. He stated that Duke Energy Carolinas has also demonstrated the ability to diversify a portion of its coal supply portfolio as economics warrant. Witness Batson testified that in 2006 approximately 25% of Duke Energy Carolinas' coal purchases were non-Central Appalachia coal and non-traditional Central Appalachia coal. He stated that the Company uses a market, operational and capital cost approach to evaluate the use of these non-Central Appalachia and non-traditional Central Appalachia coals on a total cost basis.

Witness Roebel testified that the flue gas desulfurization equipment – "scrubber" – installed at the Marshall Steam Station became operational in December 2006. Witness Batson testified that the Company contracted for high sulfur Northern Appalachia coal for delivery in 2006 and 2007 to be blended and consumed at Marshall. Additional volumes of higher sulfur coal will be evaluated as future scrubbers become operational at other plants across the Carolinas. Witness Roebel stated that the Company has experienced the operational conditions, such as slagging, that it anticipated with burning coals that differ from those the plants were designed to utilize. He noted that the Company must be mindful of both immediate and long-term operational effects resulting from the use of non-Central Appalachia and non-traditional Central Appalachia coals.

Company witness Culp testified regarding Duke Energy Carolinas' nuclear fuel costs during the test year and changes expected in 2007 and 2008. Witness Culp stated that spot market prices for uranium concentrates have increased nearly tenfold since market lows occurred in calendar year 2000; however, the impact of these increases on the Company during the test period was mitigated by contracts negotiated at lower market prices prior to the test period. Witness Culp noted that industry consultants expect spot market prices to continue to rise in the near term as exploration, mine construction, and production gear up. Witness Culp further testified that spot market prices for enrichment have increased approximately seventy percent since market lows experienced in calendar year 2000. He stated that one hundred percent of the Company's enrichment purchases during the test period were delivered under long term contracts negotiated prior to the test period. As such, the unit cost of enrichment purchased by Duke Energy Carolinas in the test period was comparable to that purchased in the prior reporting period. Witness Culp testified that, as existing contracts for these components of nuclear fuel expire, they will be replaced at higher market prices.

Witness Culp testified that Duke Energy Carolinas does not anticipate a significant increase in nuclear fuel expense through the next billing cycle period. Because fuel is typically expensed over two to three operating cycles – roughly three to five years - Duke Energy Carolinas' nuclear fuel expense in the upcoming billing period will be determined by the cost of fuel assemblies loaded into the reactors during the test period as well as prior periods. He stated that the costs of the fuel residing in the reactors during the test period will be predominantly based on contracts negotiated prior to the recent market price increases. As fuel with a low cost basis is discharged from the reactor and lower priced legacy contracts expire, nuclear fuel expense is expected to increase in the future.

In response to questions from counsel for CUCA, witness McManeus testified that Duke Energy Carolinas received a $56 million payment in 2007 from the Department of Energy ("DOE") as a result of a settlement of litigation regarding the disposal of spent nuclear fuel. Witness McManeus explained that the settlement payment is to reimburse the Company for additional on-site spent nuclear fuel storage costs that the Company incurred as a result of the DOE failing to accept spent nuclear fuel for permanent disposal. She testified that these storage costs are not recovered through the fuel adjustment mechanism and that the settlement proceeds will be recorded on Duke Energy Carolinas' books using the same accounting treatment used for the storage costs. Witness McManeus further explained that the Company continues to pay the nuclear disposal fee to the DOE and that the DOE continues to have the responsibility to build a permanent waste repository. She stated that the funds the Company receives in settlement do not come out of the waste disposal funds that have been paid in by the utilities for construction of the repository; rather, the government provides separate funding for the settlement. Counsel for the Public Staff indicated that the Public Staff supports the Company's position. No party elicited evidence contradicting the Company's characterization and treatment of these settlement proceeds. The Commission concludes that Company's treatment of the DOE settlement proceeds is appropriate and that such proceeds should not be reflected as a reduction to nuclear fuel expense.

ELECTRIC – RATE SCHEDULES/RIDERS/SERVICE RULES AND REGULATIONS

Evidence concerning the reasonable and efficient operation of Duke Energy Carolinas' fossil-fueled, hydroelectric, and nuclear generating facilities is discussed above in the Evidence and Conclusions for Finding of Fact Nos. 4-6.

Witness McManeus recommended fuel prices and expenses as follows:

A. The coal fuel price is $25.38/MWh.
B. The oil and gas fuel price is $142.56/MWh.
C. The appropriate light off fuel expense is $12,684,000.
D. The total nuclear fuel price is $4.58/MWh.
E. The nuclear fuel price for Catawba generation is $4.62/MWh.
F. The purchased power fuel price is $26.58/MWh.
G. The adjusted level of fuel credits associated with intersystem sales is $123,692,000.

Public Staff witness Lam testified that he recommended that the Commission approve Duke Energy Carolinas' proposed fuel factor, and that this recommendation was based upon review of the Company's Application and coal contracts and an examination of the current coal market. By this recommendation, Public Staff witness Lam implicitly agreed with the Company's proposed fuel prices and expenses.

Based upon the evidence in the record as to the appropriate fuel prices and expenses, the Commission concludes that the fuel prices recommended by witness McManeus and accepted by the Public Staff are reasonable and appropriate for this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the affidavit and testimony of Public Staff witness Peedin and the exhibits of Company witness McManeus.

Public Staff witness Peedin stated in her affidavit that the purpose of her affidavit was to present her calculation of the appropriate fuel-to-energy percentage to be applied to the fuel costs associated with purchases from power marketers and other suppliers who supplied power to the Company during the test year. Witness Peedin indicated that, in order to determine this percentage, the Public Staff had performed an analysis of the fuel component of off-system sales made by Duke Energy Carolinas and Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc. ("PEC"), which are set forth in the utilities' Monthly Fuel Reports, for the twelve months ended December 31, 2006. She stated that, unlike in past years, the off-system sales for Virginia Electric and Power Company d/b/a Dominion North Carolina Power ("DNCP") were not utilized in the analysis because there were only two DNCP off-system sale transactions eligible for inclusion in the analysis and because these transactions did not provide meaningful data for purposes of calculating the fuel-to-energy percentage. Witness Peedin noted that one of these transactions appeared to utilize a "proxy percentage" to determine the fuel component of total energy cost, rather than actual fuel cost, and that neither of the transactions recorded megawatt hours for the associated off-system sales. Therefore, she stated that the Public Staff considers it reasonable to exclude these transactions from the analysis and that doing so did not change the overall percentage it recommended to the Commission.

Witness Peedin testified that, despite the removal of DNCP sales, its analysis is essentially similar to that performed by the Public Staff for the 1997 Stipulation addressing this issue (which was applicable to the 1997 and 1998 fuel proceedings) and the similar 1999 Stipulation (which was filed by PEC on June 4, 1999, in Docket No. E-2, Sub 748, and intended by the parties to be applicable to the 1999, 2000, and 2001 fuel cost proceedings). Similar analyses were performed for the 2002 through 2006 fuel proceedings. The methodology used in each of the above-mentioned Stipulations and subsequent fuel proceedings has been accepted by this Commission as reasonable for purposes of each fuel case since the beginning of 1997.

Witness Peedin stated that G.S. 62-133.2 requires that purchased power-related costs recovered through fuel adjustment proceedings include only the fuel cost component of those purchases. However, in its Order in Duke Energy Carolinas' 1996 fuel proceeding, the Commission stated that whether a proxy for actual fuel costs associated with these types of purchases would be acceptable in a future fuel adjustment proceeding would depend on "whether the proof can be accepted under the statute, whether the proffered information seems reasonably reliable, and whether or not alternative information is reasonably available." *Order Approving Fuel Charge Adjustment,* Docket No. E-7, Sub 575 (June 21, 1996).

Public Staff witness Peedin stated in her affidavit that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for determining the proxy fuel cost as described above. Because the sales made by marketers and other suppliers utilize the same types of generation resources that the utilities use to make their sales, the Public Staff believes that it is reasonable to assume for purposes of these proceedings that the fuel-to-energy cost percentage inherent in the purchases made by the utilities is similar to the percentage exhibited by the utilities' sales. Additionally, the information used by the Public Staff to determine the off-system sales fuel percentage was derived from the Monthly Fuel Reports filed with the Commission, and, in the opinion of the Public Staff, is reasonably reliable. Finally, the Public Staff is unaware of any alternative information currently available concerning the fuel cost component of marketers' sales made to utilities. Therefore, the Public Staff believes that the methodology used in the past Stipulations and in the analysis conducted for this proceeding meets the criteria set forth in the 1996 Duke Energy Carolinas Order for purposes of this case.

As part of its current review, the Public Staff analyzed the off-system sales information in several different ways. The Public Staff's analyses resulted in fuel percentages ranging from 56.61% to 60.53%, as set forth on Peedin Exhibit I. In response to questions from counsel for CUCA, witness Peedin stated that, in her opinion, it is appropriate to weight each of these various percentages equally. After evaluating all of the data and calculations, the Public Staff concluded that the off-system sales fuel percentage should be 58%. Witness Peedin was questioned by counsel for CUCA with regard to the off-system sales analysis, specifically the reasons for including certain sales by PEC and emergency sales by Duke Energy Carolinas and PEC in the analysis. Witness Peedin testified that, in preparing the analysis, she used the same methodology and procedures the Public Staff has used for the past ten years in these proceedings. Specifically, she stated that the fuel-to-energy percentages for sales questioned by CUCA were within the parameters that the Public Staff has consistently used for ten years.

The Commission concludes, as it has in past dockets, that the use of the utilities' own off-system sales to determine the proxy fuel cost for purchases from entities that do not provide actual fuel costs is reasonable and satisfies the requirements set forth in the 1996 Duke Energy Carolinas fuel case order for purposes of this proceeding. First, the results of applying the methodology can be accepted under G.S. 62-133.2. As Public Staff witness Peedin stated in her affidavit, the sales made by marketers and other relevant suppliers are sourced from the same types of generation resources that the utilities regulated by this Commission use to make their sales. The Commission thus finds it reasonable to assume for purposes of this proceeding that the fuel-to-energy cost percentage exhibited by the utilities' sales is similar to the percentage inherent in the sales made to Duke Energy Carolinas from the same types of generating resources. Second, the Commission concludes that the information used by parties to derive the fuel percentage is reasonably reliable. According to Public Staff witness Peedin's affidavit, this data was derived from the Monthly Fuel Reports filed by the utilities with the Commission, which are public reports taken from the utilities' financial records and subject to Commission review. Finally, no party to this proceeding has elicited evidence of any alternative information concerning the fuel cost component of purchases made from power marketers or other relevant sellers of power to Duke Energy Carolinas. Therefore, the Commission concludes that the methodology proposed by Public Staff witness Peedin meets the criteria set forth in the 1996 Duke Energy Carolinas fuel case Order and is reasonable for purposes of this proceeding as the method of determining the proxy fuel cost associated with sales from power marketers and similar sellers to Duke Energy Carolinas.

Given the fact that the Commission has concluded that the methodology proposed by Public Staff witness Peedin is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel percentage to be used in this case. As part of its current review, the Public Staff analyzed the off-system sales information in different ways. The Public Staff's analyses resulted in percentages ranging from 56.61% to 60.53% and, based on its analyses, the Public Staff concluded that 58% is an appropriate and reasonable fuel proxy percentage for purposes of this proceeding. Duke Energy Carolinas accepted the results of the analysis performed by the Public Staff and filed supplemental testimony and revised exhibits to reflect the 58% fuel percentage.

Based on the foregoing, the Commission concludes that it is reasonable, for purposes of this proceeding, to use the 58% fuel percentage as the basis for determining the proxy fuel costs for purchases from power marketers and other suppliers that do not provide actual fuel costs. Although counsel for CUCA questioned Public Staff witness Peedin regarding the inclusion of certain off-system sales transactions in the analysis, neither CUCA nor any other party elicited evidence demonstrating that inclusion of these transactions in the analysis was incorrect. Public Staff witness Peedin testified that the Public Staff has consistently used specific fuel-to-energy parameters in determining if the transactions should be removed from the off-system sales analysis. The Commission concludes that no persuasive evidence or rationale has been put forth that would support changing these parameters in the analysis for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-17

The evidence for these findings of fact is contained in the testimony and exhibits of Company witness McManeus and the affidavits of Public Staff witnesses Peedin, Johnson, and Lam.

Based upon the agreement between the Company and the Public Staff as to the appropriate levels of sales, generation, and unit fuel costs, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 4-9, the Commission concludes that adjusted test period system fuel expenses of $1,317,195,000 and a fuel factor of 1.6812¢/kWh, excluding gross receipts tax, are reasonable and appropriate for use in this proceeding. This approved fuel factor is 0.5780¢/kWh higher than the base fuel factor of 1.1032¢/kWh set in the Company's last general rate case, Docket No. E-7, Sub 487.

G.S. 62-133.2(d) provides that the Commission "shall incorporate in its fuel cost determination under this subsection the experienced over-recovery or under-recovery of reasonable fuel expenses prudently incurred during the test period . . . in fixing an increment or decrement rider. The Commission shall use deferral accounting, and consecutive test periods, in complying with this subsection, and the over-recovery or under-recovery portion of the increment or decrement shall be reflected in rates for 12 months, notwithstanding any changes in the base fuel cost in a general rate case."

Public Staff witness Johnson testified about the results of the Public Staff's investigation of the EMF. The EMF rider is utilized to "true-up" the recovery of fuel costs incurred during the test year pursuant to G.S. 62-133.2(d) and Commission Rule R8-55. The Public Staff's investigation included procedures to evaluate whether the Company properly determined its per books fuel costs and fuel revenues during the test period. These procedures included review of the Company's filing, prior Commission Orders, the Monthly Fuel Reports filed by the Company with the Commission, and other Company data provided to the Public Staff. Additionally, the procedures included review of certain specific types of expenditures impacting the Company's test year fuel costs, including nuclear fuel disposal costs, federally mandated payments for decommissioning and decontamination of Department of Energy uranium enrichment facilities, payments to non-utility generators, and purchases of power from other suppliers who may or may not have provided the actual fuel costs associated with those purchases. Also, the Public Staff's procedures included reviews of source documentation of fuel costs for certain selected Company generation resources. Performing the Public Staff's investigation required review of numerous responses to written and verbal data requests, as well as a site visit to the Company's offices. Witness Johnson stated in her affidavit that her investigation did not reveal any necessary adjustments to Duke Energy Carolinas' initially reported test year North Carolina retail fuel cost under-recovery or its proposed EMF.

As discussed above in the Evidence and Conclusions for Finding of Fact No. 10, Public Staff witness Peedin recommended that a factor of 58% be used to determine the fuel costs associated with power purchased from power marketers and other suppliers that did not provide the Company with the actual fuel costs associated with those purchases. In her supplemental testimony, Duke Energy Carolinas witness McManeus presented Revised McManeus Exhibit 6 setting forth the Company's revised recommended EMF increment. Witness McManeus testified that she applied the 58% fuel percentage proxy to the costs of purchased power from suppliers that did not provide actual fuel costs and to intersystem sales of power supplied by purchase for which actual fuel cost was unknown. The total under-recovery set forth on Revised McManeus Exhibit 6, page 1 of 2, is $56,203,000. Witness Peedin testified that the Public Staff did not disagree with the Company's adjustment. Witness Johnson testified that the Public Staff recommends that Duke Energy Carolinas' EMF increment rider be based upon a net fuel cost under-recovery of $56,203,000 and pro forma North Carolina retail sales of 54,172,678 MWH, as reflected in Revised McManeus Exhibit 6. Based upon the evidence in the record and the agreement of the Company and the Public Staff, the Commission concludes that Duke Energy Carolinas' reasonable North Carolina retail test period jurisdictional fuel expense under-collection is $56,203,000 and that 54,172,678 MWh is the reasonable level of test year adjusted North Carolina retail sales to be used to calculate the EMF increment rider.

Company witness McManeus calculated the EMF increment by dividing the $56,203,000 under-recovered fuel expense by the adjusted North Carolina jurisdictional sales of 54,172,678 MWh to arrive at an EMF increment of 0.1037¢/kWh, excluding gross receipts tax. Public Staff witness Johnson recommended the same EMF increment. The Commission concludes that the EMF increment of 0.1037¢/kWh, excluding gross receipts tax, is reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in a net fuel factor of 1.7849¢/kWh, excluding gross receipts tax, consisting of the prospective fuel factor of 1.6812¢/kWh and the EMF increment of 0.1037¢/kWh.

One other rate change, which has already been ordered in a separate proceeding, should be mentioned here. In the merger proceeding in Docket No. E-7, Sub 795, the Commission approved a one-year rate decrement of 0.2182 cents per kWh (including North Carolina gross receipts tax) for the benefit of Duke Energy Carolinas' North Carolina retail customers and provided for it to be in effect for service rendered from July 1, 2006 through June 30, 2007. The expiration of this decrement should be included in the public notice given in conjunction with this docket.

IT IS, THEREFORE, ORDERED:

1. That, effective for service rendered on and after July 1, 2007, Duke Energy Carolinas shall adjust the base fuel cost approved in Docket No. E-7, Sub 487, in its North Carolina retail rates by an amount equal to a 0.5780¢/kWh increase (excluding gross receipts tax), and, further, that Duke Energy Carolinas shall adjust the resultant approved fuel cost by an increment of 0.1037¢/kWh (excluding gross receipts tax) for the EMF increment. The EMF increment is to remain in effect for service rendered through June 30, 2008.

2. That Duke Energy Carolinas shall file appropriate rate schedules and riders with the Commission in order to implement these approved rate adjustments no later than 10 days from the date of this Order.

3. That Duke Energy Carolinas shall notify its North Carolina retail customers of these rate adjustments by including the "Notice to Customers of Change in Rates" attached as Appendix A as a bill insert with bills rendered during the Company's next normal billing cycle.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of June, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

mr061107.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 825

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Energy Carolinas, LLC Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	)))	NOTICE TO CUSTOMERS OF CHANGE IN RATES

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order in Docket No. E-7, Sub 825, on June 21, 2007, after public hearings, approving a fuel charge net rate increase of 0.1197 cents per kWh (including North Carolina gross receipts tax), or approximately $64,845,000 on an annual basis, in the rates and charges paid by the retail customers of Duke Energy Carolinas in North Carolina, effective for service rendered on and after July 1, 2007. The rate increase was ordered by the Commission after review of Duke Energy Carolinas' fuel expense during the 12-month period ended December 31, 2006, and represents actual changes experienced by the Company with respect to its reasonable cost of fuel and the fuel component of purchased power during the test period.

Additionally, the expiration on the same date of the decrement related to cost savings associated with the merger of Duke Energy Corporation and Cinergy Corporation approved in Docket No. E-7, Sub 795, results in a further increase of 0.2182 cents per kWh (including North Carolina gross receipts tax), or approximately $118,205,000 on an annual basis.

The net change in rates will be an increase of 0.3379 cents per kWh, which will be in effect for service rendered for the period of July 1, 2007 through June 30, 2008. The change in approved rates will result in a monthly net rate increase of approximately $3.38 for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of June, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DOCKET NO. G-9, SUB 528

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 IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, April 10, 2007, at 9:00 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Commissioners Lorinzo L. Joyner and Edward S. Finley, Jr.

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

Brian D. Heslin, 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 D. Szafran, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

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

BY THE COMMISSION: On August 1, 2006, 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 Keith P. Maust and the direct testimony and exhibits of David R. Carpenter 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, 2006.

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

On August 8, 2006, 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 3, 2006; set prefiled testimony filing dates; and required the Company to give notice to its customers of the hearing on this matter.

On August 9, 2006, the Attorney General filed his notice of intervention.

On August 15, 2006, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by the Commission on August 18, 2006.

On September 15, 2006, the Company filed a motion to suspend the procedural schedule as it applied to active parties and to hold the October 3, 2006 hearing for the sole purpose of receiving public testimony.

On September 18, 2006, the Commission issued its Order Granting Motion for Partial Suspension of Hearing Schedule, suspending the dates for filing testimony applicable to active parties, suspending the hearing procedures, and preserving October 3, 2006 for receipt of testimony of public witnesses only.

On October 2, 2006, the Company filed its affidavit of publication.

On October 3, 2006, a hearing was convened for the purpose of receiving public witness testimony. No public witnesses appeared at the hearing.

On February 22, 2007, the Company and the Public Staff filed a Joint Motion to Reestablish Hearing Schedule, requesting that the evidentiary hearing be set for April 10, 2007.

On March 1, 2007, the Commission issued its Order Reestablishing Hearing Schedule which set March 23, 2007, as the filing date for intervenor testimony and April 2, 2007, as the date for filing rebuttal testimony and rescheduled the hearing for Tuesday, April 10, 2007.

On March 23, 2007, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Assistant Director, Accounting Division, and the direct testimony of Thomas W. Farmer, Jr., Director, Economic Research Division, and Richard C. Ross, Public Utilities Engineer, Natural Gas Division.

On April 2, 2007, the Company filed the rebuttal testimony of David R. Carpenter and Bill R. Morris.

No other party filed testimony.

On April 10, 2007, the matter came on for hearing as scheduled and all prefiled testimony and exhibits were admitted into evidence. Company witnesses Keith P. Maust, David R. Carpenter, and Bill R. Morris and Public Staff witnesses Thomas W. Farmer, Jr., Richard C. Ross, and James G. Hoard testified at the hearing.

On May 25, 2007, the Public Staff and the Company filed a Joint Proposed Order, CUCA filed a brief and the Attorney General filed a notice stating that the Attorney General did not assert a position different from the position other parties have submitted in this case and would not, for that reason, file a separate brief or proposed order.

On June 27, 2007, CUCA filed a letter requesting expeditious resolution of the issues in this docket and the issuance of a final order.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. The Company is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. The Company is engaged primarily in the business of transporting, distributing and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. The Company has filed with the Commission and submitted to the Public Staff information in the form required by G.S. 62-133.4(c) and Commission Rule R1-17(k); however, the information filed and submitted contains substantial errors and omissions and has required extensive adjustments by the Public Staff.

4. The review period in this proceeding is the twelve months ended May 31, 2006.

5. The Company's gas costs and deferred account balances for the review period were not properly stated. Only after significant adjustments recommended by Public Staff witness Hoard and agreed to by Company witnesses Morris and Carpenter had been made were the Company's gas costs and deferred account balances for the review period properly stated.

6. During the period of review, the Company incurred total gas costs of $768,036,403.

7. At May 31, 2006, the Company had a debit balance of ($40,078,024) in its Sales Customers Only Deferred Account and a credit balance of $5,080,507 in its All Customers Deferred Account.

8. Piedmont operated a gas cost hedging program on behalf of customers during the applicable review period. Piedmont's hedging activities during the review period were reasonable and prudent.

9. At May 31, 2006, the Company had a credit balance of $22,251 in its Hedging Deferred Account.

10. It is appropriate for the Company to transfer the $22,251 credit balance in its Hedging Deferred Account to its Sales Customers Only Deferred Account.

11. It is appropriate that the Company maintain a credit balance of $40,200 in its NCUC Legal Fund Account.

12. The Company should apply $243,575 of supplier refunds to the NCUC Legal Fund Account.

13. Since January 2002, the Company has not reported to the Commission refunds it has received from suppliers as required by the Commission's March 12, 1992 order in Docket No. G-100, Sub 57.

14. Beginning with a supplier refund received by the Company in January 2002, the Company has not properly accounted for the refunds it has received from suppliers.

15. The May 31, 2006 balance of the Company's All Customers Deferred Account includes a credit of $1,238,220 for supplier refunds (including accrued interest).

16. After applying $243,575 of supplier refunds to the NCUC Legal Fund Account, the Company should have $1,681,122 of supplier refunds in an escrow account.

17. The Company has committed to filing timely reports of supplier refunds in the format set forth in Hoard Exhibit 5.

18. The Company has agreed to invest the supplier refunds held in escrow accounts in interest-bearing accounts.

19. The Company should file a proposal addressing the disposition of supplier refunds held in escrow not later than sixty days after the date of this Order.

20. The Company follows a number of complex accounting practices that may be unnecessary. The Company has agreed to modify two of these accounting practices: (1) the Company will discontinue its capitalization of storage demand charges, and (2) the Company will record revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts.

21. The Company has agreed to file with the Commission a report that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes.

22. The Company has agreed to file a report that details the components of the October 31, 2006, balance in Account 253.30 – Miscellaneous Deferred Credits.

23. During the review period, the Company failed to file accurate deferred account reports in a timely manner. The Company has committed to filing timely and accurate deferred account reports in the future. In that regard, the Company plans to implement changes in its gas accounting processes that are intended to facilitate its filing of timely and accurate reports.

24. The Company has reflected a credit in its All Customers Deferred Account for Compensation Received for Third Party Facility Damages for the prior review period, pursuant to the Commission's order in Docket No. G-9, Sub 507, and also has reflected a credit in that same deferred account for the amount of similar compensation received during the current review period. The Company should, on an ongoing basis, deduct the cost of gas and volumes associated with third party facilities damage in the determination of its lost and unaccounted for true-up entry.

25. The Company has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to the Company's system and has long term supply contracts with producers, marketers, and other suppliers.

26. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: the price of gas; the security of the gas supply; the flexibility of the gas supply; gas deliverability; and supplier relations.

27. The Company's gas purchasing policy and practices during the review period were prudent and its gas costs during the review period were prudently incurred.

28. The Company should be permitted to recover 100 percent of its prudently incurred gas costs.

29. Pursuant to G.S. 62-133.4(c), Piedmont must refund the May 31, 2006 $5,080,507 credit balance in its All Customers Deferred Account.

30. Piedmont attributes the shortcomings associated with its gas cost accounting system and related reporting to the use of an inadequate gas cost accounting spreadsheet program, an increasing workload due to acquisitions, the implementation of Sarbanes-Oxley, and the increasing sophistication of the Company's secondary market transactions.

31. Piedmont is taking action that it represents will remedy these gas cost accounting problems.

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 Maust and Carpenter. These findings are essentially informational, procedural or jurisdictional in nature and are based on uncontested evidence.

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-7

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter, Morris, and Maust; the testimony of Public Staff witnesses Hoard, Davis, and Farmer; and the provisions of the Commission's Rules.

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2006 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 including weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Company witness Carpenter testified that the Company filed with the Commission and submitted to the Public Staff a monthly accounting of the computations required by the Commission Rule R1-17(k). Witness Carpenter included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit DRC-1 to his direct testimony. Public Staff witness Hoard recommended adjustments to the Company's demand and storage costs, commodity costs, and deferred accounts. These adjustments resulted in changes to Mr. Carpenter's Exhibit DRC-1, which Public Staff witness Hoard incorporated in Hoard Exhibit 1.

With regard to the Company's demand and storage costs, Public Staff witness Hoard testified as follows:

> I have increased the Company's demand and storage costs for the Total Carolinas' (North Carolina and South Carolina) operations by $127,021 to reflect (1) a decrease related to the reclassification of $109,002 of Columbia Gulf volumetric transportation charges from demand costs to commodity costs, (2) an increase of $147,955 for Columbia Transmission storage capacity charges that were omitted by the Company, (3) an increase of $41,069 for Transco FT-NT charges that were omitted by the Company, (4) an increase of $42,024 related to an error in the amount of capacity release credits, and (5) an increase of $4,973 for various other small items. The net impact of the adjustments on the North Carolina demand and storage costs (after allocation to the North Carolina operations), as shown on Hoard Exhibit 1, Schedule 2, is an increase in the demand and storage costs by $95,137 to $76,158,761.

The Company agreed to witness Hoard's adjustments of demand and storage costs.

With regard to the Company's commodity cost of gas, witness Hoard testified as follows:

> I have increased the Total Carolinas' commodity costs shown by the Company on DRC Exhibit 1, Schedule 3, by $1,563,125 to reflect (1) a $1,163,196 increase that results from a decrease in the commodity cost of gas assigned to off-system sales, (2) an increase of $109,002 due to the reclassification of Columbia Gulf

volumetric transportation charges from demand charges to commodity costs, (3) a \$144,553 decrease for a credit amount reflected in the Company's JE#17 for November 2005, but not reflected in DRC Exhibit 1, and (4) an increase of \$435,483 to reflect the reclassification of the item described on Line 70 as "Adjustment for Estimates" to Schedule 4 of DRC Exhibit 1. The net impact of the adjustments on the North Carolina commodity cost of gas (after allocation to the North Carolina operations), as shown on Hoard Exhibit 1, Schedule 3, is an increase in the commodity cost of gas by \$1,330,312 to \$738,009,387.

The Company has agreed to witness Hoard's adjustments to the commodity cost of gas.

The Company has agreed to each of the adjustments recommended by witness Hoard. The Company and the Public Staff agree that during the review period Piedmont incurred gas costs of \$768,036,403.

Based on this evidence, the Commission concludes that the Company incurred \$768,036,403 in gas costs during the review period ended May 31, 2006.

Witness Carpenter testified that, as of May 31, 2006, the Company had a debit balance of (\$36,784,602) in its Sales Customers Only Deferred Account and a credit balance of \$3,483,071 in its All Customers Deferred Account.

Witness Hoard testified that the Company's deferred accounts should be adjusted to reflect certain adjustments, including adjustments (1) to recognize transactions reflected in the Company's May 31, 2006 Deferred Account Reports but not reflected in witness Carpenter's Exhibit DRC-1; (2) to reflect differences in the balances carried over from the prior annual review; (3) to correct computational or account posting errors; (4) to reflect the transfer of the hedging account balance approved by the Commission's order in the last annual review to the Sales Customers Only Deferred Account; (5) to correct cash out errors that have accumulated since Piedmont purchased North Carolina Natural Gas Corporation (NCNG) on September 30, 2003; (6) to reflect accrued interest on the NUI Transition Account; (7) to reflect compensation received by the Company for third party damages; (8) to reflect credits for supplier refunds received by the Company; and (9) to reflect the accrued interest effect of recording the correct deferred account entries in the appropriate accounting period. After reflecting these adjustments, witness Hoard determined that, as of May 31, 2006, the Company had a debit balance of (\$40,078,024) in its Sales Customers Only Deferred Account and a credit balance of \$5,080,507 in its All Customers Deferred Account. In response to questions posed by Commissioner Ervin, witness Hoard stated that he was not aware of any further needed adjustments to the deferred account balances.

Company witness Morris, in rebuttal testimony, stated that Piedmont accepts Public Staff witness Hoard's May 31, 2006 deferred account balances. Company witness Morris and Public Staff witness Hoard both testified that, after making the adjustments proposed by the Public Staff and accepted by the Company, the Company's gas costs and deferred account balances for the review period are properly stated.

No other party presented evidence on these issues.

Based on this evidence, the Commission concludes that the Company had a debit balance of ($40,078,024) in its Sales Customers Only Deferred Account and a credit balance of $5,080,507 in its All Customers Deferred Account as of May 31, 2006.

The Commission concludes that the Company has filed with the Commission and submitted to the Public Staff information in the form required by G.S. 62-133.4(c) and Commission Rule R1-17(k). This conclusion, however, does not constitute a determination by the Commission that Piedmont properly stated its gas costs and deferred account balances on its books of account during the review period. The Public Staff testified to a number of errors and omissions that it detected during its audit and recommended substantial adjustments. The Company accepted these adjustments. The Commission is disturbed by the number and severity of errors and omissions found by the Public Staff in its audit and will carefully monitor Piedmont's accounting performance until such time as the Commission is satisfied that similar errors and omissions are unlikely to reoccur.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-10

The evidence supporting these findings of fact is contained in the direct testimony of Company witnesses Maust and Carpenter, the rebuttal testimony of Company witness Carpenter, and the testimony of Public Staff witnesses Farmer and Hoard.

In his direct prefiled testimony, Company witness Maust indicated that the Company implemented hedges for the benefit of its customers during the review period consistent with the guidelines contained in the Company's established hedging plan as filed with the Commission. Public Staff witness Farmer testified that he reviewed the Company's testimony and exhibits, data request responses, and various related reports. He noted that in February 2006 NCNG's hedging program was merged with Piedmont's hedging program and that Piedmont operated one combined hedging program subsequent to that date. Witness Farmer testified that the Company's hedging activities were reasonable and prudent.

Company witness Carpenter stated in his direct testimony that the Company had a total debit balance of $6,476,392 in its Hedging Deferred Account at May 31, 2006. Public Staff witness Hoard testified that the Company's Hedging Deferred Account should be adjusted to reflect certain adjustments, including adjustments (1) to recognize transactions reflected in the Company's May 31, 2006 Deferred Account Reports but not reflected in DRC Exhibit 1; (2) to reflect differences in the balances carried over from the prior annual review; (3) to correct computational or account posting errors; (4) to reflect the transfer of the hedging account balance approved by the Commission's order in the last annual review to the Sales Customers Only Deferred Account; and (5) to reflect the accrued interest effect of recording the correct deferred account entries in the appropriate accounting period. After reflecting these adjustments, witness Hoard determined that, as of May 31, 2006, the correct balance of the Company's Hedging Deferred Account is a credit of $22,251. Witness Carpenter stated in his rebuttal testimony that Piedmont accepts witness Hoard's May 31, 2006 Hedging Deferred Account credit balance of $22,251 and recommended that the balance of the Hedging Deferred Account be transferred to the Company's Sales Customers Only Deferred Account. Public Staff witness Farmer agreed that the May 31, 2006 credit balance in the Company's Hedging Deferred Account of $22,251 should be transferred to the Sales Customers Only Deferred Account.

No other party presented evidence concerning the Company's review period hedging plan or its operations thereunder.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent and that the Company's Hedging Deferred Account credit balance of $22,251 as of May 31, 2006 should be transferred to the Company's Sales Customers Only Deferred Account.

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

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

Witness Hoard testified that the Company has not accounted for the NCUC Legal Fund Account in the manner prescribed by the Commission. Witness Hoard stated that the balance reflected on the Company's general ledger account for the NCUC Legal Fund Account has differed significantly from the account balance reported in the monthly Deferred Account Reports filed by the Company with the Commission. The Deferred Account Report reflected a debit balance of $159,514 as of May 31, 2006, whereas the general ledger reflected a credit balance of $16,587, a difference of $176,101. Witness Hoard stated that the difference arose primarily because the monthly Deferred Account Reports have not reflected any reimbursement payments to the Commission since March 1999, or the $278,856 of supplier refunds that were credited to the general ledger account in May 2006. Witness Hoard testified that the $278,856 amount recorded by the Company in May 2006 did not correctly reflect the amount of supplier refunds that should have been applied to the account and that this journal entry should be reversed. Witness Hoard testified that he had reviewed the detailed accounting records for the account dating back to March 1993, and has determined that $243,575 of supplier refunds should be applied to the account.

The Commission addressed the nature and purpose of the NCUC Legal Account in its Order Establishing New Accounting Procedures Under G.S. 62-48(b) issued February 23, 1993, in Docket No. G-100, Sub 57 (Accounting Procedures Order). The Commission required each LDC to establish a separate reserve account for purposes of reimbursing the Commission for expenses incurred pursuant to G.S. 62-48(b) and established a reserve account level for each LDC: $16,200 for NCNG; $19,800 for Public Service Company of North Carolina, Inc.; $22,800 for Piedmont; and $1,200 for North Carolina Gas Service. Because Piedmont has acquired NCNG and North Carolina Gas Service, the Commission concludes that the current established level for Piedmont should be $40,200.

Each LDC is required to credit the reserve account directly with supplier refunds up to the level established in the Accounting Procedures Order, charge the reserve account for amounts reimbursed to the Commission, and then credit the account when another supplier refund is received to bring the account back to the established level. The Commission required interest to be accrued on the account in the same manner and at the same rate as for the LDC's other deferred accounts.

Company witness Carpenter testified in rebuttal that the Company agrees with each of witness Hoard's recommendations regarding supplier refunds.

No other party provided evidence on this issue.

Based on the foregoing, the Commission concludes that the Company should apply $243,575 of supplier refunds to the NCUC Legal Fund Account

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-19

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

All LDCs are required, pursuant to the Commission's Order Regarding Handling of Supplier Refunds by Local Distribution Companies, issued March 12, 1992, in Docket No. G-100, Sub 57 (All LDCs Supplier Refunds Order) to file a report with the Commission that provides details regarding each supplier refund received within one week following the receipt of the refund. In his direct testimony, witness Hoard testified that, since letters dated January 23 and 25, 2002, filed in Docket No. G-100, Sub 57, the Company has not properly reported supplier refunds to the Commission. Witness Hoard recommended that such reports of supplier refunds be made in the format set forth in Hoard Exhibit 5. Company witness Carpenter stated that he agreed with witness Hoard's recommendations.

Witness Hoard testified that he also has determined that, beginning with a refund received in January 2002, the Company has not properly accounted for the refunds it has received from suppliers. Neither the deferred accounts nor the escrow accounts have been properly credited for the supplier refunds that Piedmont has received. He recommended that the All Customers Deferred Account be credited with $1,238,220 of supplier refunds (including accrued interest) that should have been recorded in the deferred accounts. In addition, he determined that the escrow account balance for Piedmont, as of January 31, 2007, after applying $243,575 of supplier refunds to the NCUC Legal Reserve Account, should be $864,009, and that the escrow account balance for NCNG should be $817,113, for a total of $1,681,122 for the two accounts. The Company agrees that these balances are correct.

No other party provided evidence on these issues.

Based on the foregoing, the Commission concludes that the Company has not properly reported supplier refunds to the Commission and has not properly accounted for the supplier refunds it has received since January 2002. In addition, the Commission concludes that the Company's periodic reports of supplier refunds should be filed on a timely basis in the format set forth in Hoard Exhibit 5. The Commission further concludes that the All Customers Deferred Account should include a credit of $1,238,220 for supplier refunds (including accrued interest), as reflected in Finding of Fact No. 7, and that the Company should have a total of $1,681,122 in supplier refunds in its escrow accounts.

The All LDCs Supplier Refunds Order in Docket No. G-100, Sub 57 required that the refunds held by LDCs in escrow accounts be invested in interest-bearing accounts. Witness Hoard testified that the Company has not invested the amounts held in escrow accounts in interest-bearing accounts. Witness Hoard testified that the Company should maintain a cash or investment account (a balance sheet debit account) that directly offsets each escrow account (a balance sheet credit account). He stated that, typically, supplier refunds should be invested in secure, interest-bearing, short-term securities. Interest earned on the account should then be accrued by offsetting journal entries to the cash/investment account and the escrow account. Essentially, the balance in the cash or investment account should always be the same as the balance of the escrow account. Witness Carpenter stated that he agreed with Mr. Hoard's recommendations.

No other party provided evidence on this matter.

The Commission concludes that Piedmont should invest the supplier refunds held in escrow accounts in interest-bearing accounts in accordance with its agreement.

Except where the Commission has ruled that the refunds should be handled differently, LDC's supplier refunds historically have flowed through to ratepayers. Pursuant to G.S. 62-158; the Commission may order that supplier refunds be set aside for natural gas expansion. Also, supplier refunds may be applied to the NCUC Legal Fund Reserve Account, an account established for the purpose of reimbursing the Commission for expenses incurred pursuant to G.S. 62-48(b).

In its Order Granting Petition Regarding Supplier Refunds issued February 21, 2002, in Docket No. G-9, Sub 459 (Piedmont Supplier Refunds Order), the Commission authorized Piedmont to return supplier refunds to ratepayers by crediting its deferred accounts for supplier refunds that it received. Effective November 1, 2005, the Commission ordered Piedmont in the Order Approving Partial Rate Increase and Requiring Conservation Initiative issued in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15 (Rate Case Order) to discontinue depositing the refunds in its deferred accounts and to hold the supplier refunds in an escrow account. NCNG, which was acquired by Piedmont on September 30, 2003, and which was merged into Piedmont on October 31, 2005, had been required by the All LDCs Supplier Refunds Order to hold its supplier refunds in an escrow account since prior to its acquisition by Piedmont.

The Company has been required, since the Rate Case Order became effective on November 1, 2005, to hold all supplier refunds that it receives in an escrow account. Public Staff witness Hoard recommended that the Commission direct the Company to make a proposal in a separate docket that addresses the appropriate disposition of the refunds.

Witness Carpenter agreed that the Company would file a proposal in a separate docket to address the appropriate disposition of the supplier refunds being held by the Company in the escrow accounts. On cross examination by CUCA, witness Carpenter stated that he was not aware of any expansion projects planned "at this time." He also agreed that the longer the Commission takes to ultimately refund the money to customers, the greater the difference between the identity of the ratepayers who receive the resulting refund and the identity of the ratepayers who bore responsibility for payments to the suppliers from whom the gas was purchased. However, on rebuttal, he stated that the Company would like to review its potential expansion projects before making such a filing.

No other party provided evidence on these issues.

In their Joint Proposed Order, Piedmont and the Public Staff noted that the Company is required to file a biennial report, pursuant to Commission Rule R6-5(11), detailing its plans for providing natural gas in unserved areas of its franchised territory in the near future and suggested that the Company should file its proposal regarding the disposition of supplier refunds held in escrow no later than the October 31, 2007 due date for its biennial natural gas expansion report. However, in light of the delay that has already occurred as a result of the Company's accounting and reporting shortcomings, the Commission requires a more prompt resolution to this issue. The Commission notes that, with previous biennial reports available, the Company will not be starting from scratch and should be able to comply with the filing due date set forth below.

Based on the foregoing, the Commission concludes that the Company should file a proposal regarding the disposition of supplier refunds held in escrow no later than 60 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-23

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

Public Staff witness Hoard testified that, for several years, the Company has not filed accurate and timely deferred account reports. He stated that, in his opinion, the root cause of the recurring problems that Piedmont has experienced with the filing of timely and accurate deferred account reports is that the Company's gas accounting system has not been fully adequate to address the complexities of its changing business practices. The Company also has employed several outdated and, in his opinion, overly complicated accounting practices that have compounded the shortcomings associated with the gas accounting system.

The Commission will first address the accounting practices of the Company that witness Hoard believes to be overly complex. Witness Hoard identified two such accounting practices. The first such practice involves the capitalization and amortization of storage demand charges, and the second involves the accounting treatment of revenues and the cost of gas related to secondary market transactions. Mr. Hoard recommended that the Company discontinue the first practice, and he recommended that the Company record the secondary market transactions in a series of non-utility accounts, instead of utility accounts. Witness Hoard also recommended that the Company review its gas accounting practices and file a report with the Commission that provides (1) the purpose of each regular monthly cost of gas and deferred account journal entry,

(2) an evaluation of whether the journal entry can be simplified or eliminated, and (3) a timeline for implementing any changes. The Company does not oppose these recommendations and no other party provided evidence on these issues.

Based on the foregoing, the Commission concludes that (1) the Company should discontinue the accounting practice of capitalizing storage demand charges and (2) the Company should record revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts. The Commission notes that the Company's fiscal year for financial reporting purposes ends October 31. To permit the Company to make a smooth transition to the new accounting practices, the Commission therefore concludes that the new accounting practices specified herein should be implemented no later than November 1, 2007, at the beginning of the Company's upcoming fiscal year. In addition, the Company should file a report with the Commission that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes. Such a report should be filed within 90 days of the order in this proceeding.

Witness Hoard testified that the Company has not been performing a proper reconciliation of the volumes delivered to the Piedmont system at its receipt points on the interstate pipeline system with the volumes delivered to its customers. In his direct testimony, witness Hoard stated, "In my view, this requires correction and must be addressed as soon as possible." In his discussion of the Company's accounting for customer imbalances, witness Hoard offered three suggested actions. He did not request that the Commission order the Company to take any specific actions.

Witness Hoard's first suggestion addressed the Company's accounting processes. He testified that the interface and communication between the Company's current gas cost accounting system and its other accounting systems, such as the customer accounting system, which contains customer billing data, and the gas costing system, which provides gas purchases details, are in need of extensive improvement. Upon cross-examination, witness Hoard testified that the accounting process changes should be implemented so that changes made to the system result in the most efficient and accurate accounting system. Witness Hoard further testified that the Company should be required to consult with the Public Staff during the development and implementation of changes to its gas accounting system.

In response, Company witness Carpenter testified that Piedmont agrees with many of witness Hoard's conclusions and is actively engaged in the process of revamping its entire gas cost accounting system and in creating processes to address these issues. Witness Carpenter described this revamping process as one that involves a detailed analysis of the results required from the system, an assessment as to how those requirements can be met, and the development of a new accounting system designed and implemented to satisfy those requirements. Witness Carpenter stated that the Company plans to fully consider and incorporate, to the maximum extent feasible, the accounting system recommendations offered by the Public Staff. Witness Carpenter further testified that Piedmont intends to communicate with the Public Staff should Piedmont conclude that it should not follow one or more of the Public Staff's recommendations and seek the Public Staff's input.

No other parties provided evidence on these issues.

Witness Hoard's second suggestion addressed deferred accounting reports. During the review period, the Company did not file accurate and timely deferred account reports. Furthermore, in response to questions posed by Commissioner Ervin, witness Carpenter testified that, at the time of the hearing, Piedmont was "a couple of months" behind on filing deferred account reports, which, pursuant to Commission Rule R1-17(k)(5)(c), are due 45 days after the end of each monthly reporting period. Witness Carpenter testified that, at the time of the hearing, the February report was due. He testified, "I would assume that we should have that up to date within the next two weeks." Those filings fell outside of the review period. The Commission notes that Piedmont's 2005 deferred account reports were filed in Docket No. G-9, Sub 503 and that the Company's 2006 deferred account reports were filed in Docket No. G-9, Sub 520. Of the seven reports covering the period June through December 2005, four of them were not filed within 45 days after the end of each monthly reporting period as required. There was no record in Docket No. G-9, Sub 503 of Piedmont's advising the Commission that its reports would be late or of any request for an extension of time to file the required reports. Of the five reports covering January through May 2006, three were not filed within 45 days. Again, there was no record in Docket No. G-9, Sub 520 of Piedmont's advising the Commission that its reports would be late or of any request for an extension of time to file the required reports.

The Company has committed to filing timely and accurate reports and, in that regard, the Company has committed to implementing changes in its gas accounting processes that will facilitate its filing of timely and accurate reports. Because the Public Staff has detailed knowledge of the Company's present gas cost accounting process, as well as the regulatory needs of the Commission, the Commission believes that the Company should consult with the Public Staff as the Company seeks to attain the accounting process improvement goals set forth in the testimony of witness Hoard.

As of the end of the review period in this docket, through the extensive efforts of the Public Staff, correct deferred account balances have been established. However, Piedmont is responsible under Commission Rule R1-17(k)(5)(c) for compliance with the Commission's requirements without the necessity for Public Staff assistance. The Commission recognizes that additional efforts will be required to rectify Piedmont's gas cost accounting shortcomings. However, with respect to the monthly deferred account report for September, due in mid-November and thereafter, the Commission requires Piedmont to submit accurate and timely monthly deferred account reports and will consider taking appropriate action, including the imposition of sanctions, in the event that the Company fails to make accurate and timely deferred account report filings from that date forward.

Witness Hoard's third suggestion addressed the issue of the sufficiency of transaction details pertaining to a specific liability account maintained by the Company, Account 253.30 – Miscellaneous Deferred Credits. Witness Hoard testified that Account 253.30 includes a wide assortment and variety of seemingly unrelated items, such as gas cost expenses, supplier refunds, deferred account entries, and other transactions. Witness Hoard recommended that the Company perform an in-depth analysis of Account 253.30 – Miscellaneous Deferred Credits and file a report with the Commission detailing the components of the account balance as of

October 31, 2006. The Company does not oppose this recommendation, and no other party provided evidence on the issue.

Based on the foregoing, the Commission concludes that the Company should file a report that details the components of the October 31, 2006 balance of Account 253.30 – Miscellaneous Deferred Credits within 90 days of the order in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Hoard.

Witness Hoard testified that, during the Company's last annual review, he was unable to determine how the Company accounts for compensation it receives for gas lost in connection with certain third party facilities damage or line breaks. As a result, the Commission ordered Piedmont to file a report describing how it accounts for this item. The Company filed the required report on June 12, 2006, in which it indicated that, during the review period ended May 31, 2005, the Company had lost 28,057 dekatherms of gas due to third party damage and had received $173,792 in related compensation. Witness Hoard testified in this docket that he reflected the $173,792 amount for the last annual review period as a credit in the current period to the All Customers Deferred Account. Witness Hoard testified that he had also reflected a $219,836 credit in the All Customers Deferred Account relating to the compensation received by the Company in the current review period. As far as the ongoing accounting procedures for this compensation are concerned, the Company stated in its report that such compensation would be reported as a credit to the cost of gas, and that the volumes of gas lost in connection with third party facilities damage would be tracked and would be included, as a component of gas supply, in the calculation of the lost and unaccounted for true-up journal entry. Witness Hoard testified that, when implemented, this manner of accounting for third party damage would then be consistent with the accounting treatment that the Commission has approved for the same third party facilities damage by Public Service Company of North Carolina, Inc., and that he agreed with Piedmont's proposed accounting treatment for such damage.

No other party presented evidence on this issue.

Based on the foregoing, the Commission concludes that the Company's proposed accounting treatment for compensation received in connection with third party facilities damage is appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25-28

The evidence supporting these findings of fact is contained in the testimony of Company witness Maust and Public Staff witness Ross.

Company witness Maust testified that the Company's gas purchasing policy is appropriately described as a "best cost" policy. This policy consists of five main components: price of gas, security of gas supply, flexibility of gas supply, gas deliverability, and supplier relations. Witness Maust stated that all of these components are interrelated and that the Company considers and weighs each of these five factors in establishing its entire supply portfolio.

Witness Maust further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements through the spot market and through long-term contracts. Long-term gas supplies are purchased under contracts ranging in term duration from one year (or less) to terms extending through October 2009. Spot gas contracts provide for little or no supply security because they are interruptible and short-term in nature. Long-term firm supplies are usually more expensive; however, they are also the most reliable and most secure source of gas. Some of the Company's firm contracts are for winter service only and some provide for 365-day (annual) service.

Witness Maust described how the interrelationship of the five factors affects the Company's construction of its gas supply 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 purchases generally serve the interruptible market. In order to weigh and consider the five factors, the Company must keep itself 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 affecting pipeline suppliers, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, attending conferences, and subscribing to industry literature.

Witness Maust stated that the Company's greatest challenge in applying its best cost policy is in dealing with future uncertainties in a dynamic national and regional energy market. Future demand for gas is affected by economic conditions, customer conservation efforts, weather patterns, regulatory policies, and energy industry restructuring efforts. Future availability and pricing of gas supplies are affected by overall demand, oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. Witness Maust further stated that the Company did not make any changes in its best cost gas purchasing policies or practices during the test period.

Witness Maust also indicated that, during the past year, the Company has taken several additional steps to manage its costs, including actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, actively renegotiating and restructuring its supply arrangements when possible, promoting more efficient 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.

Public Staff witness Ross testified that he had reviewed the Company's gas supply, transportation and demand contracts, as well as the Company's data request responses related to the Company's gas purchasing philosophies, customer requirements, and gas portfolio mixes. Based on this review, witness Ross testified that the Company's review period gas costs were prudently incurred.

No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were prudent and that its gas costs during the review period were prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact is contained in the testimony of Company witness Carpenter and Public Staff witnesses Ross and Hoard. No other party presented evidence on this issue.

The time required to complete the investigation and hearing for this annual review proceeding has been much longer than it should have been. Piedmont's annual review period covers a 12-month period ending May 31 of each year, and the hearing for Piedmont is ordinarily held on the first Tuesday of October. See Commission Rule R1-17(k)(6). In this proceeding, the Commission originally scheduled a hearing for October 3, 2006; however, on September 15, 2006, Piedmont filed a motion to suspend the hearing schedule "in order to permit outstanding and unresolved accounting issues between Piedmont and the Public Staff to be resolved prior to the filing of intervenor testimony and the evidentiary hearing." The Commission issued an order on September 18, 2006, granting that motion. Subsequently, on February 22, 2007, Piedmont and the Public Staff filed a joint motion to reestablish the hearing schedule, and the Commission issued an order on March 1, 2007, setting a new date for the filing of intervenor testimony and scheduling the hearing that it held on April 10, 2007. Therefore, in this proceeding, fourteen months have passed from the end of the review period to the date on which the Commission issues this order.

In pre-filed testimony, Piedmont witness Carpenter proposed to change rates to recover or refund the balances in the Company's deferred accounts.

Public Staff witness Ross testified that, in light of the adjustments to the deferred accounts recommended by Public Staff witness Hoard and in light of the passage of time since Piedmont's testimony was pre-filed, the current deferred account balances are different from those originally filed. Witness Ross stated that the best approach would be for Piedmont to make all of witness Hoard's recommended deferred account adjustments and, in a subsequent purchased gas adjustment or other appropriate proceeding, to implement such temporary rate increments or decrements as are then appropriate.

Witness Carpenter stated in his rebuttal testimony that he agreed with witness Ross. Witness Carpenter further stated that the goal of approving increments and decrements is to refund or surcharge customers, as appropriate, for balances remaining in the Company's deferred accounts at the end of the review period. Those balances vary from month-to-month, sometimes substantially, and, in this case, the passage of a complete winter heating season since the end of the review period makes the end-of-period balances much less useful in establishing meaningful rate adjustments. Witness Carpenter recommended holding any increment or decrement in abeyance at this time.

Under cross-examination by CUCA, witness Carpenter stated that he was unaware of any temporaries relating to the All-Customers Deferred Account. He further agreed that the $5 million balance identified by witness Hoard as being owed to the ratepayers as of May 31, 2006, would not be given back to ratepayers until a rate decrement is approved. Carpenter added that the balances in the deferred accounts are rolling balances and that the test period "is now quite a ways in the rear-view mirror." On redirect, witness Carpenter testified that he did not have updated information on the balance in the All-Customers Deferred Account since September 2006; however, customers owed Piedmont $2 million as of the end of September.

In their Joint Proposed Order, Piedmont and the Public Staff maintained that, while G.S. 62-133.4(c) anticipates that credit balances in a gas utility's deferred accounts will be refunded to customers, this subsection does not provide a specific timetable for such refunds. These parties proposed that the Commission postpone any rate changes until a future purchased gas adjustment or until after the next annual review proceeding.

In its post-hearing brief, CUCA noted that, with the corrections proposed by the Public Staff, the balance in Piedmont's All Customers Deferred Account at the end of the test period exceeded $5 million owed to customers. CUCA argued that G.S. 62-133.4(c) mandates that over-recoveries be refunded and that the Public Staff, by not recommending an immediate refund, was "gaming the system and manipulating rates in a manner that unfairly and unlawfully favors residential customers by taking advantage of seasonal usage variations and preventing industrial customers from receiving the full benefit to which they are entitled." Finally, CUCA argued that "the longer the Commission waits to refund the money to ratepayers, the greater the difference will be between the pool of recipient ratepayers and the pool of ratepayers who originally overpaid for their gas service."

The Commission concludes that steps must be taken in this docket to refund any outstanding over-recovery. G.S. 62-133.4(c) provides in relevant part:

> The Commission, upon notice and hearing, shall compare the utility's prudently incurred costs with costs recovered from all the utility's customers that it served during the test period. If those prudently incurred costs are greater or less than the recovered costs, the Commission shall, subject to G.S. 62-158, require the utility to refund any overrecovery by credit to bill or through a decrement in its rates and shall permit the utility to recover any deficiency through an increment in its rates.

The Commission recognizes that the deferred account balances are ever-changing, rolling balances. The Commission likewise recognizes that, in this case, significant time has passed since the end of the review period and that the balances in Piedmont's deferred accounts are no longer what they were at the end of the test period on May 31, 2006. Nevertheless, the Commission concludes that the mandatory language of the statute requires a refund to ratepayers in this docket. Moreover, the significant passage of time since the end of the review period results from deficient gas cost accounting practices of Piedmont, practices for which ratepayers bear no responsibility.

The Commission addressed this issue shortly after enactment of G.S. 62-133.4. In a 1993 prudency review conducted in Docket No. G-5, Sub 318, a \$1.6 million balance was due to PSNC in its Sales Customers Deferred Account and a \$2.6 million balance was due to customers in the All Customers Deferred Account. In its October 21, 1993 Order in that proceeding, the Commission concluded:

> Following the hearing, the Public Staff reconsidered its position in this matter and concluded that G.S. 62-133.4(c) is more appropriately interpreted to require that rates be decreased when an overcollection occurs.....
>
> CUCA filed a post-hearing brief in which it argues that under G.S. 62-133.4(c) the Commission must make rate adjustments in each annual gas cost review proceeding "to recoup any test period underrecovery and to disgorge any test period overrecovery." In making this argument, CUCA stresses that the statute uses the word "shall" as to both the refund of any overrecovery and the recovery of any deficiency. The Commission rejects CUCA's argument. CUCA ignores the words that follow "shall." The statute provides that the Commission shall "require" the utility to refund any overrecovery, but it provides that the Commission shall "permit" the utility to recover any deficiency. The term "require" means to direct, demand or compel while the term "permit" means to allow or consent, to give leave. Black's Law Dictionary 1140 and 1340 (6th ed. 1990). In this proceeding, Public Service has not asked to recover the undercollection in the deferred account for sales only customers, and the statute does not require the Commission to order such.

In Sub 318 the Commission did not approve a rate increment to recover the undercollection in the Sales Only Deferred Account because PSNC had not proposed one. However, the Commission did require a rate decrement to refund the \$2.6 million overrecovery in the All Customers Deferred Account because the statute required it.[1]

Piedmont and the Public Staff argue in this proceeding that the Commission could delay implementation of any decrement because the statute does not set a time limit for implementation. The Commission disagrees. The statute requires the utility to refund any overrecovery by credit or rate decrement, and the Commission concludes that such refund must be ordered when an overrecovery exists and when any party insists that a refund be made, as CUCA has requested in this case. The Commission notes that the statute does, however, allow for a rate decrement to refund an overrecovery, which means that the overrecovery may be refunded over time, rather than by an immediate, one-time credit. As a result, the Commission will order a decrement as advocated by CUCA.

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[1] The Commission notes that the Sub 318 Order simultaneously approved an offsetting rate increment, resulting in no effective rate change. PSNC had requested such an offset in its testimony "in order to avoid changing billing rates to implement changes of such small magnitude," and the Public Staff supported such an offset in Sub 318 because the All Customers Deferred Account balance was "relatively low" at the end of the test period and went negative thereafter. In this docket, unlike Sub 318, no request for an offset has been made. On the contrary, Piedmont and the Public Staff recommend a delay in implementing a decrement rather than seeking approval of an offsetting rate change.

The Commission finds no support for CUCA's contention that the Public Staff is "gaming the system" to favor residential customers. Although the Commission does not agree with the legal position advanced by the Public Staff in opposition to the result that we reach with respect to this issue, we find no basis for concluding that the Public Staff urged us to refrain from ordering the implementation of a decrement for the purpose of favoring one customer class over another. As a result, this CUCA argument does not provide any basis for our decision whatsoever.

Witness Hoard testified that, as of the end of the review period in this docket (May 31, 2006) and with his adjustments, a credit balance of $5,080,507 exists in the Piedmont All Customers Deferred Account and that a debit balance of $40,078,024 exists in the Sales Customers Only Deferred Account. In response to questions posed by Commissioner Ervin, witness Hoard testified that he was unaware of any additional work that would be needed to adjust the test period deferred account balances and that he was satisfied that the balances as of the end of the review period, as adjusted, had been properly stated.

The Commission therefore orders a decrement in Piedmont's rates to refund the credit balance in its All Customers Deferred Account as of May 31, 2006. The Commission will allow Piedmont two weeks from the date of this order to calculate and file an appropriate proposed rate decrement for Commission approval.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30 AND 31

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

The Commission is seriously concerned by the shortcomings in Piedmont's gas cost accounting system and practices, which were described at length in the Public Staff's and the Company's testimony in this docket. The deficiencies in the Company's gas cost accounting system and practices include obtuse gas accounting practices, which confuse even those who designed and used that system; omissions; errors; and failures to follow Commission orders.

Company witness Morris, in his rebuttal testimony, stated that "it is not uncommon for the Public Staff to detect and correct these types of errors in prudence review proceedings." He testified additionally, however, that "I think what may be unusual about this year is the scope and depth of the Public Staff's investigation, which likely led to a greater number of these types of adjustments." Company witness Carpenter testified that, in previous annual reviews, the Commission has always found that the Company's gas costs "as adjusted" were properly accounted for. In Finding of Fact 5 in the Commission's April 4, 2006 Order on Annual Review of Gas Costs in Docket No. G-9, Sub 507, the Commission explicitly stated that, "After making nine deferred account adjustments recommended by Public Staff witness Hoard and agreed to by Company witness Boggs, the Company has properly accounted for its gas costs incurred during the review period."

Commissioner Joyner questioned Public Staff witness Hoard on why accounting problems have come up repeatedly. Witness Hoard testified that, in the past, when the Public

Staff pointed out deficiencies, the Company had taken a "band-aid" approach. He added that the people involved did not want to change the system they had in place and that they continued to do things the same way, "adding more layers on top." Witness Hoard testified that the situation had "gotten worse" over time

Piedmont witness Carpenter also addressed the roots of the shortcomings in the Company's gas accounting. In his rebuttal testimony, he stated that "until last year, Piedmont's gas cost accounting function was supervised and directed under Piedmont's accounting department with no direct report responsibility to the personnel working in rates and regulatory affairs." He added that, historically, the gas accounting function was performed by one primary person with assistance from several other accountants utilizing a spreadsheet system developed within the Company. He asserted, "For many years this system did work," although he acknowledged that "it was not perfect and mistakes were made in how individual gas costs were recorded and reported." Mr. Carpenter testified that the Company tried to modify its spreadsheet system to address concerns raised by the Public Staff, but that the changes "may have even made the situation more problematic because they ultimately complicated the manner in which Piedmont's accountants reported gas costs to the Commission and reconciled those costs to the Company's financial statements."

In discussing the various accounting issues identified by the Public Staff, Piedmont witness Carpenter listed four causes for the problems in question. He stated that the amount and the complexity of the work involved with the Company's gas cost accounting function was effectively multiplied by a factor of two or three by the Company's acquisitions of NUI Corporation, NCNG, and Eastern North Carolina Natural Gas in recent years. Witness Carpenter added that the workload of Piedmont's accounting personnel was also increased by the passage of the Sarbanes-Oxley Act. He further stated that the level and sophistication of Piedmont's secondary market activities, which are handled by the gas accounting system, has dramatically increased over the last several years. Finally, he stated that the Company began to see evidence that the gas cost accounting spreadsheet system and the management structure that had been used for many years were "not fully adequate to efficiently manage, track, and report gas costs under the circumstances."

On cross examination by CUCA, Company witness Carpenter testified that Piedmont did "incorporate some of the NCNG people into our corporate office." However, he further stated that some NCNG accountants who were offered positions did not come to Charlotte "because they preferred their lifestyle and their location." In addition, witness Carpenter was asked by counsel for CUCA, "Why did it take Piedmont more than almost eight months to get to the point where you are implementing changes to make the kinds of corrections in his adjustments made back in the fall of 2006?" Mr. Carpenter's response was that as part of a reorganization, Piedmont had made a lot of significant changes last July 1 and "quite a fair number of people who had experience either left the Company or moved to different positions." He added, "When we re-staffed the Gas Cost Accounting Department, as I mentioned, it is difficult to find people with the proper background and knowledge to fill those positions. So quite honestly, we were running fairly shorthanded through the fall period."

On cross examination by Piedmont, witness Hoard testified that his adjustments to the All Customers Deferred Account included adjustments that benefited the customers and the Company. Witness Hoard also agreed that he had worked with Piedmont and its gas accounting system for many years and has been familiar with the personnel involved with the system for ten to fifteen years. When asked if he had any reason to believe that the mis-accounting of supplier refunds was an effort to divert or confiscate funds for the benefit of the Company he replied, "No, I don't."

Company witness Carpenter testified that over a period of years, Piedmont had taken several steps to address the problem. However, the resources applied did not produce the results needed. Witness Carpenter stated that the Company had "some unfortunate failures" in terms of personnel brought in. He stated that the Company has had "a couple of stop and starts with some personnel moves."

Mr. Carpenter testified that, as part of the reorganization last year, he and the Piedmont comptroller sat down with upper management and ascertained that the Company had a real need to greatly improve the processes of month-end closing and gas cost accounting. He stated that they were able to convince upper management that "this is the number one priority."

Mr. Carpenter further testified that, as part of Piedmont's overall restructuring, the Company brought the gas accounting under the direct responsibility of the regulatory affairs department, which he heads as the Managing Director of Regulatory Affairs. He, in turn, reports to Mr. Frank Yoho, the Senior Vice President of Commercial Operations. However, witness Carpenter testified that with regard to the gas accounting issues, he was "in reality, reporting to a team of Tom Skains, CEO; David [Dzuricky], CFO and Frank Yoho." Mr. Carpenter stated that Piedmont now feels it is more appropriate to have gas accounting report to the Regulatory Affairs area because "most of the things in gas cost accounting are driven by the regulation by the three states."

A Manager of Gas Cost Accounting who had previous gas cost accounting experience with PSNC was hired "a month ago," along with four new gas cost accountants, giving the Company a total of five gas cost accountants and one manager. Witness Carpenter stated that the Company was using these resources as well as those of the Public Staff and other LDCs to address the cost accounting issues. In response to questions posed by Commissioner Ervin, witness Carpenter stated that the Company had not conducted any studies to determine the appropriate staffing level for its accounting function other than having discussions with PSNC. He stated that Piedmont, through its knowledge of the task and responsibilities, had come up internally with what the Company thinks is a appropriate level of staffing.

Witness Carpenter further testified that Piedmont has also engaged a consulting firm, KP&G, "to review the entire financial end-of-month closing process with special emphasis being placed on the gas cost accounting function." That firm was scheduled to present recommendations "within six weeks and implementation of improvements will follow."

Witness Carpenter, when asked "How significant were the issues relating to Piedmont's gas cost accounting practices?" in his rebuttal testimony, replied "I think it depends on your perspective." He added, "From the customers' perspective, the impacts were largely buffeted by both the Public Staff's efforts to ensure accurate reporting and the method by which gas costs are passed through to customers." When asked if he was aware of any direct harm to customers that has resulted from Piedmont's accounting issues, he responded, "No." On cross examination by CUCA, witness Carpenter agreed that none of the roughly $5 million identified by witness Hoard had been returned to customers and none would be until a decrement was put in place. He further agreed that the longer the Commission waits to refund the money to customers, the greater would be the difference between the identity of those who paid the original gas costs in rates and those who receive the benefit of any future gas cost-related rate reductions.

Witness Carpenter stated that the Company was still two months behind on filing its deferred account reports. Witness Carpenter apologized for the failure to comply with Commission orders and stated, "You have my word that we will do that in the future."

In his rebuttal testimony, Company witness Carpenter stated that he did not believe that the Commission should formally order Piedmont to adopt Public Staff witness Hoard's recommendations. He stated, "We believe that the design and operation of the Company's accounting system is the primary and fundamental responsibility of Piedmont and its management." Chairman Finley, Commissioner Ervin and CUCA all questioned witness Hoard about whether the Commission should order changes in Piedmont's accounting system, including those suggested by the Public Staff. Witness Hoard testified that he thought that Piedmont should take the Public Staff's recommendations into account, but the Public Staff did not seek ordering paragraphs requiring Piedmont to adopt Mr. Hoard's suggestions.

No other party presented evidence on these issues.

The Commission determines that Piedmont should address and rectify the deficiencies and other problems outlined in detail above. These deficiencies have existed for some time, and the Public Staff's extensive audit in this docket has only served to bring them fully to the Commission's attention. Although the Commission commends the Public Staff for its efforts in correcting these accounting deficiencies and errors, the Public Staff's efforts should never have been necessary. If nothing else, the nine adjustments addressed in Sub 507 should have alerted Piedmont to the extent of the shortcomings in its gas cost accounting practices and should have led the Company to take corrective action without the necessity for Public Staff or Commission intervention. In this order, the Commission has explicitly found in accordance with the uncontradicted testimony that Piedmont's gas costs were not properly accounted for and that only through the extensive and time-consuming efforts of the Public Staff has a proper accounting been achieved. The Commission trusts that this finding will be sufficient to spur Piedmont to make any additional improvements necessary to ensure that the Company's gas costs are appropriately accounted for and that all reports required by the Commission are accurately prepared and submitted in a timely manner.

The various factors to which Piedmont witness Carpenter attributed the Company's gas cost accounting difficulties should not have resulted in the problems that have been revealed in this proceeding. The Company has an obligation to ensure that its staff is of sufficient size and possesses sufficient knowledge and skill to comply with its regulatory obligations. With regard to Piedmont's three acquisitions, Piedmont bears responsibility for completing the acquisitions while still fulfilling its responsibility to maintain and accurately report gas accounting information in a timely manner. Similarly, Piedmont must act to comply with the Sarbanes-Oxley Act while still fulfilling its responsibility to the Commission to maintain and report gas accounting information as required by statute, regulation, and Commission orders. The 25% of the net compensation associated with secondary market transactions that Piedmont is allowed to retain under the Commission's Order on Stipulation in Docket No. G-100, Sub 67 was intended to compensate local distribution companies for the additional time and expense involved in active participation in the secondary market as well as incenting such participation.[1] Finally, the fact that the Company began noting deficiencies in its ability to adequately account for and report gas cost information should have been a spur to improvement and does not constitute an adequate explanation for the problems that have been disclosed in this proceeding.

The Commission is particularly concerned by the Company's failure to comply with various provisions of earlier Commission orders. The Commission attempts to have valid reasons for ordering regulated utilities to act in a certain manner and expects those orders to be obeyed. Although the Commission understands that utilities have the right to challenge our orders on appeal or in other appropriate ways in order to protect their legal rights, simple non-compliance with such orders is not a valid option. The level of unexplained non-compliance with prior Commission orders revealed by the present record is troubling and will be taken into account in the event of any further non-compliance with such orders in the future.

Piedmont's failures in gas accounting put the Company's customers at risk. According to G.S. 62-33 and G.S. 62-34, the Commission has a responsibility to keep informed about the activities of the utilities subject to its jurisdiction and to investigate the books and records maintained by regulated entities. The relationship between the deficiencies in Piedmont's gas cost accounting and the Commission's ability to protect consumers through the exercise of these statutory powers should be obvious. The Company's failure to render timely and accurate gas cost accounting reports strikes at the heart of this Commission's ability to effectively oversee Piedmont's activities. The record in this proceeding demonstrates that Piedmont, over an extended period of time, has failed to adequately account for its gas costs and to comply with Commission filing requirements in a timely and adequate manner. Such deficiencies in the accounting information provided in accordance with North Carolina law hamper the Commission's ability to set rates that are fair and equitable to both customers and stockholders and to limit inappropriate fluctuations in the utility's rates.

While the Commission attempts to grant reasonable requests for extensions of time, Piedmont on too many occasions has simply chosen to ignore deadlines for filing reports without even attempting to request additional time to make the required filings, thus making it even more difficult for the Commission to carry out its regulatory duties. As a result, the Company's failure

[1] The Order on Stipulation stated, "The Commission recognizes, as noted in the comments of the LDCs, that this sharing ratio must serve two functions: it must compensate the LDCs for the additional administrative burden and operational complexities that can be attendant to negotiating and administering secondary market transactions, and it must provide an adequate incentive for LDCs to actively seek such transactions." The Commission notes that Piedmont retained approximately $8.4 million in net secondary market compensation in the review period and yet failed to properly account for its gas costs.

to account for and report its gas costs in an accurate and timely manner have put customers at risk.

A public utility's management bears responsibility for conducting the business of the utility. In carrying out this responsibility, management is fulfilling its responsibilities to both its own shareholders and to the Commission. However, without adequate accounting systems and capabilities, management lacks the necessary tools to adequately perform either function. In the event that a utility fails to appropriately keep track of its costs, it cannot propose legally sufficient rates. Furthermore, a persistent failure to comply with a regulatory agency's reporting rules can result in the assessment of a rate of return penalty or other sanctions, a result that would not be beneficial to shareholders. Thus, the Company's failure to adequately account for and report its gas costs in an accurate and timely manner could have adverse implications for shareholders as well.

No party has requested the imposition of penalties or sanctions in this proceeding. No party has requested that the Commission order Piedmont to employ the changes in the gas cost accounting practices presented by the Public Staff. The Commission is reluctant at this juncture to order the implementation of remedies that no party has proposed. Piedmont has been commendably forthright in acknowledging the deficiencies described above and has assured the Commission that these deficiencies will be promptly and adequately remedied. The Commission accepts Piedmont's assurances that it will remedy the conditions that led to the existing problems and relies on Piedmont's representations that these problems will be satisfactorily addressed in not imposing sanctions on Piedmont at this time. The accounting problems at issue in this proceeding can only be resolved through concerted efforts by relevant Piedmont personnel with complete support from upper management. However, while witness Carpenter testified that he had convinced upper management that "this is the number one priority," no member of Piedmont's upper management appeared before the Commission to testify in this docket or attended the hearing. The Commission expects Piedmont's upper management to ensure that the accounting issues revealed by the present record will be adequately addressed and will take appropriate action in future proceedings in the event that this fails to occur.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2006, under review in this proceeding, as adjusted by the Public Staff, is approved;

2. That the Company is authorized to recover 100% of its gas costs incurred during the period of review covered in this proceeding;

3. That the Company shall, within two weeks from the date of this order, file proposed tariffs implementing a decrement to rates sufficient to return the balance in the All Customers Deferred Account as of the end of the review period to customers over the course of the next twelve months;

4. That the Company shall file a proposal by October 31, 2007 in a separate docket that addresses the appropriate disposition of the supplier refunds held in escrow accounts;

5. That the Company shall file timely reports of supplier refunds. Such reports, which are due within one week following the receipt of the refund, shall be filed in the format set forth in Hoard Exhibit 5;

6. That the Company shall invest the supplier refunds held in escrow accounts in interest-bearing accounts;

7. That the Company shall discontinue its accounting practice whereby it capitalizes storage demand charges, effective no later than November 1, 2007;

8. That the Company shall change its accounting practices for secondary market transactions such that its accounting records will reflect the revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts, effective no later than November 1, 2007;

9. That the Company shall file a report that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes within 90 days of this Order;

10. That the Company shall consult with the Public Staff to attain the accounting process improvement goals set forth in the testimony of Public Staff witness Hoard;

11. That the Company shall file a report that details the components of the October 31, 2006 balance of Account 253.30 – Miscellaneous Deferred Credits within 90 days of this Order; and

12. That the Company will rectify the gas cost accounting deficiencies and shortcomings addressed above forthwith and that the Company shall file reports in compliance with Commission requirements in an accurate manner and on a timely basis henceforth.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

NATURAL GAS – ADJUSTMENT OF RATES/CHARGES

DOCKET NO. G-9, SUB 528

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-	)	ERRATA ORDER
133.4(c) and Commission Rule R1-17(k)(6)	)	

BY THE COMMISSION: It has come to the attention of the Commission that the Order on Annual Review of Gas Costs issued in this docket on August 1, 2007, contains a clerical error in Ordering Paragraph 4. Ordering Paragraph 4 of the Order reads as follows:

> 4. That the Company shall file a proposal by October 31, 2007 in a separate docket that addresses the appropriate disposition of the supplier refunds held in escrow accounts;

However, both Finding of Fact 19 and the discussion of Finding of Fact 19 in the Order state that the Company "should file a proposal addressing the disposition of supplier refunds held in escrow not later than sixty days after the date of this Order." Ordering Paragraph 4 of the Order should read as follows:

> 4. That the Company shall file a proposal not later than sixty days after the date of this Order in a separate docket that addresses the appropriate disposition of the supplier refunds held in escrow accounts;

The Commission finds good cause to order that Ordering Paragraph 4 be corrected as hereinabove provided.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah081507.03

DOCKET NO. G-53, SUB 0
DOCKET NO. E-65, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request of Glen-Tree Investments, LLC, for	)	
Approval of Master Metering Plan for The	)	ORDER APPROVING MASTER
Soleil Center Located at 4501 Creedmoor	)	METERING PLAN
Road, Raleigh, North Carolina	)	

BY THE COMMISSION: On October 11, 2007, Glen-Tree Investments, LLC (Applicant), filed a letter requesting the Commission to approve a master metering plan for the residential condominiums at The Soleil Center pursuant to G.S. 143-151.42. The Soleil Center will be a 42-story mixed-use development of which 22 stories contain 54 residential condominium units. It will also contain a hotel, a pool/fitness center, a spa, a restaurant, a convention center, and support facilities. Construction of The Soleil Center is scheduled for completion by the end of 2009.

On October 12, 2007, Deirdre L. McDaniel, a professional engineer registered in North Carolina and an employee of WMA Consulting Engineers Ltd. (Engineer), filed a signed and stamped letter stating that she had provided the technical information contained in the Applicant's letter of October 11, 2007. On December 6, 2007, the Engineer filed additional information in response to a Public Staff data request and stated that the proposed central systems are more efficient than the alternative individual systems.

According to the information provided by the Engineer, the metering plan for the Soleil Center consists of the following:

1) Individual electric service meters will be provided for each condominium unit for heating, lighting, and other appliances. The climate control designed by the Engineer for the condominium units is accomplished by vertical stacked fan coil units located in each dwelling unit and operates under each resident's individual control. Electric heating elements located in the fan coils provide heat for the condominium units.

2) Two electric master meters will measure electrical usage for the residential central cooling system and other systems serving common residential areas as well as non-residential loads that are not subject to the prohibition of master metering. The cooling system utilizes centrifugal chillers and roof mounted cooling towers that provide water to the fan coil units located in the condominiums. The estimated annual energy usage for this system is 294,862 kWh compared to 475,456 kWh for individual air conditioning systems. This represents approximately 38% savings in energy for the proposed central cooling system.

3) One natural gas master meter will measure natural gas usage for all residential purposes, including residential domestic hot water heating, residential corridor make-up air, residential cooking ranges, and residential stair pressurization. The central domestic hot water heating system consists of high efficiency gas-fired condensing boilers. The estimated annual energy consumption for the central system is 895,866 MBtu compared to 1,119,172 MBtu for individual water heaters. This represents approximately 19% savings in energy for the proposed central domestic water heating system. The residential corridor make-up air unit provides tempered air to the common residential corridors and consists of a single gas heat exchanger and gas humidification located in a central air conditioning unit on the 42nd floor. The estimated annual gas usage is 3,209,600 Mbtu. By definition individual systems would not be provided in place of this system. The residential natural gas cooking ranges have an estimated total annual gas usage of 2,400 Mbtu. This usage is approximately 0.058% of the overall gas usage for the condominiums.

4) Two electric meters will be provided for other non-residential loads such as the conference center, the spa, the hotel and the restaurant. Also, two electric meters will be dedicated to the fire pumps. These four electric meters are not subject to the master metering prohibition.

5) One natural gas meter will be provided for non-residential loads. This meter is not subject to the master metering prohibition.

With respect to residential natural gas cooking, the Applicant cites past decisions by the Commission in Docket No. G-45, Sub 0, The Florian Companies, and Docket No. G-50, Sub 0, Bloomsbury, LLC, where the Commission concluded that, "It appears doubtful that separate metering of natural gas service for cooking alone, even if practical, would have any impact on energy conservation." The Applicant also asserts that master metering of these minimal gas services does not contravene the spirit of G.S. 143-151.42.

The cost of the residential electrical and natural gas usage that will be master metered will be billed to the unit owners' association and will be a common expense. The association will allocate the cost to its members based on usage in accordance with the G.S. 47C-3-115(c) as measured by submeters. The General Counsel of the Commission has advised the Applicant that the exception from the definition of a "public utility" for a "nonprofit organization serving only its members" under G.S. 62-3(23)d applies to the association.

The Public Staff presented this matter at the December 17, 2007, Staff Conference. The Public Staff stated that it reviewed the request and recommended that the proposed electric and natural gas master metering plan be approved pursuant to G.S. 143-151.42.

Based on the foregoing, the Commission concludes that the request of Glen-Tree Investments, LLC, should be granted.

IT IS, THEREFORE, SO ORDERED.
This the 20th day of December, 2007

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah121707.01

Commissioner Sam J. Ervin, IV dissents in part.
Commissioner Lorinzo L. Joyner did not participate.

DOCKET NO. G 53, SUB 0
DOCKET NO. E-65, SUB 0

COMMISSIONER SAM J. ERVIN, IV, DISSENTING: Although I support the remainder of the Commission's decision in this proceeding, I am unable, for the reasons set forth in my dissents in In re Florian Companies, Docket No. G-45, Sub 0, Ninety-First Report of the North Carolina Utilities Commission: Orders and Decisions 418 (2001), and In re R. J. Griffin and Company, Docket No. G-49, Sub 0, Ninety-Sixth Report of the North Carolina Utilities Commission: Orders and Decisions 305 (2006), and the dissent of Commissioner Joyner in In re Bloomsbury, L.L.C., Docket No. G-50, Sub 0 (2006), to join that portion of the Commission's decision approving master metering for the natural gas cooking ranges. As I have said in prior cases addressing master metering issues, I believe that the Commission is obligated to apply G.S. 143-151.42 as written. I am unable to find any basis in the relevant statutory language for any sort of de minimis or "practicality" exception to the prohibition against master mastering contained in G.S. 143-151.42. In light of the fact that the only justifications offered to the Commission for approving the proposed master metering relating to the natural gas cooking ranges seem to involve de minimis and "practicality" considerations, I must respectfully decline to join the Commission's decision with respect to this limited issue. While I am confident that the Soleil Center will provide attractive and comfortable accommodations for its residents, "the General Assembly has defined the circumstances under which master metering is and is not permissible," and the "only avenue available . . . for seeking relief from the provisions of G.S. 143-151.42 runs through the General Assembly rather than the Commission." In re Florian Companies, Docket No. G-45, Sub 0, Ninety-First Report of the North Carolina Utilities Commission: Orders and Decisions 418, 423 (2001) (Commissioner Ervin, dissenting). As a result, I respectfully dissent from that portion of the Commission's conclusion that proposed master metering of the natural gas cooking ranges can be permitted under G.S. 143-151.42.

\s\ Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

DOCKET NO. G-55, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request of Insite Residential, LLC, for Approval	)	
of Natural Gas Master Metering for The Ardsley	)	ORDER APPROVING NATURAL
Condominium Project Located at 1025 Ardsley	)	GAS MASTER METERING
Road, Charlotte, North Carolina.	)	

BY THE COMMISSION: On November 29, 2007, Insite Residential, LLC, filed a letter requesting the Commission to approve natural gas master metering for a central hot water system at the Ardsley Condominium project pursuant to G.S. 143-151.42. The condominium project contains eight (8) historically renovated condominium units, which will be sold to individual purchasers. There will be no provision for natural gas appliances in the individual condominium units. The building is two stories in height and is located in the Myers Park area at 1025 Ardsley Road, in Charlotte, North Carolina. Presently under construction, the project had been scheduled for completion in November 2007.

The letter contained signed and stamped statements from Greg K. Andrews (Engineer), a Professional Engineer licensed in North Carolina. The Engineer stated that he performed calculations on two separate types of systems that supply hot water for a building with eight (8) units in a residential type environment, a central hot water system and individual hot water systems. The calculated annual natural gas load for the central system is 84 MMBtu compared to 85 MMBtu for eight (8) individual water heaters. This represents energy savings of approximately 1% as a result of utilizing a central water heating system.

The Public Staff presented this matter at the December 10, 2007, Staff Conference. The Public Staff stated that it had reviewed the request and recommended that the proposed natural gas master metering for the hot central hot water system be approved pursuant to G. S. 143-151.42.

Based on the foregoing, the Commission concludes that the request of Insite Residential, LLC, should be granted.

IT IS, THEREFORE, SO ORDERED.
This the 14th day of December 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah121207.02

DOCKET NO. G-5, SUB 300

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Public Service Company of North Carolina Inc.'s	)	ORDER DISSOLVING
Petition for Dissolution of Expansion Fund	)	EXPANSION FUND
Established Pursuant to N.C.G.S. 62-158	)	

BY THE COMMISSION: On February 15, 2007, Public Service Company of North Carolina, Inc. (PSNC), filed a Petition for Dissolution of Expansion Fund in this docket. PSNC asserted that its expansion fund pursuant to G.S. 62-158 was authorized by Commission order of June 3, 1993, in Docket No. G-5, Sub 300 and that PSNC has used its expansion fund to provide service to McDowell County (Docket No. G-5, Sub 337), to Haywood County (Docket No. G-5, Sub 372), to Alexander County (Docket No. G-5, Sub 391), to Madison, Jackson and Swain Counties (Docket No. G-5, Sub 410), and to Louisburg in Franklin County (Docket No. G-5, Sub 465). PSNC asserted that it has completed the Louisburg project, that it does not anticipate filing for any future expansion projects, and that it wishes to dissolve its expansion fund and place the remaining balance of $700,646 in its All-Customers Deferred Account for refund to customers.

Commission Rule R6-83(f) provides that upon petition for the dissolution of an expansion fund, "the Commission shall consider the status of service in the affected LDC's territory, the feasibility of further expansion and other relevant factors consistent with the intent of G.S. 62-158 and G.S. 62-2(9)." On March 19, 2007, the Commission issued an Order Requesting Comments and served a copy of that order on all parties who had intervened in this docket.

On April 18, 2007, Comments were filed by the Carolina Utility Customers Association, Inc. (CUCA), the Attorney General (AG), and the Public Staff, all supporting the Petition.

CUCA supported the Petition, stating, "Since PSNC does not anticipate filing any future expansion projects, granting PSNC's petition is consistent with the public interest."

The AG commented that because PSNC does not anticipate filing for future expansion projects qualifying for funds from an expansion fund, "there is not a reason to continue to hold a balance in the Fund." The AG supported the disbursement of all monies currently remaining in a manner that is fair and reasonably proportionate to the amounts contributed from each customer class.

The Public Staff supported PSNC's Petition. The Public Staff noted that PSNC serves all or parts of the twenty-eight (28) counties in its certificated franchised territory and that, after the completion of the Louisburg Expansion Project in 2006, PSNC believes that no other areas in its service territory appear to be eligible for the use of expansion funds. The Public Staff also stated that four North Carolina counties--Allegheny, Cherokee, Clay, and Graham--do not have natural gas service available and are unfranchised and that it is unaware of any projects under consideration that would extend gas service to those four counties. The Public Staff commented that it believed that PSNC has fulfilled its obligations consistent with the intent of G.S. 62-158 and G.S. 62-2(9) and therefore supported PSNC's Petition.

Upon careful consideration of the Petition, the comments and other relevant factors, the Commission finds good cause to grant the petition. The Commission notes that pursuant to G.S. 62-158, PSNC established an expansion fund, deposited supplier refunds into that fund, and filed projects to provide or extend service in McDowell, Haywood, Alexander, Madison, Jackson, and Swain Counties and to the town of Louisburg in Franklin County. The Commission notes that, in those projects' dockets, PSNC received approval to use approximately $46.1 million from its expansion fund to extend service to unserved portions of its service territory. PSNC has asserted that it does not anticipate filing for any future expansion projects.

IT IS, THEREFORE, ORDERED as follows:

1. That the Petition for Dissolution of Expansion Fund filed by PSNC in this docket is hereby granted;

2. That PSNC shall deposit the monies remaining in its expansion fund in its All-Customers Deferred Account for refund to customers; and

3. That PSNC shall file a final accounting for its expansion fund pursuant to Commission Rule R6-83(f).

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of May, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Wg052207.01

NATURAL GAS – MISCELLANEOUS

DOCKET NO. G-5, SUB 488

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Public Service Company of North Carolina, 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, August 14, 2007, at 10 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding, and Commissioners Lorinzo L. Joyner and Howard N. Lee

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Mary Lynne Grigg, Womble Carlyle Sandridge & Rice, 150 Fayetteville Street, Suite 2100, Raleigh, North Carolina 27602

William Pittman, The Pittman Law Firm, 1312 Annapolis Drive, Suite 200, Raleigh, North Carolina 27608

For the Using and Consuming Public:

Elizabeth D. Szafran, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On June 1, 2007, Public Service Company of North Carolina, Inc. (PSNC or Company) filed the direct testimony and exhibits of Candace A. Paton, Lead Analyst, Rates & Regulatory Affairs, and Terina H. Cronin, General Manager, Gas Supply & Sales, in connection with the annual review of PSNC's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On June 7, 2007, the Commission issued an order scheduling a hearing for August 14, 2007, setting other procedural deadlines, establishing discovery guidelines, and requiring public notice (Scheduling Order).

On June 22, 2007, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, which the Commission granted on June 27, 2007.

On June 25, 2007, the Attorney General filed a Notice of Intervention.

On July 23, 2007, the Company filed a letter of Notification of Delayed Public Notice.

On July 30, 2007, the Public Staff filed the testimonies of Thomas W. Farmer, Jr., Director, Economic Research Division; Julie G. Perry, Supervisor, Natural Gas Section in the Accounting Division; and Richard C. Ross, Public Utilities Engineer, Natural Gas Division.

On August 9, 2007, PSNC filed a letter requesting that the prepared direct testimony of PSNC witnesses Cronin and Paton and the prepared direct testimony of Public Staff witnesses Farmer, Perry, and Ross be entered into evidence in this proceeding without the need for the witnesses to appear at the hearing scheduled for August 14, 2007, and advising the Commission that PSNC, the Public Staff, the Attorney General, and CUCA agreed to the entry of witness testimony into the record without objection and to waive cross-examination of the witnesses.

On August 14, 2007, the Company filed its affidavit of publication.

On August 14, 2007, the matter came before the Commission for evidentiary hearing as scheduled. PSNC witnesses Cronin and Paton's testimony and exhibits were entered into the record, as were the testimony and exhibits of Public Staff witnesses Farmer, Perry, and Ross. No public witnesses attended the hearing. The Commission ruled during the hearing that the publication of the notice of hearing substantially complied with the requirements of Commission Rule R1-17(k)(6) and the Scheduling Order, and was, therefore, deemed to be sufficient publication for the purposes of this docket.

On September 25, 2007, the Public Staff and PSNC filed a Joint Proposed Order.

Based on the testimony, exhibits, 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 446,000 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, 2007.

5. During the period of review, PSNC incurred gas costs of $373,505,696 composed of demand and storage charges of $61,333,421, commodity gas costs of $316,259,865, and other gas costs of ($4,087,590).

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 $6,979,900, to its All Customers Deferred Account.

7. PSNC should record a correcting entry in the Sales Customers Only Deferred Account related to the uncollectible gas cost entries recorded during the review period, which will be subject to review in the Company's next annual review proceeding.

8. Except for the uncollectible gas cost adjustment, the Company has properly accounted for its gas costs incurred during the review period.

9. 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.

10. PSNC has a portfolio of long-term and supplemental short-term supply agreements with a variety of suppliers, including gas producers, independent producers, an interstate pipeline marketing company, and independent marketers.

11. At March 31, 2007, the Company had a credit balance of ($917, 207) in its Sales Customers Only Deferred Account and a credit balance of ($11,712,768) in its All Customers Deferred Account.

12. PSNC's hedging activities during the review period were reasonable and prudent.

13. As of March 31, 2007, the Company had a debit balance of $32,071,849 in its Hedging Deferred Account.

14. It is appropriate to transfer the $32,071,849 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 debit balance of $31,154,642.

15. The gas costs incurred by PSNC during the review period were prudently incurred.

16. Temporary rate decrements should be implemented in the Company's rates to refund the All Customers Deferred Account balance as a result of this proceeding.

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.

NATURAL GAS – MISCELLANEOUS

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 Perry. 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 Perry 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, 2007.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 THROUGH 8

The evidence supporting these findings of fact is found in the testimony of PSNC witness Paton and Public Staff witness Perry.

PSNC witness Paton's exhibits reflect demand and storage costs of $61,333,421, commodity costs of $316,259,865, and other gas costs of ($4,087,590) for a total of $373,505,696. Public Staff witness Perry agreed that total gas costs for the review period ended March 31, 2007, were $373,505,696. Ms. Perry further testified that PSNC properly accounted for its gas costs during the review period.

Public Staff witness Perry stated that the Company earned $9,306,533 of margin on secondary market transactions, including capacity release transactions and storage management arrangements, during the review period. Of this amount, $6,979,900 ($9,306,533 x 75%) was credited to the All Customers Deferred Account for the benefit of ratepayers.

Witness Perry further testified that, during the review period, PSNC recorded $1,681,485 of uncollectible gas costs in its Sales Customers Only Deferred Account. In response to an informal request by the Public Staff for additional information and documentation supporting the uncollectible gas cost entries recorded during the review period, PSNC discovered that the uncollectible gas cost entries had been calculated using an incorrect rate. Public Staff witness Perry recommended that PSNC record the correcting entry in the Sales Customers Only Deferred

Account in the month the correct amount is determined, and that the correcting entry be subject to review in the Company's next annual review proceeding.

The Commission concludes that, except for the uncollectible gas cost adjustment, PSNC has properly accounted for its gas costs during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 THROUGH 15

The evidence for these findings of fact is found in the testimony of PSNC witness Cronin and Public Staff witnesses Farmer, Perry, and Ross.

PSNC witness Cronin testified that approximately 47% 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 historical gas supply policy would be a "best cost" supply strategy, which is currently based on three primary criteria: supply security, operational flexibility, and cost of gas. Witness Cronin indicated that security of supply is the first and foremost criterion. She stated that, to maintain the necessary supply security for all of the Company's firm customers, PSNC has supply contracts with delivery guarantees and storage service contracts with delivery rights that provide total gas deliveries to PSNC, and that facilitate the full utilization of PSNC's firm interstate pipeline transportation and storage capacity. The rationale for this practice is PSNC's commitment to serve its firm market.

PSNC witness Cronin stated that the Company has long-term supply agreements and supplemental short-term agreements with a variety of suppliers, including producers, independent producers, an interstate pipeline marketing company, and an independent marketer. She stated that PSNC has increased its security of gas supplies by developing a diversified portfolio of long and short-term suppliers.

PSNC witness Cronin testified that maintaining the necessary operational flexibility in its gas supply portfolio is the second criterion. Flexibility is required because of daily changes in market requirements related to weather, industrial customers' operating schedules, and the Industrial customers' 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, witness Cronin stated that PSNC is committed to acquiring the most cost-effective supplies while maintaining the necessary security and operational flexibility to serve the needs of its customers. She noted that storage and the

Company's hedging program are also utilized to help manage price volatility to PSNC's sales customers.

PSNC witness Cronin testified that PSNC modified the time-driven component to its hedging strategy in May 2006 by extending the maximum number of future months to hedge from 12 to 18 months.

Public Staff witness Perry testified that during the review period the Company incurred net debits of $32,071,849 in its Hedging Deferred Account. Hedging activity recorded during the review period included $30,416,436 of costs associated with realized positions, $642,205 of interest expense accrued on the Hedging Deferred Account, $147,685 of payments for option premiums, $864,675 of payments for margin requirements, and $849 for brokerage fees. In regard to PSNC's hedging activities, Public Staff witness Farmer testified that he reviewed the Company witnesses' testimony and exhibits, data request responses, and related reports. Witness Farmer stated that PSNC's hedging activities were reasonable and prudent and that the net debits in PSNC's Hedging Deferred Account should be transferred to the Company's Sales Customers Only Deferred Account. Subsequent to the transfer, the Sales Customers Only Deferred Account would have a net debit balance of $31,154,642.

The Commission agrees with the Public Staff that PSNC's hedging activities during the review period were reasonable and prudent and that its hedging net debits incurred during the review period should be transferred to the Company's Sales Customers Only Deferred Account.

PSNC witness Cronin stated that the greatest challenges facing the Company today involve making decisions that will affect the Company and its customers in the future, such as decisions regarding long-term gas supply, capacity, and hedging in an environment of regulatory, legislative, and market uncertainty.

PSNC witness Cronin stated that the majority of PSNC's interstate pipeline capacity is obtained from Transcontinental Gas Pipe Line Corporation (Transco), the only interstate pipeline with which PSNC has a direct connection. The Company also has a backhaul transportation arrangement with Transco to redeliver gas, as well as storage service agreements with Dominion Transmission, Incorporated (DTI); Columbia Gas Transmission Corporation; East Tennessee Natural Gas Company; Dominion Cove Point LNG, LP; Saltville Gas Storage Company, LLC; and Pine Needle LNG Company, LLC. She noted that PSNC also has upstream firm transportation (FT) agreements with Texas Gas Transmission Corporation and Transco, both of which feed into DTI.

In regard to the gas supply contracts that support the FT capacity, witness Cronin indicated that PSNC has developed a portfolio gas supply strategy that includes the execution of long-term supply contracts, which support the Company's best-cost supply strategy. According to witness Cronin, as of November 1, 2006, the beginning of the winter heating season for the period under review, PSNC had approximately 218,317 dekatherms per day under contracts with ten major producers, one interstate pipeline marketing company, and one independent marketer. She testified that the contracts all have provisions to ensure that the prices paid are market sensitive.

NATURAL GAS – MISCELLANEOUS

PSNC witness Cronin testified that the gas supply and capacity portfolio that the Company has developed provides it the flexibility to meet its 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. During the review period, PSNC renegotiated pricing terms associated with one of its long-term supply agreements to ensure that charges accurately reflect market conditions. PSNC also entered into an agreement for an annual term with two new suppliers to replace service that expired during the review period;

2. PSNC continually evaluated various firm transportation and storage capacity options to ensure that future peak day requirements will be met;

3. PSNC continued to pursue and capture opportunities for capacity release and other secondary market transactions;

4. PSNC actively participated in matters before the Federal Energy Regulatory Commission (FERC), whose actions could impact the interstate pipelines and storage services on which PSNC currently holds, or could potentially hold, contracts where such matters may impact PSNC's rates and services to its customers;

5. PSNC continued to work with its industrial customers to transport customer-owned gas. Transportation services on PSNC's system permit gas to remain competitive with alternative fuels and allow PSNC to maintain throughput;

6. PSNC routinely communicated directly with customers, suppliers, and other industry participants, and actively monitored the industry using a variety of sources including industry trade periodicals; and

7. PSNC had frequent internal discussions among members of its senior management and that of its parent concerning gas supply policy and major purchasing decisions.

Public Staff witness Ross stated that he reviewed the Company witnesses' testimony and exhibits, PSNC's gas supply and transportation contracts, and the Company's responses to the Public Staff's data requests, including design day estimates, system load imbalances, forecasted gas supply needs, projected capacity additions and supply changes, and customer load profile changes. Public Staff witness Ross testified that based upon his investigation, he believed that PSNC's gas costs during the review period were prudently incurred.

The Commission further concludes that the gas costs incurred by PSNC during the test period ended March 31, 2007 were reasonable and prudently incurred and that the Company should be permitted to recover 100% of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact is found in the testimony of PSNC witness Paton and Public Staff witness Ross.

PSNC witness Paton testified that the Company does not propose new temporary decrements applicable to the All Customers Deferred Account since recently implemented pipeline rate changes would increase the Company's annual fixed transportation and storage costs by approximately $10.6 million above the level used to calculate the current fixed gas cost recovery rates. Witness Paton further stated that if a decrement was implemented to refund the $11.7 million over-collection it could cause a significant under-collection. Witness Ross testified that he recommended temporary decrements to the Company's rates to reduce the Company's All Customers Deferred Account balance. At the hearing, PSNC stated that it did not object to implementing the rate decrements recommended by Public Staff witness Ross.

Based upon the foregoing, the Commission concludes that it is appropriate for temporary decrements to be implemented in the Company's rates for the purpose of reducing the March 31, 2007 balance in PSNC's All Customers Deferred Account.

The Joint Proposed Order included an Exhibit 1 which calculated the decrements to the All Customers Deferred Account using the fixed cost allocation factors established in PSNC's last general rate case in Docket No. G-5, Sub 481. However, the Commission's Order on Reconsideration in that docket, issued since the filing of the Joint Proposed Order in this docket, resulted in changes to the fixed gas cost allocation factors for residential customers shown on Exhibit 1. The Company shall incorporate the new fixed allocation factors in the Order on Reconsideration in Docket No. G-5, Sub 481, and recalculate the residential temporary decrements in Exhibit 1. A Revised Exhibit 1 shall be filed with the Commission in this docket for information.

IT IS, THEREFORE, ORDERED as follows:

1. That PSNC's accounting for gas costs for the twelve-month period ended March 31, 2007, is approved;

2. That the gas costs incurred by PSNC during the twelve-month period ended March 31, 2007, were reasonably and prudently incurred, and PSNC is hereby authorized to recover 100% of these gas costs as provided herein;

3. That the Company shall record a correcting entry in the Sales Customers Only Deferred Account related to the uncollectible gas cost entries recorded during the review period, which shall be subject to review in the Company's next annual review proceeding;

4. That the temporary rate decrements shown on Exhibit 1 attached to the Joint Proposed Order shall be revised as described above, and a Revised Exhibit 1 shall be filed with the Commission no later than one week after the date of this Order; and

5. That temporary rate decrements shall be implemented in the Company 's rates to refund the All Customers Deferred Account balance as shown on Revised Exhibit 1 and effective for service rendered on and after November 1, 2007; and

6. That PSNC shall give notice to its customers of the rate changes allowed in this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of October, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG101907.02

DOCKET NO. G-40, SUB 66

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Frontier Energy, LLC, for	)	ORDER ON ANNUAL
Annual Review of Gas Costs Pursuant to G.S.	)	REVIEW OF GAS COST
62-33.4(c) and Commission Rule R1-17(k)(6)	)	

HEARD: Tuesday, March 6, 2007, at 10:00 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding, and Commissioners Robert V. Owens, Jr., and Howard N. Lee

APPEARANCES:

For Frontier Energy, LLC:

Stephon J. Bowens, Blanchard, Jenkins, Miller, Lewis, & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

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

BY THE COMMISSION: On November 27, 2006, Frontier Energy, LLC (Frontier or Company) filed the direct testimony and exhibits of Gregory L. Pittillo, Vice President and General Manager of Frontier, in connection with the annual review of Frontier's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) as modified for Frontier by the Commission's April 26, 2001 Order in Docket No. G-40, Sub 15.

On December 7, 2006, the Commission issued an order scheduling a hearing for March 6, 2007, at 10:00 a.m., setting other procedural deadlines, issuing discovery deadlines and guidelines, and requiring public notice.

On February 19, 2007, the Public Staff filed the direct testimony of Jeffrey L. Davis, Director, Natural Gas Division; David A. Poole, Accountant - Natural Gas Section, Accounting Division; and Thomas W. Farmer, Jr., Director, Economic Research Division.

On March 5, 2007, Frontier filed with the Commission a letter stating that the Company and the Public Staff had reached agreement on all issues in the docket and requesting that the prefiled testimony of the parties be entered into the record.

On March 5, 2007, Frontier filed Affidavits of Publication indicating that customer notice had been provided in accordance with the Commission's procedural order.

No other parties intervened.

The matter came on for hearing as scheduled. The testimony and exhibits of Frontier witness Pittillo and the testimony of Public Staff witnesses Davis, Poole, and Farmer were entered into the record.

Based on the testimony, exhibits, and the record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a limited liability company organized and existing under the laws of the State of North Carolina, headquartered in Elkin, North Carolina. Frontier is a subsidiary of Sempra Energy and is engaged in the business of transporting, distributing, and selling natural gas in North Carolina. Frontier is a public utility as defined in G.S. 62-3(23), and its public utility operations are subject to the jurisdiction of this Commission.

2. Frontier is a natural gas local distribution company (LDC), primarily engaged in the purchase, transportation, distribution, and sale of natural gas to approximately 660 customers in North Carolina, as of November 15, 2006.

3. Frontier has filed with the Commission and submitted to the Public Staff all information required by G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), and has complied with the procedural requirements of such statute and rule.

4. The review period for this proceeding is the twelve months ended September 30, 2006.

5. During the review period, Frontier incurred gas costs of $1,817,407, composed of Gas Purchases for Delivery of $1,570,550, Demand Charges of $216,298, Pipeline Transportation Charges of $15,401, and Scheduling Fees of $15,158.

6. The appropriate Deferred Gas Cost Account balance for Frontier as of September 30, 2006, is $15,978 owed to ratepayers. The balance is comprised of a beginning balance on October 1, 2005, of $336,105 owed to the Company, commodity cost over-collections of $278,723, transportation customer balancing over-collections of $94,952, accrued interest of $15,747, and prior period adjustments of $5,845.

7. Frontier has properly accounted for its gas costs during the review period.

8. The bundled supply contract Frontier has entered into has the flexibility to adapt to changing conditions and rapid growth while also providing dependable service to meet Frontier's customers' requirements.

9. Frontier has adopted a gas supply policy that it refers to as a "best evaluated cost" supply strategy. This gas supply policy is based upon flexibility, security/creditworthiness, and reliability of supply.

10. Frontier's decision not to implement a hedging program at this time was reasonable and prudent for this review period.

11. The gas costs incurred by Frontier during the review period were prudently incurred.

12. Frontier's plan to reduce the Deferred Gas Cost Account balance has been effective.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

These findings of fact are essentially informational, procedural, and jurisdictional in nature and were not contested by any party. They are supported by information in the Commission's public files and records and by the testimony and exhibits filed by Frontier witness Pittillo.

NATURAL GAS – MISCELLANEOUS

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings of fact is found in the testimony and exhibits of Frontier witness Pittillo, the testimony of Public Staff witnesses Davis and Poole, and the provisions of G.S. 62-133.4(c) and Commission Rule R-1-17(k)(6).

G.S. 62-133.4(c) requires Frontier to submit to the Commission specified information and data for a historical 12-month review period, including its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. In addition, Commission Rule R1-17(k)(6)(c) requires the filing of work papers, direct testimony, and exhibits supporting the information filed.

An examination of witness Pittillo's testimony and exhibits confirms that Frontier has complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), as applied to Frontier in the Commission's Order in Docket No. G-40, Sub 15. Witness Pittillo testified that Frontier filed with the Commission, and provided to the Public Staff, its updated monthly accounting of the computations required by Commission Rule R1-17(k)(5)(c) in a timely manner. Attached to witness Pittillo's testimony were schedules with the information required in gas cost review proceedings pursuant to the Commission's Order in Docket No. G-100, Sub 58, issued August 18, 1992. Public Staff witnesses Davis and Poole stated that they had reviewed the data filed by Frontier in this proceeding.

The Commission concludes that based on the testimony and exhibits and the Commission's Order in Docket No. G-40, Sub 15, Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and applicable provisions of Commission Rule R1-17(k) for the review period ended September 30, 2006.

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

The evidence for these findings of fact is found in the exhibits of Frontier witness Pittillo and the testimony of Public Staff witness Poole.

Frontier witness Pittillo's testimony and exhibits show that the components of Frontier's gas costs for the review period were as follows: Commodity Costs at City Gate of $1,570,550, Demand Fees of $216,298, Pipeline Transportation Charges of $15,401, and Scheduling Fees of $15,158. Public Staff witness Poole agreed with these amounts. The total resulting gas costs is $1,817,407.

Witness Poole further testified that each month, the Public Staff reviews the Deferred Gas Cost Account reports filed by Frontier for accuracy and reasonableness and performs many audit procedures on the calculations.

As of October 1, 2005, Frontier's beginning balance in its Deferred Gas Cost Account was $336,105 owed to the Company. After reflecting the commodity cost over-collections of $278,723, transportation customer balancing over-collections of $94,952, prior period adjustments of $5,845, and accrued interest of $15,747, Pittillo Exhibit I, Schedule 8 reflects an ending balance owed to ratepayers by the Company, as of September 30, 2006, of $15,978.

Public Staff witness Poole also testified that Frontier has properly accounted for its gas costs during the review period.

Based on the reasons stated above, the Commission concludes Frontier has properly accounted for its gas costs during the review period and that the deferred account balance as reported is correct.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-11

The evidence for these findings of fact is found in the testimony of Frontier witness Pittillo and the testimony of Public Staff witnesses Davis and Farmer.

Frontier witness Pittillo testified that Frontier's gas supply policy is best described as a "best evaluated cost" supply strategy. This gas supply strategy is based upon several criteria: flexibility, security/creditworthiness, reliability of supply, cost of the gas, and quality of supplier customer service. The foremost criteria for Frontier are flexibility, security/creditworthiness, and reliability of supply.

Witness Pittillo stated that this flexibility is required because of the daily changes in Frontier's market requirements caused by the unpredictable nature of weather, the production levels/operating schedules of Frontier's industrial customers, the industrial customers' ability to switch to alternative fuels, and the growth of customers during the test period. While Frontier's gas supply agreement has different purchase commitments and swing capabilities (i.e., the ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the seasonal, monthly, daily, and hourly changes in Frontier's market requirements. Witness Pittillo further testified that Frontier understands the necessity of having security of supply to provide reliable, dependable natural gas service, and has demonstrated its ability to do so. Frontier's supply strategy and its contract implementing this strategy have allowed Frontier to accomplish this objective.

In order to accomplish these objectives and implement its strategy during the review period, Company witness Pittillo testified that Frontier acquired all of its natural gas requirements from Prior Energy Corporation, a wholesale gas supplier with interstate capacity. This source of capacity has proven to be reliable even during the coldest peak winter days. The gas supply contract Frontier negotiated has the flexibility and reliability to meet its market requirements in a secure and cost effective manner. He testified that Frontier continues to evaluate its gas procurement practices and plans in order to meet short-term and long-term requirements in the future.

Public Staff witness Davis testified that he reviewed the testimony and exhibits of the Company's witness, the Company's response to the Public Staff's data request, and the Docket No. G-100, Sub 24A reports filed with the Commission. He stated that the Public Staff considers other information provided in data request responses to anticipate the Company's requirements in relation to future needs. Information received and reviewed includes design day estimates, forecasted load duration curves, forecasted gas supply needs, projections of capacity additions and supply changes, and customer load profile changes.

Witness Davis further testified that Frontier is still considered to be a relatively new company although it began construction of its natural gas transmission and distribution systems over nine years ago. As of July 2002, the Company completed the construction of its transmission system in its franchised area. The construction of distribution pipelines and provisions for service for new customers continues in all six franchised counties. Witness Davis further testified that the first customers to attach to Frontier's system were industrial customers, with relatively few residential and commercial customers. The majority of the industrial customers were offered initial conversion rates to switch from alternative fuels and were offered negotiated rates to remain on natural gas service, and are designated to be interruptible should the system requirements justify it.

Witness Davis also stated that, given this type of customer profile, firm long-term capacity contracts similar to those used by the mature LDCs would have been expensive given the fact that firm capacity demand costs would have to be paid whether or not the interruptible load was using gas for a given month or if the load was lost to alternative fuels because of price sensitivity. Moreover, system throughput continues to rise as more customers are added to the system. In this environment, flexibility of supply to adapt to changing conditions and growth is essential. The contract that Frontier has entered into with its supplier has flexibility while providing dependable service to meet Frontier's customers' requirements.

Company witness Pittillo testified that Frontier did not engage in any hedging activities during the review period. He stated that, as a small greenfield LDC, Frontier must carefully weigh the risk of its bundled (full) service load being less than one standard hedging contract of 10,000 dekatherms (dts) in any given month. Witness Pittillo stated that, for the review period, Frontier was below 10,000 bundled service dekatherms for (6) six months and above 10,000 dts for six (6) months. According to witness Pittillo, had Frontier hedged during the winter months of November through March, 37% to 75% of its bundled service load would have been at risk (i.e., the volumes hedged would have been higher than prudent). Witness Pittillo further stated that as Frontier matures and its bundled service load grows, it will continue to give hedging closer attention.

Public Staff witness Farmer testified that Frontier's actions related to hedging were reasonable and prudent for this review period. Witness Farmer recommended that Frontier continue to develop its hedging expertise, closely monitor gas prices, evaluate hedging opportunities, and pursue hedges when conditions warrant.

Based on the Public Staff's investigation and review of the data filed in this docket, Public Staff witness Davis testified that Frontier's gas costs during the review period were prudently incurred.

The Commission concludes that the gas costs incurred by Frontier during the twelve-month period ended September 30, 2006, 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. 12

The evidence for this finding of fact is found in the testimony of Public Staff witness Poole.

The Deferred Gas Cost Account balance has decreased by $352,083 from the prior annual review. Witness Poole testified that Frontier's plan to reduce the Deferred Gas Cost Account has been effective, and the Public Staff continues to monitor Frontier's Deferred Gas Cost Account balance due to concerns raised in prior annual reviews over the increasing balance.

The Commission concludes that Frontier's efforts have been effective in reducing the Deferred Gas Cost Account balance.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs during the review period ending September 30, 2006, is approved; and

2. That the gas costs incurred by Frontier during the twelve-month period ended September 30, 2006, were reasonable and prudently incurred, and Frontier is hereby authorized to recover its gas costs as provided herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of April, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

wg041907.01

DOCKET NO. G-54, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of West Developers, LLC, 104 Lake	)	
Cliff Court, Raleigh, North Carolina 27513	)	ORDER APPROVING NATURAL
for Approval of Natural Gas Master Metering	)	GAS METERING PLAN
Plan for The Residences at West	)	
Condominium Project	)	

NATURAL GAS – MISCELLANEOUS

BY THE COMMISSION: On October 26, 2007, West Developers, LLC (Applicant), filed a letter requesting that the Commission approve a natural gas metering plan for a condominium building project. The project is The Residences at West, 400 N. West Street, Raleigh, consisting of 170 single family residential condominium units ranging in size from 700 to 1,950 square feet each on floors five through sixteen, parking, and 18,900 square feet of retail space. Construction began February 5, 2007, and is scheduled for completion by late summer 2008. The Applicant stated that this request is very similar to others approved by the Commission.

Attached to the Applicant's October 26, 2007, filing was a letter dated October 17, 2004, from Triangle Engineering Associates, PLLC and signed by Rick Keil, who is a Professional Engineer registered in North Carolina. This letter stated a basic description of the proposed system and metering plan for the project.

On November 16, 2007, the Applicant made a supplemental filing in response to a Public Staff data request. This filing stated that gas service will be provided by Public Service Company of North Carolina, Inc., that there are no gas appliances in the residential units, and that separate electric meters will be provided for each residential unit.

Attached to the Applicant's November 16, 2007, filing was a letter dated November 16, 2007, signed and sealed by the Engineer. This letter stated that the natural gas metering plan additionally consists of one meter to serve a rooftop boiler and one meter to serve each retail space. The heating/cooling system was described as consisting of a two-pipe condensing water loop maintained between 60-100 degrees Fahrenheit and connected to water-source heat pumps for the individual spaces. For the proposed system, the cooling energy efficiency ratio (EER) was stated as 15.1, the heating coefficient of performance (COP) was stated as 5.4, and the energy consumption was stated as 4,929 million British thermal units per year (MMBtu/yr). For comparative individual air source heat pump systems, the EER was stated as 11.0, the COP was stated as 3.5, and the energy consumption was stated as 6,701 MMBtu/yr.

The Public Staff presented this matter at the December 10, 2007, Staff Conference. The Public Staff stated that it had reviewed the request and recommended that the proposed natural gas master metering plan be approved pursuant to G. S. 143-151.42.

Based on the foregoing, the Commission concludes that the request of West Developers, LLC, should be granted.

IT IS, THEREFORE, SO ORDERED.
This the 14th day of December 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah121207.01

NATURAL GAS – RATE INCREASE

DOCKET NO. G-5, SUB 481

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of Public Service Company of	) ORDER ON RECONSIDERATION
North Carolina, Inc., for a General Increase	) AMENDING ORDER AND
In its Rates and Charges	) SCHEDULING NEW HEARING

BY THE COMMISSION: This docket is a general rate case proceeding for Public Service Company of North Carolina, Inc. (PSNC or the Company). The Commission issued its Order Approving Partial Rate Increase (rate case order) on October 23, 2006, and PSNC has now moved for reconsideration of the rate case order pursuant to G.S. 62-80.

The October 23, 2006 rate case order found that a joint stipulation submitted by PSNC, the Public Staff, and Carolina Utility Customers Association, Inc. (CUCA), to which the Attorney General did not object, provided a just and reasonable resolution of all issues in the case, and the Commission adopted the terms of that stipulation. Among other things, the stipulation provided for an increase in PSNC's annual revenues of $15,188,102, offset by $9,220,399 of reductions in fixed gas costs, for a net increase in rates and charges of $5,967,703, and the rate case order approved this revenue requirement. The order approved a rate design calculated to produce the annual revenue requirement found to be just and reasonable. That rate design includes new rate classifications for residential customers. The new residential rate design consists of a Residential Value Rate (Rate 105) and a Residential Standard Rate (Rate 110). Residential customers who use at least 24 therms over the summer months of June, July, and August qualify for Rate 105, which is approximately $0.12 per therm lower than Rate 110. Both residential rate schedules include a monthly facilities charge of $10.00 per month.[1] The rate case order found this residential rate design to be fair and reasonable.

On April 18, 2007, PSNC filed a Petition to Amend Order and Defer Rate Differentials in this docket, requesting that the Commission reconsider the rate case order pursuant to G.S. 62-80. By the Petition, PSNC asserts that the residential rate design adopted in the rate case order gives rise to the possibility that some customers may increase their natural gas consumption during the summer for the sole purpose of qualifying for the lower Rate 105. PSNC asserts that the Company promotes the efficient use of natural gas and believes that its customers should manage their energy consumption wisely. To address the unintended consequences of the new residential rate design, PSNC asked the Commission to amend the rate case order to charge all residential customers at Rate 105 effective as of June 1, 2007. PSNC also proposed in its Petition to defer the rate differentials between Rates 105 and 110 (including related WNA differentials), with interest at the net-of-tax overall rate of return, until the

[1] As explained in the rate case order, PSNC originally proposed a facilities charge of $15.00 per month for residential customers, arguing that many of its costs are fixed and that recovery of more fixed costs in the facilities charge would minimize variances in customer bills and improve the Company's margin stability. Upon objection by a party, PSNC agreed to a facilities charge of $10.00 per month as part of the rate design contained in the stipulation and approved by the Commission.

Company's next general rate case, at which time PSNC would recommend a new residential rate design and seek recovery of the deferred amounts from the residential customer class.

The Presiding Commissioner issued an order on May 2, 2007, scheduling an oral argument on the Petition. The oral argument was held as scheduled on May 14, 2007. PSNC and the Public Staff appeared at the oral argument. Neither the Attorney General nor CUCA appeared; however, PSNC's attorney stated that she had spoken with counsel for the Attorney General and CUCA and they had stated to her that they did not oppose the proposal. PSNC and the Public Staff presented argument and responded to questions from the Commission. PSNC estimated the annual revenues to be deferred at approximately $8.1 million with interest. The Public Staff stated that it supports PSNC's proposal.

At the argument, PSNC initially amended its request by committing to discontinue the proposed deferrals within three years, within which time the Company would either file a new general rate case or propose a restructuring of residential rates. In response to concerns expressed by Commissioners during the argument, PSNC again amended its request to commit to either file a general rate proceeding or request a rate restructuring so as to discontinue the deferrals by November 1, 2008.

G.S. 62-80 provides that the Commission "may at any time upon notice to the public utility and to the other parties of record affected, and after opportunity to be heard as provided in the case of complaints, rescind, alter or amend any order or decision made by it." By this statute, the Commission has authority, upon its own motion or upon motion by any party, to reconsider a previously issued order, upon proper notice and hearing and upon the record already compiled, without requiring the institution of a new and independent proceeding by complaint or otherwise. State ex rel. Utilities Comm. v. Edmisten, 291 NC 575, 582 (1977). G.S. 62-80 "is broad enough to permit the Commission to modify and amend its order, even substantially, for the reason that, upon further consideration of the record before it, the Commission comes to the opinion that its order was due to the Commission's misapprehension of the facts, or disregard of facts, shown by the evidence received at the original hearing." Id. at 584. By the terms of G.S. 62-80, "the Legislature intended that the Commission may change an order in some respects without considering all factors that must be considered in a general rate case. The statute does not limit changes in orders to those that have not become final." State ex rel. Utilities Comm. v. Public Service Co., 59 NCApp 448, 451 (1982). An order may be reopened for the purpose of reconsidering one aspect of the order while the order remains in other respects a final order. Id. at 453.

By its motion for reconsideration and at oral argument, PSNC asserts that the new residential rate design has provoked numerous complaints. "Many of these customers stated that they would be better off to waste gas in the summer months to qualify for the Value Rate." The Commission did not intend such an effect when it approved this residential rate design. The fact that the residential rate design approved by the Commission may result in the inappropriate wasting of gas represents a misapprehension of fact justifying reconsideration of the residential rate design aspects of the rate case order. The Commission will undertake such reconsideration.[1] In all respects other than the residential rate design, including the revenue requirement approved for the Company, the rate case order remains final.

PSNC has proposed two forms of relief upon reconsideration. First, it proposes that the Commission move all residential customers to Rate 105 effective June 1, 2007. June 1 is the start of the summer months during which some Rate 110 customers might be tempted to use more gas, or to "waste" gas, in order to get assigned to the lower Rate 105. The Commission will allow this relief and will authorize the transfer of all Rate 110 customers to Rate 105 as of June 1, 2007.

The second relief proposed by PSNC is the creation of a deferred account to record the rate differentials between Rates 105 and 110. PSNC has committed to discontinue these deferrals by November 1, 2008. By that time, PSNC will take action to establish a new residential rate design -- either by a new filing in this docket or as part of a new general rate case -- and PSNC will provide for collecting the deferred account balance, with interest, as part of that action. For the reasons discussed hereinafter, the Commission concludes that this proposal should be rejected. The Commission will authorize a deferred account, but will require that deferrals end by November 1, 2007.

In the present circumstances, the Commission concludes that a deferred account should only be authorized as a temporary measure ancillary to the establishment of new, proper residential rates. Barring good cause, today's customers should pay today's cost of utility service. PSNC's proposal would leave the establishment of a proper rate design unresolved for a substantial period of time, with the rate differentials recorded in the interim to be collected in some manner, as yet undetermined, in the future. Having undertaken reconsideration of PSNC's residential rate design, the Commission believes that it should proceed to establish a new residential rate design forthwith. The Commission has heard no persuasive reason for delay. The options for new residential rates are relatively few, several of them were identified during the oral argument, and PSNC indicates that it has already begun to evaluate them. PSNC expressed concerns with changing rates too frequently, but this is not a persuasive consideration since rates customarily change from time to time throughout the year to reflect changes in the benchmark cost of gas and the balances in PSNC's gas cost-related deferred accounts.. The Commission concludes that new residential rates, based upon expert evidence and designed to allow PSNC an opportunity to collect its approved revenue requirement, should be established by November 1, 2007, when gas usage will increase with the beginning of the winter heating season. There is ample time to accomplish this goal if the Commission and all parties proceed without delay.

Although the Commission has made the present decision on the basis of the original record and the oral argument, new evidence will be necessary in order to establish a new residential rate design. G.S. 62-80 permits the taking of such additional evidence. See, e.g., Public Service Co., 59 NCApp at 452, where additional evidence was heard as part of the

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[1] Although the Commission has decided to reconsider the rate case order, the Commission expresses no opinion at this time as to the nature of the final rate design that may be approved herein. Upon reconsideration, the Commission may rescind, alter, amend, or refuse to make any change to its earlier order.

Commission's reconsideration. In this case, the Commission will establish a procedural schedule providing for the filing of proposed residential rate schedules and the convening of an evidentiary hearing thereon. The Commission will proceed in the original rate case docket; however, considering the history of this issue and the interests of openness and fairness, the Commission will not limit the further hearing to the parties that have already intervened. The Commission will provide for a new public notice of PSNC's rate proposal and will allow a new opportunity for public witnesses and interventions.

IT IS, THEREFORE, ORDERED as follows:

1. That the Commission hereby reconsiders the residential rate design approved in the Order Approving Partial Rate Increase that was issued in this docket on October 23, 2006, but that all other aspects of that Order shall remain final and effective;

2. That PSNC shall suspend Rate 110 effective as of June 1, 2007, and shall move all customers on Rate 110 to Rate 105 as of that date;

3. That PSNC shall create a separate deferred account as of June 1, 2007, and shall record therein the per-therm rate differentials between Rate 110 and Rate 105 and the related WNA differentials as set forth in paragraphs 6 and 7 of the Petition filed by PSNC on April 18, 2007, for a period no longer than November 1, 2007, and shall accrue interest on the deferred amounts at the Company's net-of-tax overall rate of return;

4. That PSNC shall file a petition proposing a residential rate design, accompanied by proposed rate schedules and supporting testimony, on or before July 6, 2007, and shall include with that filing a proposed public notice consistent with this order;

5. That the Commission will thereupon issue a further order providing for PSNC to publish notice of its proposed residential rate design, and PSNC shall file an affidavit of publication on or before the date of the hearing scheduled herein;

6. That interested persons shall be allowed until August 13, 2007, within which to file a petition to intervene in this proceeding, but the present parties need not file a new petition in order to participate in these further proceedings;

7. That intervenors shall have until August 13, 2007, within which to file direct testimony regarding PSNC's residential rate design proposal;

8. That rebuttal testimony may be filed on or before September 4, 2007;

9. That a public hearing is hereby scheduled for Tuesday, September 11, 2007, at 9:00 a.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, for the purpose of considering PSNC's residential rate design proposal, and the Commission will hear public witness testimony, if any, at the beginning of that hearing;

10. That post-hearing proposed orders and briefs shall be filed on or before October 1, 2007; and

11. That the Commission will undertake to issue an order on PSNC's residential rate design proposal on or before November 1, 2007.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of May, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah052107.02

DOCKET NO. G-39, SUB 10

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Cardinal Pipeline)
Company, LLC for an Adjustment) ORDER DECREASING RATES
in its Rates and Charges)

HEARD IN: Commission Hearing Room, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina, on June 26, 2007

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Robert V. Owens, Jr. and Lorinzo L. Joyner

APPEARANCES:

For Cardinal Pipeline Company, LLC:

Robert W. Kaylor, P.A., 225 Hillsborough Street, Suite 480, Raleigh, North Carolina 27603

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

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, PC, Suite 2325, Two Hannover Square, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

NATURAL GAS – RATE INCREASE

BY THE COMMISSION: On February 13, 2007, Cardinal Pipeline Company, LLC (Cardinal) gave notice pursuant to Commission Rule R1-17(a) of its intent to file a general rate case.

On February 14, 2007, Cardinal filed a Request for Waivers of certain Commission requirements pertaining to the general rate case. Specifically, Cardinal requested waivers for the requirement to file Item 25 – Accounts Payable and Item 26 – Lead/Lag Study required by Commission Form G-1, General Rate Case Requirements and of Commission Rule R1-17(b)(13)(d), regarding notice to its customers in local newspapers.

On February 19, 2007, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which the Commission granted on February 22, 2007.

On March 15, 2007, Cardinal filed its verified application for a general increase in its rates and charges (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, and the direct testimony and exhibits of Charles E. Olson, Ph.D., an economist.

On March 20, 2007, the Commission issued an Order Granting Waivers regarding Cardinal's February 14, 2007 Request for Waivers of Item 25 and Item 26 of the G-1 filing requirements and a waiver of Commission Rule R1-17(b)(13)(d), regarding notice to its customers in local newspapers.

On April 5, 2007, Piedmont Natural Gas Company, Inc. (Piedmont) filed a Petition to Intervene, which the Commission granted on April 11, 2007.

On April 10, 2007, Public Service Company of North Carolina, Inc. (PSNC) filed a Petition to Intervene, which the Commission granted on April 12, 2007.

On April 10, 2007, the Commission issued its Order Setting Investigation and Hearing, Suspending Proposed Rates, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice.

On June 5, 2007, the Public Staff filed a Motion for Extension of Time to File Testimony, which the Commission granted on June 6, 2007.

On June 13, 2007, the Public Staff filed a second Motion for Extension of Time to File Testimony, which the Commission granted on June 25, 2007.

On June 18, 2007, Cardinal, the Public Staff, Piedmont, PSNC, and CUCA filed a Joint Stipulation in settlement of all aspects of this proceeding.

On June 26, 2007, the case came on for hearing as scheduled in Raleigh. At the hearing, Cardinal, the Public Staff, and CUCA jointly presented the Stipulation to the Commission. No public witnesses appeared.

On July 16, 2007, the Public Staff, Cardinal, CUCA, PSNC, and Piedmont filed a Joint Proposed Order Approving Stipulation.

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 Public Service Company of North Carolina, Inc.; Piedmont Intrastate Pipeline Company, a wholly-owned subsidiary of Piedmont Natural Gas Company, Inc.; and TransCardinal Company, a wholly-owned subsidiary of Transcontinental Gas Pipe Line Corporation. Cardinal's principal place of business is located at the offices of its operator, Cardinal Operating Company, 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 is seeking a general increase in its rates and charges in the amount of $389,856 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 December 31, 2006.

7. The Stipulation executed by Cardinal, the Public Staff, Piedmont, PSNC, and CUCA is unopposed by any party. The Stipulation settles all matters in this docket.

8. The Stipulation provides for a decrease in annual revenues of $1,890,916.

9. The original cost of the Company'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 which 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. The Company's total annual cost of service and revenue requirement for Cardinal, as set forth in Paragraph 4 and Exhibit A of the Stipulation, are reasonable for use in this docket.

11. 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.

12. The schedule of rates shown in Exhibit B to the Stipulation is just and reasonable to all customer classes.

13. The allocation methodology employed by the 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 appropriate Allowance for Funds Used During Construction (AFUDC) rate appropriate for Cardinal, effective with the date of this order, should be 9.30%.

16. Cardinal's agreement to file its next rate case no later than five years from the effective date of rates in this proceeding and 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, is just and reasonable.

17. 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 the Company's verified Application, the testimony and exhibits of the various witnesses, the NCUC Form G-1 that was filed with the Application, the provisions of Chapter 62 of the General Statutes, 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 December 31, 2006. In its order of April 10, 2007, the Commission ordered the parties to use a test period consisting of the twelve months ended December 31, 2006, with appropriate adjustments. The Stipulation is based upon the test period ordered by the Commission, 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 by representations by Cardinal, the Public Staff, and CUCA at the hearing of this matter.

The Stipulation recites that it was filed on behalf of Cardinal, the Public Staff, Piedmont, PSNC, and CUCA. 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

These findings are supported by the Application, the direct testimony of Company witness Hutson, and the Stipulation.

Hutson Exhibit 8 indicates that the Company filed for a revenue increase of $389,856. 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 $13,632,704, which represents a $1,890,916 decrease from the total annual cost of service and revenue requirement as of December 31, 2006, 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 $69,972,268, consisting of gas plant-in-service of $107,368,659 and working capital of $311,356, reduced by accumulated depreciation of $22,479,917 and accumulated deferred income taxes of $15,227,830, is the result of negotiations among the parties and is not opposed by any party. The Commission has carefully reviewed the above amounts and concludes that they are 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 are set forth in Paragraph 4 and Exhibit A to the Stipulation. The amounts shown on Exhibit A to the Stipulation are the result of negotiations among the parties and are not opposed by any party. The Commission has carefully reviewed these amounts and concludes that they are reasonable and appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

Cardinal's reasonable operating expenses, including actual investment currently consumed through reasonable actual depreciation, is set forth in Exhibit A to the Stipulation. The amounts shown on Exhibit A to the Stipulation are the result of negotiations among the parties and are not opposed by any party. The Commission has carefully reviewed these amounts and concludes that they are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The rates reflected on Exhibit B to the Stipulation are the result of negotiations among all of the parties to this proceeding and are not opposed by any party. The Commission has carefully reviewed these rates and concludes that they are just and reasonable to all customer classes.

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

These findings are supported in Paragraph 3 and Exhibit A to the Stipulation. The stipulating parties agree to the allocation methodology employed by the Company 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 to the Stipulation, which are the result of negotiations among the parties. No party opposes these findings. The Commission has carefully reviewed these amounts and concludes that they are appropriate for use in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The support for this finding is contained in Paragraph 5 of the Stipulation. The stipulating parties further agree that the appropriate AFUDC rate for Cardinal, effective with the date of this order, should be 9.30%. No party objects to this proposal.

The Commission has carefully reviewed this proposal and concludes that the agreed-upon AFUDC rate is just and reasonable and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

Consistent with Paragraph 6 of the Stipulation, Cardinal agrees to file its next rate case no later than five years from the effective date of rates in this proceeding. 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 settlement, the Public Staff, Piedmont, PSNC, and CUCA agree not to initiate a show cause proceeding for Cardinal before its next rate case filing date. These findings are not contested by any party.

The Commission has carefully reviewed this proposal and concludes that it is just and reasonable in this docket and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

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 a reasonable opportunity to earn a fair return if it operates prudently, 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.

NATURAL GAS – RATE INCREASE

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 September 1, 2007, and the Stipulation is approved;

2. That Cardinal shall file rates to comply with ordering Paragraph 1 of this order within ten days from the date of this order; and

3. That Cardinal shall file its next general rate case no later than five years from the effective date of rates in this docket 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 17th day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah081607.05

DOCKET NO. G-9, SUB 542

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	)	ORDER ON ANNUAL
G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	)	REVIEW OF GAS COSTS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, October 2, 2007, at 9:00 a.m.

BEFORE: Chairman Edward S. Finley, Jr., Presiding, and Commissioners Lorinzo L. Joyner and William T. Culpepper, III

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 Denning Szafran, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On August 1, 2007, 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 Keith P. Maust, Managing Director, Gas Supply and Scheduling; the direct testimony of David R. Carpenter, Managing Director, Regulatory Affairs; and the direct testimony and exhibits of Robert L. Thornton, Manager of Gas 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, 2007.

On August 8, 2007, 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, 2007, set prefiled testimony dates, and required the Company to give notice to its customers of the hearing on this matter.

On August 16, 2007, Carolina Utilities Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by the Commission on August 20, 2007.

On August 28, 2007, the Attorney General filed a notice of intervention.

On September 13, 2007, the Company filed the revised direct testimony and exhibits of Robert L. Thornton. In conjunction with this filing, and with the consent of the Public Staff, the Attorney General, and CUCA, Piedmont requested that the dates for intervenor and rebuttal testimony be extended. Piedmont also requested that intervenors be provided with the opportunity to take discovery on witness Thornton's revised testimony and exhibits. No change to the October 2, 2007 hearing date was requested. On September, 14, 2007, the Commission issued its Order Allowing Extensions of Time, granting the requested extensions of time.

On September 25, 2007, the Public Staff filed the direct testimony of James G. Hoard, Assistant Director, Accounting Division; the direct testimony of Thomas W. Farmer, Jr., Director, Economic Research Division; and the direct testimony of Jan A. Larsen, Public Utilities Engineer, Natural Gas Division.

On September 27, 2007, the Company filed its affidavit of publication.

On September 28, 2007, the Company filed the rebuttal testimony of David R. Carpenter and Robert L. Thornton.

No other party filed testimony.

On October 2, 2007, the matter came on for hearing as scheduled and all prefiled testimony and exhibits were admitted into evidence. Company witnesses David R. Carpenter, Keith P. Maust, and Franklin H. Yoho, Senior Vice President of Operations, testified at the hearing. No public witnesses appeared at the hearing.

On October 16, 2007, the Company filed a letter responding to Commission questions regarding the Hardy Storage project and the Company's subscription to service from that project.

On November 5, 2007, the Company and the Public Staff filed a Joint Proposed Order.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1.. The Company is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. The Company is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. The Company has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k).

4. The review period in this proceeding is the 12 months ended May 31, 2007.

5. After making the adjustments recommended by Public Staff witness Hoard and agreed to by Company witness Thornton, the Company's gas costs and deferred account balances for the review period are properly stated.

6. During the period of review, the Company incurred total gas costs of $642,657,493.

7. At May 31, 2007, the Company had a debit balance of ($16,125,589) in its Sales Customers' Only Deferred Account and a credit balance of $15,533,072 in its All Customers' Deferred Account.

8. Piedmont operated a gas cost hedging program on behalf of customers during the applicable review period. Piedmont's hedging activities during the review period were reasonable and prudent.

9. At May 31, 2007, the Company had a debit balance of ($14,139,080) in its Hedging Deferred Account.

10. It is appropriate for the Company to transfer the ($14,139,080) 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 debit balance of ($30,264,669).

11. At May 31, 2007, the Company had a credit balance of $43,985 in its NCUC Legal Fund Account.

12. The Company has implemented changes that address several of the gas cost accounting issues enumerated by the Commission in its Orders issued in Docket No. G-9, Sub 528, Piedmont's last annual review proceeding.

13. The Company has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to the Company's system and long term supply contracts with producers, marketers, and other suppliers.

14. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: the price of gas, the security of the gas supply, the flexibility of the gas supply, gas deliverability, and supplier relations.

15. The Company's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

16. The Company should be permitted to recover 100 percent of its prudently incurred gas costs.

17. The Company should implement the temporary increments and decrements recommended by Public Staff witness Larsen as a result of this proceeding.

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 Maust, Thornton, and Carpenter. These findings are essentially informational, procedural, or jurisdictional in nature and are based on uncontested evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-7

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter, Thornton, and Maust, the rebuttal testimony of Company witness Thornton; the testimony of Public Staff witnesses Hoard, Larsen, and Farmer; and the Commission's Rules.

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, 2007, 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, work papers, 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 the Commission Rule R1-17(k)(6)(c). Witness Thornton included the annual data required by Commission Rule R1-17(k)(6)(c) as Revised Exhibit RLT-1 to his revised direct testimony. Company witness Thornton states that Piedmont incurred gas costs of $642,657,493 during the review period. Public Staff witness Hoard stated in his direct testimony that Company witness Thornton's Revised Exhibit RLT-1 properly reflects the amount of gas costs incurred by the Company during the review period and the Company's deferred account balances as of May 31, 2007, with the exception of the Hedging Deferred Account.

Public Staff witness Hoard testified that as of May 31, 2007, the Company had a debit balance of ($16,125,589) in its Sales Customers' Only Deferred Account and a credit balance of $15,533,072 in its All Customers' Deferred Account.

Company witness Thornton, in rebuttal testimony, stated that Piedmont agrees with Public Staff witness Hoard's May 31, 2007 deferred account balances.

No other party presented evidence on these issues.

The Commission concludes that the Company has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k). Based on this evidence, the Commission concludes that the

Company incurred $642,657,493 of gas costs during the review period ended May 31, 2007. In addition, the Commission concludes that the appropriate balances of the Company's deferred accounts as of May 31, 2007, are a debit balance of ($16,125,589) in its Sales Customers' Only Deferred Account and a credit balance of $15,533,072 in its All Customers' Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-10

The evidence supporting these findings of fact is contained in the direct testimony of Company witnesses Maust and Thornton, the rebuttal testimony of Company witness Thornton, Company witness Maust's responses to Commission questions, and the testimony of Public Staff witnesses Farmer and Hoard.

Company witness Thornton stated in his revised direct testimony that the Company had a total debit balance of ($14,126,606) in its Hedging Deferred Account at May 31, 2007. Public Staff witness Hoard testified that the Company's Hedging Deferred Account should be a debit balance of ($14,139,080). Witness Thornton stated in his rebuttal testimony that the Company had no objections to Public Staff witness Hoard's end-of-period Hedging Deferred Account Balance. Witness Thornton further testified that the difference was attributable to a slight variation in the method by which the Company calculated interest on the account compared to the manner in which the Public Staff performed the same function. Company witness Thornton testified that the Company is in agreement with the Hedging Deferred Account balance as calculated by the Public Staff.

In his direct prefiled testimony, Company witness Maust indicated that the Company implemented hedges for the benefit of its customers during the review period consistent with the guidelines of the Company's established Hedging Program filed with the Commission. Public Staff witness Farmer testified that he reviewed the Company's testimony and exhibits, data request responses, and various related reports. Witness Farmer further testified that Piedmont's hedging activities for the review period were reasonable and prudent and that the net debit in the Hedging Deferred Account of ($14,139,080) should be recovered from ratepayers. Witness Farmer recommended that the Company continue to evaluate its Hedging Program and implement improvements as feasible and continue the dialog regarding hedging activities and Hedging Program changes with the Public Staff and the Commission.

In response to questions from the Commission, Company witness Maust summarized Piedmont's Hedging Program. Witness Maust testified that Piedmont hedges anywhere from 30 to 60 percent of its normalized sales volumes on an annual basis and that those hedging volumes are dictated by the current market prices and the NYMEX trading prices. He testified that the Hedging Program is based upon four years of historical pricing data on the NYMEX. These four years of historical pricing data are broken down into winter and summer pricing levels and then further broken down into the ten decile levels - 100, 90, 80, 70, etc. The Company begins to hedge for price at or below the 50 decile level. Company witness Maust further testified that this four-year historical period included high prices resulting from Hurricanes Katrina and Rita. When asked by the Commission if outliers like these should be removed from historical period data, witness Maust testified that while Katrina and Rita prices might be outliers, they can happen again and are, therefore, worthy of inclusion in the historical period data. He further testified that the market reacts to hurricane forecasts and that projected hurricane activities, by some of the forecasters, certainly is reflected in the costs.

No other party presented evidence on the Company's review period Hedging Program or its operations thereunder.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent and that the Company's Hedging Deferred Account debit balance of ($14,139,080) as of May 31, 2007, should be transferred to the Company's Sales Customers' Only Deferred Account. The combined balance for the Company's Hedging and Sales Customers' Only Deferred Accounts is a debit balance of ($30,264,669).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Hoard.

Public Staff witness Hoard testified that the appropriate balance for the NCUC Legal Fund at May 31, 2007 is a credit balance of $43,985. No other party offered evidence on this matter.

Based on the foregoing, the Commission concludes that the proper balance of the NCUC Legal Fund, as of May 31, 2007, is $43,985.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is contained in Company witness Carpenter's direct and rebuttal testimony, witness Carpenter's responses to Commission questions, and the testimony of Public Staff witness Hoard.

Public Staff witness Hoard testified that in the Commission's August 1, 2007 Order on Annual Review of Gas Costs issued in Docket No. G-9, Sub 528 (Order), as corrected by an Errata Order issued on August 15, 2007, the Commission found that the Company had significant deficiencies and shortcomings in its gas accounting practices. Because of the extensive investigation of the gas accounting issues required in the Company's last annual review, the procedural schedule was extended and, ultimately, the Commission issued the Order for that proceeding on the same day that the Company filed its testimony in the current annual review. Consequently, only a small period of time has passed since the last annual review proceeding concluded. Nonetheless, during that period the Company has implemented changes that address several of the matters enumerated by the Commission in the Order.

Ordering Paragraph 4 of the Order stated that the Company shall file a proposal in a separate docket not later than sixty days after the date of the Order to address the appropriate disposition of the supplier refunds held in escrow accounts. Public Staff witness Hoard stated in his prefiled testimony that the Company had not yet filed its proposal regarding the disposition of the supplier refunds that it is holding in escrow accounts. Witness Hoard further stated that it was his understanding that the Company intended to file its proposal by September 30, 2007, the due date established in the Order.

Company witness Carpenter, in prefiled rebuttal testimony, testified that the Company is in full compliance with the Commission's Ordering Paragraph 4 of the Order. At the hearing, Company witness Carpenter testified that the Company had filed a petition with the Commission requesting that the supplier refunds be deposited into the deferred accounts for the benefit of all customers and that the disposition of the supplier refunds would be addressed in that separate docket.

Ordering Paragraph 5 of the Order stated that the Company should file timely reports of supplier refunds, which shall be due within one week following the receipt of the refund. Public Staff witness Hoard testified that the Company filed reports of supplier refunds in Docket No. G-100, Sub 57 on April 27, May 4, and August 13 of the current year. He further testified that these reports appear to be timely, accurate, and complete reports of supplier refunds that have been received by the Company.

Company witness Carpenter testified that the Company is in compliance with the Order in regards to Ordering Paragraph 5. Witness Carpenter testified that upon receiving the Order, the Company implemented all the necessary procedures to comply therewith and is now complying with the Order precisely.

Ordering Paragraph 6 of the Order stated that the Company should invest the supplier refunds held in escrow accounts in interest-bearing accounts. Public Staff witness Hoard testified that, as evidenced by the filings in Docket No. G-100, Sub 57, the Company had invested the supplier refunds that it had received since April 13, 2007, in interest-bearing accounts. The Company had also invested the $1,681,122 escrow account balance established in the Order in certificates of deposit.

Company witness Carpenter testified that the Company is now in compliance with the Order regarding the investment of supplier refunds held in escrow accounts into interest-bearing accounts. During Commission inquiries at the hearing, witness Carpenter testified that everything related to supplier refunds had been placed in the proper account and been invested in interest-bearing certificates of deposits as ordered by the Commission.

Ordering Paragraph 7 of the Order stated that the Company shall discontinue its accounting practice whereby it capitalizes storage demand charges, effective no later than November 1, 2007. Public Staff witness Hoard testified that the Company is scheduled to discontinue the accounting practice whereby it capitalizes demand and storage charges during the seven-month summer season and amortizes them during the five-month winter season, effective November 1, 2007.

Company witness Carpenter testified that the Company has ceased the process of capitalizing demand and storage charges and is in the process of making the adjustments necessary to take the impact of the current fiscal year. He further testified that ceasing this process would have a significant impact to the 2007 financial year, due to the timing of how the process works and the timing of Piedmont's fiscal year. Witness Carpenter testified that Piedmont would show about a $4 million before-tax impact on income during the fiscal year 2007 related to ceasing demand capitalization. Witness Carpenter further testified that, as ordered, the Company has ceased the process and is in the process of adjusting balances that were previously put into inventory. Witness Carpenter also testified that this would be done in the current fiscal period as ordered by the Commission.

Ordering Paragraph 8 of the Order stated that the Company shall change its accounting practices for secondary market transactions such that its accounting records will reflect the revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts, effective no later than November 1, 2007. Public Staff witness Hoard testified that the Company is scheduled to change its accounting practices for secondary market transactions, effective November 1, 2007, so that the revenues and costs for these transactions are recorded in a series of non-utility accounts, as ordered by the Commission.

Company witness Carpenter testified that effective November 1, 2007, the Company would have separate accounts for secondary market transactions in place as ordered by the Commission and that the transactions would be separated out so that they are clearly and easily identifiable.

Ordering Paragraph 9 of the Order stated that the Company should file a report that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing the changes within 90 days of the Order. Public Staff witness Hoard testified that Company personnel, along with consultants from KPMG, a financial and accounting consulting firm, are currently engaged in studying and evaluating the gas accounting processes and procedures. He further stated that the required report has not yet been filed.

Company witness Carpenter testified that an explanation of all the journal entries is in progress and would be filed with Commission by the end of the month (October 31, 2007), the due date established for the item by the Commission.

Ordering Paragraph 10 of the Order stated that the Company should consult with the Public Staff to attain the accounting process improvement goals set forth in the testimony of Public Staff witness Hoard. Witness Hoard testified that the Public Staff had had some general discussions with Company personnel regarding the accounting process improvement goals. Company witness Carpenter testified during the hearing that Public Staff involvement was an ongoing process and that the Company would keep the Public Staff abreast of changes that the Company was making in its gas cost accounting and that it would seek out its counsel on the issues.

Ordering Paragraph 11 of the Order stated that the Company should file a report that details the components of the October 31, 2006 balance of Account 253.30 – Miscellaneous Deferred Credits within 90 days of this Order. Public Staff witness Hoard testified that the Company had finished a substantial amount of work on this issue, but that the project was not yet completed. Witness Hoard also testified that he expected the Company would file the required report on Account 253.30 in a timely manner.

Company witness Carpenter testified that the Company had done most of the work on the issue and that the Company just needed to finalize all the pieces and make certain that it understood all the elements involved. Witness Carpenter also gave the assurance that the Company would properly file the item by the October 31, 2007 deadline.

Ordering Paragraph 12 of the Order stated that the Company would rectify the gas cost accounting deficiencies and shortcomings addressed in that Order forthwith and that the Company should file reports in compliance with Commission requirements in an accurate manner and on a timely basis henceforth. Public Staff witness Hoard testified that Company personnel, along with the Company's consultants, are currently engaged in studying and evaluating the gas accounting processes and procedures. The Company has implemented some new processes and staffing changes, but much work still needs to be done.

In his prefiled rebuttal testimony, Company witness Carpenter testified that Piedmont had taken a comprehensive approach in regard to its gas cost accounting deficiencies. He testified that this approach involved rebuilding its gas cost accounting capabilities from the ground up utilizing new accounting personnel, systems, and processes. He further testified that the Company had the full support of upper management. Witness Carpenter testified that the Company's new personnel and consultants had put forth tremendous efforts and worked many long hours towards implementing new systems and practices. He stated that although Piedmont had a long way to go, the Company was well on its way towards obliterating the prior weaknesses. He further stated that the system implementation and redesign would be completed during the fall of 2008. At the hearing, Company witness Carpenter testified that Piedmont had staffed the gas cost accounting department to an adequate level and that, over the next twelve months, the Company would be implementing a lot of process changes that would greatly enhance the timeliness and the accuracy of everything involved with gas cost accounting at Piedmont.

No other parties offered testified or offered evidence regarding these matters.

Based on the foregoing, the Commission concludes that the Company has implemented changes that address the gas cost accounting issues enumerated by the Commission as discussed herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-16

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Maust and Yoho and Public Staff witness Larsen.

Company witness Maust testified that the Company's gas purchasing policy is best described as a "best cost" policy. This policy consists of five main components: price of gas, security of gas supply, flexibility of gas supply, gas deliverability, and supplier relations.

Witness Maust testified that all of these components are interrelated and that the Company considers and weighs each of these five factors in establishing its entire supply portfolio.

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 Piedmont's 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, and the market-based commodity prices are tied to indices published in industry trade publications. These firm contracts range in term from one year (or less) to terms extending through October 2010. Longer-term contracts typically provide for periodic reservation fee renegotiations. Some of these firm contracts are for winter service only 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.

Witness Maust described how the interrelationship of the five factors affects the Company's construction of its gas supply 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 affecting pipeline suppliers, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, attending conferences, and subscribing to industry literature.

Witness Maust testified that the Company's greatest challenge in applying its best-cost policy is in dealing with future uncertainties in a dynamic national and regional energy market. Future demand for gas is affected by economic conditions, customer conservation efforts, weather patterns, regulatory policies, and industry restructuring in the energy markets. Future availability and pricing of gas supplies is affected by overall demand, oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. Witness Maust further stated that the Company did not make any changes in its best-cost gas purchasing policies or practices during the test period.

Witness Maust also indicated that during the past year the Company has taken several additional steps to manage its costs, including actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, actively renegotiating and restructuring its supply arrangements when possible, promoting more efficient 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.

The Commission questioned Company witnesses Maust and Yoho regarding the nature of Piedmont's investment in the Hardy Storage project, whether Hardy Storage is required to "come back" to the FERC for a rate adjustment at a specified point in time, and whether levelized rates were considered for Hardy Storage. On October 16, 2007, the Company filed written responses

(Responses) to the Commission's inquiries that supplemented the testimony of witnesses Maust and Yoho. In summary, the testimony of the witnesses and the Responses indicate that Piedmont's equity investment in Hardy Storage Company, LLC is held by Piedmont Hardy, LLC, a wholly-owned subsidiary of Piedmont. Piedmont indicates that legal precedent exists proscribing come back requirements but that the FERC's certificate order requires Hardy Storage to file a cost and revenue study at the end of its first three years of operation. Piedmont's Responses state that the cost and revenue study, "...will permit the FERC to exercise its show cause authority under Section 5 of the Natural Gas Act to adjust Hardy's rates if it deems them to be unjust and unreasonable at the end of three years of operation." Under Section 5, the FERC would bear the burden of proof. Therefore the Commission urges Piedmont to monitor Hardy's operations carefully to protect the interests of Piedmont's customers, irrespective of actions FERC takes.

Further, the Responses state that, "The possible use of levelized rates was raised early in the project discussions by potential customers but Hardy indicated that it was not interested in pursuing levelized rates...." This response fails to clarify whether Piedmont Natural Gas was one of the customers discussing levelized rates. Given that levelized rates reduce revenue up front, it seems reasonable that a party is only likely to request levelized rates if its potential customers demand them. Piedmont's Responses do not explain why the customers did not pursue this option.

The record in this docket does not support a conclusion that Piedmont acted imprudently with regard to its decision to become a customer of Hardy. The Commission urges Piedmont to review carefully Hardy's cost and revenue study when filed, as the Commission intends to do.

Public Staff witness Larsen testified that he had reviewed the testimony and exhibits of the Company's witnesses, monthly operating reports, 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.

No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were prudent and that its gas costs during the review period were prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

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 rebuttal testimony that the Company proposed to place temporary rate elements in rates to adjust amounts held in its deferred accounts.

Public Staff witness Larsen testified that he had reviewed the temporary rate decrements applicable to the All Customers' Deferred Account balance proposed by Company witness Thornton, as reflected in Exhibit RTL-3, and agreed with the calculations. Public Staff witness Larsen recommended that the proposed decrements be implemented.

Regarding the increment for sales customers, Public Staff witness Larsen testified that he calculated a temporary increment of $.03844/therm, as compared to the $0.03842/therm increment proposed by witness Thornton. This increment, which witness Larsen recommended, is calculated by dividing the $30,264,669 combined balance of the Sales Customers' Only and Hedging Deferred Accounts recommended by Public Staff witness Hoard, by the sales volume of 787,407,400 therms from Piedmont's last general rate case. Witness Larsen testified that the increment he recommended differed from that proposed by the Company because the Public Staff determined a different balance than the Company for the Hedging Deferred Account.

Public Staff witness Larsen recommended that Piedmont remove all temporary rates that were implemented in Docket No. G-9, Sub 528, while simultaneously implementing the decrements for the All Customers' Deferred Account proposed in Company witness Thornton's Exhibit RLT-3 as well as the $0.03844/therm increment he calculated for all sales rate schedules.

Company witness Thornton, in his rebuttal testimony, agreed with Public Staff witness Larsen's calculations of the temporary increment for the Sales Customers' Only Deferred Account and the temporary decrements to the All Customers' Deferred Account.

No other party presented evidence on this issue.

Based on the foregoing, the Commission concludes that it is appropriate for the Company to remove all temporary rates that were implemented in Docket No. G-9, Sub 528, and implement the temporary decrements recommended by Public Staff witness Larsen and agreed to by Company witness Thornton.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2007, under review in this proceeding, as adjusted by the Public Staff, is approved;

2. That the Company is authorized to recover 100 percent of its gas costs incurred during the period of review covered in this proceeding; and

3. That the Company shall remove all temporary rates that were implemented in Docket No. G-9, Sub 528, implement the temporary rate decrements to refund the All Customers' Deferred Account balance found appropriate herein, and implement a temporary increment of $.03844/therm for all sales customers, effective for service rendered on and after December 1, 2007.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of November, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG111907.01

DOCKET NO. G-41, SUB 23

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Toccoa Natural Gas 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: Wednesday, November 7, 2007, at 9:00 A.M, in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

BEFORE: Commissioners William T. Culpepper, III, Presiding, James Y. Kerr, II, and Howard N. Lee.

APPEARANCES:

For Toccoa Natural Gas:

Stephon J. Bowens, Blanchard, Jenkins, Miller, Lewis & Styers, P.A., 1117 Hillsborough Street, Raleigh, North Carolina 27603

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 September 4, 2007, Toccoa Natural Gas ("Toccoa" or the "Company") filed a Motion for Extension of Time to File Direct Testimony and Exhibits of its witnesses. On September 7, 2007, the Commission issued its Order Granting Motion for Extension of Time to File Direct Testimony and Exhibits. Also, on September 7, 2007, Toccoa filed the direct testimonies and exhibits of Company witnesses Rai Trippe, Member Support Business Analyst for the Municipal Gas Authority of Georgia ("Gas Authority"), and Alan Yearwood, Gas Director for the City of Toccoa, Georgia, in connection with the annual review of Toccoa's gas costs pursuant to G.S. §62-133.4(c) and Commission Rule R1-17(k)(6) for the period July 1, 2006, through June 30, 2007.

On September 13, 2007, the Commission issued its *Order Scheduling Hearing, Establishing Filing Dates and Discovery Guidelines, and Requiring Public Notice.* This Order established a hearing date of Wednesday, November 7, 2007, set testimony filing dates, and required Toccoa to give at least 30 days prior notice to its customers of the hearing on this matter.

On October 19 2007, the Company filed its Affidavits of Publication.

On October 23, 2007, the Public Staff filed the direct testimonies of David A. Poole, Staff Accountant, Accounting Division; Sami M. Salib, Public Utilities Engineer, Natural Gas Division; and Thomas W. Farmer, Jr., Director, Economic Research Division.

No other party filed testimony.

On October 31, 2007, Toccoa filed a Consent Motion for Leave to Have Annual Review Testimony Entered into the Record and its Exhibits Admitted Into Evidence ("Consent Motion").

On November 7, 2007 the matter came on for evidentiary hearing as scheduled. Presiding Commissioner Culpepper and Commissioners Kerr and Lee were present at the hearing. Pursuant to the agreement of all parties of record, the prefiled testimony and exhibits of the witnesses for the Company and the prefiled testimony of the Public Staff witnesses were introduced and admitted into evidence and the parties waived cross-examination. No public witnesses appeared to testify.

On December 17, 2007, the Public Staff and Toccoa filed a Joint Proposed Order.

On December 18, 2007, the Public Staff and Toccoa filed minor corrections to the Joint Proposed Order.

On December 19 2007, the Public Staff and Toccoa filed a Joint Second Amended Proposed Order.

Based on the testimony, exhibits, and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Toccoa is a public utility as defined in G.S. § 62-3(23), subject to the jurisdiction of this Commission.

2. Toccoa is engaged primarily in the business of transporting, distributing, and selling natural gas to customers in North Carolina and Georgia.

3. Toccoa has filed with the Commission and submitted to the Public Staff all of the information required by G.S. § 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended June 30, 2007.

5. During the period of review, Toccoa incurred total gas costs of $10,074,685, composed of $1,140,841 of demand and storage costs, $8,821,852 of commodity costs, and $111,992 of other charges/(credits). The North Carolina portion of gas costs for the review period was $548,063.

6. At June 30, 2007, the Company's North Carolina Deferred Gas Cost Account had a debit balance of ($34,905), owed from the customers to the Company.

7. Toccoa properly accounted for its gas costs during the review period.

8. Toccoa has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Toccoa's system and an "all requirements" gas supply contract with the Gas Authority.

9. Toccoa released unutilized capacity during the review period to mitigate the cost of extra demand capacity, and all of the margins earned on secondary market transactions reduced the cost of gas and flowed through to ratepayers.

10. Toccoa has adopted a "portfolio approach" gas purchasing policy consisting of four main components: long-term firm supply, short-term spot market purchases, seasonal peaking, and contract storage services.

11. Toccoa's hedging activities during the review period were prudent.

12. The Company's gas purchasing policy and practices during the review period were prudent, and its gas costs during the review period were prudently incurred.

13. The Company should be permitted to recover 100% of its prudently incurred gas costs.

14. It is reasonable to permit Toccoa to implement a temporary rate increment in the amount of $0.5729/dt for all North Carolina customers effective the first day of the month following the date of the order in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings is contained in the official files and records of the Commission and the direct testimony of Toccoa witnesses Trippe and Yearwood. These findings are essentially informational, procedural or jurisdictional in nature and are based on evidence uncontested by any of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-4

The evidence supporting these findings is contained in the direct testimony of Toccoa witnesses Trippe and Yearwood; the testimony of Public Staff witnesses Poole, Salib, and Farmer; and the Commission's Rules.

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 June 30, 2007, as the end date for the review period in this proceeding. Commission Rule R1-17(k)(6)(c) requires the filing by Toccoa of certain information and data showing weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Company witness Trippe testified that Toccoa 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). Public Staff witness Poole confirmed that the Public Staff reviewed the filings and monthly reports filed by Toccoa. No other party filed testimony or presented evidence on this matter.

The Commission, therefore, concludes that Toccoa has complied with all of the procedural requirements of G.S. § 62-133.4(c) and Commission Rule R1-17(k) for the review period.

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

The evidence supporting these findings is contained in the direct testimony of Toccoa witness Trippe and the testimony of Public Staff witness Poole.

In his prefiled testimony, Mr. Trippe testified that Toccoa's beginning balance at July 1, 2006 was ($18,690). Mr. Trippe also stated that Toccoa had maintained rates sufficient throughout the year to recover costs. He stated that the balance in the deferred account at the end of the period was ($34,905).

Public Staff witness Poole testified that the allocated North Carolina Deferred Gas Cost Account balance at June 30, 2007, was ($34,905), a debit balance, owed from the customers to the Company. He further testified that Toccoa maintains only one Deferred Gas Cost Account that includes both the commodity and demand gas charges incurred and recovered during each review period. Mr. Poole stated that in the past the Deferred Gas Cost Account was not allocated between North Carolina and Georgia because Toccoa charged the same rates in both states. He further explained that in 2005, the Public Staff and Toccoa developed a new reporting format in an effort to break out the North Carolina portion of the Deferred Gas Cost Account and began implementing increments/decrements to collect/refund its North Carolina Deferred Gas Cost Account balance from ratepayers.

In his testimony, Public Staff witness Poole testified that Toccoa has properly accounted for its gas costs during the review period.

No other party filed testimony or presented evidence on these matters.

Based on the foregoing, the monthly filings by Toccoa pursuant to Commission Rule R1-17(k)(5)(c), and the findings and conclusions set forth above, the Commission concludes that Toccoa has properly accounted for its gas costs during the review period and that the Deferred Gas Cost Account balances as proposed by the Public Staff are correct.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-13

The evidence for these findings of fact is contained in the direct testimony of Company witness Trippe and the testimony of Public Staff witnesses Poole, Salib, and Farmer.

Company witness Trippe testified that Toccoa is a charter member of the Gas Authority, which supplies its 78 member cities' needs, relying on a combination of long-term firm supply arrangements, short-term spot-market purchases, seasonal peaking, and contract storage services. He also testified that Toccoa is assured adequate, dependable, and economical gas supplies through the Gas Authority's efforts.

Public Staff witness Salib testified that he reviewed the Company's gas supply, pipeline transportation, and storage contracts. Public Staff witness Salib testified that Toccoa has eight contracts for pipeline capacity and storage service from Transco, a storage service contract with Pine Needle LNG Company, LLC, and a gas supply contract with the Gas Authority. The Gas Authority is the "all requirements" supplier for Toccoa, and as a result, the Gas Authority manages all of Toccoa's pipeline, storage service, and gas supply contracts.

Mr. Trippe further testified that the Gas Authority, on behalf of Toccoa, was able to release a portion of Toccoa's unutilized capacity each month of the fiscal period. Total dollars generated during the period of July 2006 through June 2007 totaled $148,332.

Public Staff witness Poole testified that all of the margins earned on these capacity release credits flowed through 100% to ratepayers.

Mr. Trippe stated that one of the challenges for Toccoa in the development and implementation of its gas supply strategy is in the area of price hedging. A common benchmark for comparing hedged prices is the spot market price. Mr. Trippe stated that this can be an unfair measure because it is available only after the fact, and assumes that the goal of hedging is "to beat the market." He further stated that the goal of hedging is to achieve price stability, at a reasonable level, for the consuming public.

Company witness Trippe further testified that Toccoa participates in the Gas Authority's "WinterHedge" program under the Authority's Option 2. The Gas Authority's objective in hedging is to achieve price stability at a reasonable level for the consuming public. This is accomplished by hedging up to approximately 50% of Toccoa's firm load.

Public Staff witness Farmer testified that Toccoa's hedging activities were reasonable and prudent and that the Company's net hedging costs of $27,749 incurred during this review period should be reflected in costs to ratepayers.

No other party filed testimony or presented evidence on these matters.

Based on the foregoing, the Commission concludes that Toccoa's gas purchasing policies and practices during the review period were prudent, that its hedging activities were reasonable and prudent, and that its gas costs during the review period were reasonably and prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is contained in the direct testimony of Company witness Trippe and Public Staff witness Salib.

In his testimony, Public Staff witness Salib proposed that a rate increment of $0.5729/dt be approved for all North Carolina customers, effective the first day of the month following the date of the order in this proceeding. Public Staff witness Salib further testified that this new rate increment will replace the $0.2599/dt increment that was placed in rates on February 1, 2007, as a result of Toccoa's prior annual review preceding in Docket No. G-41, Sub 21. Mr. Salib also stated that Toccoa has only one North Carolina Deferred Gas Cost Account (that includes both demand and commodity gas costs), and this will be the only temporary rate element in rates.

Toccoa agreed with the Public Staff's recommendations as indicated in its October 31, 2007, Consent Motion agreeing with the findings, positions, and recommendations set forth in the Public Staff's testimony in this proceeding.

No other party filed testimony or presented evidence on this matter.

Based on the foregoing, the Commission concludes that a temporary increment of $0.5729/dt should be implemented at this time.

IT IS, THEREFORE, ORDERED as follows:

1. That Toccoa's accounting for gas costs during the twelve months ended June 30, 2007, is approved.

2. That Toccoa is authorized to recover 100% of its gas costs incurred during the twelve months ended June 30, 2007.

3. That the Company shall remove the temporary rate increment that was implemented in Docket No. G-41, Sub 21, and implement a temporary rate increment of $0.5729/dt for all of its North Carolina customers, effective for service billed on and after February 1, 2008.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of December 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

WG122707.01

DOCKET NO. P-19, SUB 277

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Alternative Proposal for Disposition of Service Quality Penalties from 2006 and 2007	))	ORDER APPROVING ALTERNATIVE PROPOSAL

BY THE COMMISSION: On June 1, 2005, the Commission issued an order approving a modified Price Regulation Plan (Plan) for Verizon South Inc. (Verizon or Company). This revised Plan included a new self-enforcing penalty arrangement similar to those already in place for other price plan ILECs. Under this arrangement, Verizon became subject to penalties beginning July 1, 2005, for failure to meet specific Plan benchmarks for measures 5 through 14 of Rule R9-8. The benchmarks are identical to those in Rule R9-8, with the exception of the benchmark for Out-of-service troubles cleared within 24 hours.

The Plan requires Verizon to file a report with the Commission within 30 days after the end of each annual "penalty period," detailing the penalty calculations for the period and providing any other information the Company deems relevant. If the total penalty amounts to $0.25 or more per access line, the Plan calls for Verizon to issue a credit on the bill of each residence and business customer of record within 90 days of filing the report. If the penalty amount is less than $0.25 per line, the Company accumulates the penalty amounts from year to year until the $0.25 per line threshold is met or exceeded, at which point the credits are issued.

On July 28, 2006, three days before the due date for the first annual penalty report, Verizon filed a letter in this docket requesting "additional time to review some particular indices to insure the statistics on the metrics have been reported and calculated correctly." Soon after this filing, local Verizon officials contacted the Public Staff and verified that their measurement and calculation procedures were correct, and determined that the Company owed a service quality penalty for the period from July 1, 2005, through June 30, 2006. During these contacts, Verizon and the Public Staff also discussed several complaints the Public Staff had received in recent years concerning service quality issues in Verizon's western North Carolina service area and the unavailability of Digital Subscriber Line (DSL) service in that part of the state. Following these discussions, Verizon expressed interest in developing an alternative proposal that would apply the 2006 penalty amount toward the implementation of DSL service in several western North Carolina exchanges.

On October 11, 2006, Verizon filed its 2006 penalty report, which included a summary of its statewide service quality statistics over the course of the penalty period (July 1, 2005 – June 30, 2006); a detailed description of how Verizon calculated the 2006 service penalty amount; and an explanation of how Verizon planned to rectify the service quality inadequacies reflected in the report. The filing did not include any proposal for disbursing service quality penalties for 2006, either as customer credits or through any other means, but Verizon informally advised the Public Staff that such a proposal would be forthcoming.

TELECOMMUNICATIONS – MISCELLANEOUS

On July 30, 2007, Verizon filed a detailed report on its 2007 service quality results and penalty, covering the period from July 1, 2006, through June 30, 2007. Verizon amended this with a subsequent filing on August 16, 2007. On August 31, 2007, and September 7, 2007, respectively, Verizon filed confidential and redacted versions of a proposal under which it would apply the service quality penalty amounts for the 2006 and 2007 penalty periods to extending DSL service to several previously-unserved North Carolina telephone exchanges.

This matter came before the Regular Commission Conference on September 24, 2007. The Public Staff stated it had reviewed Verizon's penalty period reports, and believed that the dollar amount that each Verizon customer would receive if the 2006-2007 penalties were issued as credits would be so small that most customers would be unlikely to even notice the impact on their monthly telephone bills. Rather than issue such a miniscule credit to each North Carolina Verizon customer, the Public Staff believed that the better course would be for the Commission to allow Verizon to apply the penalty amounts for 2006 and 2007 to Verizon's proposed western North Carolina DSL expansion. In making this recommendation, the Public Staff relied heavily on Verizon's assurances that it has not allocated any 2008 capital dollars for DSL expansion into the areas identified in its August 31 proposal, and that it currently does not contemplate extending DSL to those areas prior to the end of 2009. Once these DSL projects are completed, Verizon has agreed to file a report with the Commission detailing the areas and numbers of customers to which the projects have made DSL arrangements available. Verizon should also confirm in this report that the DSL expansions were completed in accordance with the proposal filed on August 31, 2007, and that the costs incurred in extending DSL service to these new areas and customers equal or exceed the cost estimates furnished in the August 31, 2007 filing.

The Public Staff also noted that Verizon's proposal makes no mention of how the Company plans to go about improving the inadequate service performance that led to the imposition of penalties in the first place. To address this concern, Verizon has agreed to provide, by October 31, 2007, a detailed report and explanation of how it intends to rectify the service quality problems that are reflected in its August 31, 2007 filing, and to report on the effectiveness of those steps in its next annual penalty report.

Accordingly, the Public Staff recommended that the Commission issue an order (1) authorizing Verizon to utilize the 2006 and 2007 service quality penalty amounts cited on Attachment A of its August 31, 2007, filing to offset the capital costs it incurs in extending DSL service into the areas identified in Attachment B of that filing; (2) requiring Verizon to submit a report by February 27, 2008, providing details on the new areas and customers served by DSL and the costs Verizon incurred in completing the DSL expansion projects identified in its August 31, 2007, filing; and (3) requiring Verizon to provide, by October 31, 2007, a detailed report and explanation on the specific steps it intends to take to rectify the service quality problems cited in its August 31, 2007, filing, and to submit a detailed report on the effectiveness of those steps along with its 2008 annual penalty report.

Mr. Stan Pace of Verizon appeared at the Conference and responded to Commission questions. He concurred with the Public Staff's recommendation.

WHEREUPON, the Commission concludes that good cause exists to approve the alternative proposal for the disposition of self-enforcing penalty funds as proposed by the Public Staff and in accordance with the reporting requirements recommended by the Public Staff as set out above.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of October, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb102607.01

DOCKET NO. P-21, SUB 71
DOCKET NO. P-35, SUB 107
DOCKET NO. P-61, SUB 95

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Petitions of Ellerbe Telephone Company, MebTel, Inc., and Randolph Telephone Company for Arbitration with ALLTEL Communications and Cingular) RECOMMENDED ARBITRATION ORDER

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, April 23, 2007, at 1:30 p.m. and on Tuesday, April 24, 2007, at 9:00 a.m.

BEFORE: Commissioner William T. Culpepper, III, Presiding, and Chairman Edward S. Finley, Jr., and Commissioner Robert V. Owens, Jr.

APPEARANCES:

FOR ELLERBE TELEPHONE COMPANY, MEBTEL, INC., AND RANDOLPH TELEPHONE COMPANY:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

FOR ALLTEL COMMUNICATIONS, INC.:

Sean R. Simpson, 2000 Technology Drive, Mankato, Minnesota 56001
William R. Pittman, The Pittman Law Firm, 1312 Annapolis Drive, Suite 200, Raleigh, North Carolina 27608

FOR CINGULAR WIRELESS:

Paul Walters, Walters & Walters, 15E 1ST Street, Edmond, Oklahoma 73034

M. Gray Styers, Jr., Blanchard, Miller, Lewis & Styers, 1117 Hillsborough Street, Raleigh, North Carolina 27603

Mark Ashby, Cingular Wireless & AT&T Mobility, 5565 Glenridge Connector, Atlanta, Georgia 30342

FOR THE USING AND CONSUMING PUBLIC:

Kendrick C. Fentress and Ralph J. Daigneault, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: This arbitration proceeding is pending before the North Carolina Utilities Commission pursuant to Sections 251 and 252 of the Telecommunications Act of 1996 (TA96 or the Act) and North Carolina General Statute 62-110(f1).

Section 251 of TA96 requires each incumbent local exchange company (ILEC) to provide interconnection to requesting telecommunications carriers with the ILEC's network and unbundled access to network elements on rates, terms, and conditions that are just, reasonable, and nondiscriminatory in accordance with the terms and conditions of the interconnection agreement, Section 251, and Section 252 of the Act. Section 252(b) provides for the arbitration by state regulatory commissions of unresolved issues between ILECs and requesting carriers concerning agreements for interconnection and network elements.

On September 15, 2006, Ellerbe Telephone Company (Ellerbe), MebTel, Inc. (MebTel), and Randolph Telephone Company (Randolph) (jointly the rural local exchange companies (RLECs)) each individually filed a Petition for Arbitration of an Interconnection Agreement with ALLTEL Communications, Inc. (ALLTEL), New Cingular Wireless, LLC, d/b/a Cingular Wireless (Cingular), Sprint Spectrum LP, as an agent for SprintCom, Inc., d/b/a Sprint PCS (Sprint PCS), and SunCom Wireless Operating Company, LLC (SunCom) (collectively the Commercial Mobile Radio Service (CMRS) Providers) requesting the Commission to arbitrate certain unresolved issues arising out of the interconnection agreement negotiations between the RLECs and the CMRS Providers. The RLECs submitted prefiled testimony with their Petitions for Arbitration (witness Long for Ellerbe, witness Skrivan for Mebtel, and witness Thaxton for Randolph). Each of the RLECs raised substantially identical issues in their Petitions for Arbitration.

On October 4, 2006, the Commission issued an *Order on Procedure* consolidating the dockets, scheduling an evidentiary hearing for Monday, March 12, 2007, and establishing other procedural and discovery deadlines. The Commission requested that the Public Staff of the North Carolina Utilities Commission (the Public Staff) participate as an intervenor in the dockets.

TELECOMMUNICATIONS – MISCELLANEOUS

On October 9, 2006, the parties filed a letter to advise the Commission that the RLECs and Sprint PCS reached an agreement in principle that resolved the RLECs' Petitions and that the RLECs and Sprint PCS expected to file the parties' negotiated interconnection agreement with the Commission in the near future.

On October 10, 2006, the CMRS Providers filed Responses to the Petitions for Arbitration.

On October 25, 2006, Cingular prefiled the direct testimony and exhibits of William H. Brown, and ALLTEL prefiled the direct testimony and exhibits of Charles B. Cleary and Ron Williams. On November 8, 2006, Randolph prefiled the direct testimony and exhibits of Robert C. Schoonmaker, MebTel prefiled the direct testimony and exhibits of Michael T. Skrivan, and Ellerbe prefiled the direct testimony and exhibits of Herbert Long.

On December 1, 2006, the RLECs filed a Motion to Reschedule Hearing.

On December 5, 2006, the Commission issued an Order granting the RLECs' Motion, thereby rescheduling the evidentiary hearing to begin on Monday, April 23, 2007, at 1:30 p.m. in Commission Hearing Room 2115.

On January 26, 2007, the parties filed a Consent Motion to Amend Order on Procedure. On January 29, 2007, in response to the Consent Motion, the Commission issued an *Order Rescheduling Certain Procedural Deadlines*, but did not reschedule the evidentiary hearing, as requested by the RLECs and the CMRS Providers in their Consent Motion.

On February 23, 2007, Randolph filed a copy of revised confidential exhibits which were attached to Randolph witness Schoonmaker's prefiled direct testimony.

On February 28, 2007, ALLTEL and Cingular prefiled the direct testimony and exhibits of W. Craig Conwell, including confidential direct testimony.

On March 6, 2007, the parties filed a Consent Motion to Amend Order on Procedure. On March 7, 2007, the parties filed an Amendment to their Consent Motion. Also on March 7, 2007, in response to the Consent Motion, the Commission issued an *Order Rescheduling the Deadline for Submission of the Joint Issues Matrix* from March 7, 2007 until April 12, 2007.

On March 27, 2007, the parties filed a Notice of Dismissal of Arbitration Petitions as to Sprint PCS. The parties noted that each RLEC had entered into a negotiated interconnection agreement with Sprint PCS. On March 29, 2007, the Commission issued an *Order Allowing Dismissal of Arbitration Petitions as to Sprint PCS.*

Also, on March 29, 2007, the parties filed a Consent Motion to Reschedule Certain Procedural Deadlines concerning discovery, rebuttal testimony, and the joint issues matrix. On March 30, 2007, in response to the Consent Motion, the Commission issued an *Order Rescheduling Certain Procedural Deadlines*.

On April 2, 2007, the parties filed a Notice of Dismissal of Arbitration Petitions as to SunCom. The parties noted that each RLEC had entered into a negotiated interconnection agreement with SunCom. On April 4, 2007 the Commission issued an *Order Allowing Dismissal of Arbitration Petitions as to SunCom.*

On April 11, 2007, the RLECs prefiled the rebuttal testimony and exhibits of Jean Thaxton, Herbert Long, Michael T. Skrivan, and Robert Schoonmaker.

On April 16, 2007, the parties collectively filed the Joint Issues Matrix outlining the open issues in these arbitration dockets.

On April 17, 2007, the RLECs filed a Motion to Strike Portions of the Testimony of the CMRS Providers witness Craig Conwell on the grounds that said testimony is incompetent, inadmissible hearsay, not based on the witness's personal knowledge, and not properly offered as evidence in this proceeding.

On April 19, 2007, the Commission issued an *Order Regarding Redacted Filings.* The Commission directed all parties to examine the filings made in the dockets marked as confidential and submit redacted copies of the same by April 23, 2007.

On April 20, 2007, Cingular filed a Response to Motion to Strike Portions of the Testimony of the CMRS Providers witness Craig Conwell.

An evidentiary hearing was held on Monday, April 23, 2007 and Tuesday, April 24, 2007 in Raleigh. At the hearing, the Commission first sought to determine what issues remained open for arbitration. Counsel for the RLECs and the CMRS Providers agreed that with regard to ALLTEL, only Issue Nos. 6 and 17 through 30 remained open and with regard to Cingular, only Issue Nos. 1, 4, 5, 6, 8, and 17 through 26 remained open.

Cingular and Ellerbe have also resolved the following cost/rate issues: Issue Nos. 6 and 32, plus all other generic cost/rate issues (Issue Nos. 6A, 27, 28, and 29) that would otherwise be applicable to Ellerbe. All cost/rate issues remain open as between Cingular and both Randolph and MebTel.

At the beginning of the evidentiary hearing, the parties stated that they had reached a Stipulation in response to the Commission's April 19, 2007 *Order Regarding Redacted Filings.* The parties noted at the hearing that they had stipulated, as follows:

(1) that all data and information contained in exhibits to the testimony of any witness filed under seal will remain confidential, except that the parties waive all claims of confidentiality for purposes of the conducting of the hearing, including the use of any such data or information in opening statements, direct examination, cross-examination, redirect examination, or with regard to questions from or answers to the Commission, and for purposes of the preparation of the transcript in the hearings and for the purposes of the Commission's deliberations and rending of

its orders in these dockets, including any citation to any data for information in any confidential exhibit in the Commission's orders;

(2) that all data and information contained in exhibits filed by any party and labeled as confidential could likewise be set forth, referred to or otherwise used by the Public Staff in any proposed order or the Commission in any orders issued in these dockets;

(3) that, except for these permitted usages, the exhibits labeled as confidential shall continue to be labeled as confidential and will remain exempt from public disclosure pursuant to N.C.G.S. Section 132-1.2; and

(4) that the CMRS Providers waive any claim of confidentiality as to the prefiled testimony of Craig Conwell, and that the exhibits to witness Conwell's testimony shall be subject to the other provisions of the stipulation.

The Stipulation was accepted by the Commission.

Also, the Commission orally denied the RLECs' April 17, 2007 Motion to Strike Portions of the Testimony of the CMRS Providers witness Craig Conwell.

On April 30, 2007, an amended copy of Exhibit WCC-8 (an exhibit attached to the CMRS Providers witness Conwell's prefiled direct testimony) was filed.

After two Motions for Extensions of Time were granted by the Commission, on July 2, 2007, the parties filed their Proposed Orders and Post-Hearing Briefs. The RLECs and the CMRS Providers filed both Proposed Orders and Post-Hearing Briefs. The Public Staff filed a Proposed Order in these dockets.

Also, on July 2, 2007, the RLECs and ALLTEL filed a Stipulation as to Terms on Which Arbitration Issues Were Resolved with ALLTEL, which resolved all issues except for the issues relating to the appropriate reciprocal compensation rate to be paid by the parties.

On July 13, 2007, the CMRS Providers filed a Motion to Supplement Post-Hearing Brief regarding the Public Staff's Conwell Cross-Examination Exhibit No. 1 presented at the hearing. On July 25, 2007, the Public Staff and the RLECs filed responses in opposition to the CMRS Providers' Motion. On July 30, 2007, the Commission issued its *Order Denying Motion to Supplement Brief.*

The Commission notes that these Arbitration Petitions are somewhat unique in that an Order was issued in Docket No. P-100, Sub 159[1] prior to the filing of the Petitions which granted the Rural ICOs' (independent telephone companies') Petition pursuant to Section 251(f)(2) of TA96 for modification of the reciprocal compensation requirements of Section 251(b)(5) – specifically, that the Rural ICOs should not be required to perform total element long-run

[1] *Order Granting Modification Under Section 251(f)(2)* issued in Docket No. P-100, Sub 159 on March 8, 2006, hereinafter referenced as the *Modification Order.*

incremental cost (TELRIC) studies to establish reciprocal compensation rates (including the interim rate) – because: (1) the Rural ICOs are local exchange carriers "with fewer than 2% of the Nation's subscriber lines installed in the aggregate nationwide"; (2) such TELRIC studies would be unduly economically burdensome to them; and (3) the granting of such relief would be consistent with the public interest, convenience, and necessity.

FOREWORD

This arbitration is the first time that the Commission has arbitrated an interconnection dispute between CMRS providers and RLECs in which the RLECs have received an exemption under Section 251(f)(2) modifying their responsibilities under Section 251(b) of TA96. More specifically, this arbitration in large measure revolves around the establishment of appropriate rates for reciprocal compensation based upon cost studies that were to be conducted pursuant to Guidelines proposed by the Public Staff rather than reciprocal compensation rates that are TELRIC based. The RLECs acceded to these Guidelines, and they were adopted by the Commission in the Section 251(f)(2) proceeding in Docket No. P-100, Sub 159.

The alternative cost study Guidelines are as follows:

1. The cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic.

2. The cost data may be a surrogate of the company's cost, but should be forward looking and reflect and efficient network to the extent practicable.

3. The rates for transport and termination of traffic should be usage based.

4. The capital costs and structure should reflect the costs and structure approved by the Commission in previous decisions in Docket No. P-100, Sub 133d.

5. Depreciation should reflect the economic lives and net salvage values within the ranges established by the Federal Communications Commission (FCC).

6. The study should include a reasonable allocation of common costs to be added to direct costs.

7. The study should not include retail costs, opportunity costs, or revenues to subsidize other services.

Section 251(f)(2) allows a state commission to suspend or modify "the application of a requirement or requirements under subsection (b) or (c)" of Section 251, including

Section 251(b)(5), reciprocal compensation.[1] In Docket No. P-100, Sub 159, the RLECs did not request, nor did the Commission provide, that the RLECs be relieved of the responsibility to pay or receive reciprocal compensation. Instead the Commission ruled that the cost studies for such rates need not be conducted according to TELRIC principles, as would ordinarily be the case for non-rural companies which cannot avail themselves of the Section 251(f)(2) exemption or modification.

While it is true that Section 252(d)(2) addresses pricing standards for reciprocal compensation, and Section 252(d)(2) is not a provision directly subject to exemption or modification under Section 251(f)(2), it is also true that, in a case in which the modification granted under Section 251(f)(2) concerning a reciprocal compensation duty pertains specifically to TELRIC relief, the Section 252(d)(2)(A) pricing standards must be read in conjunction with Section 251(f)(2) modification. Section 252(d)(2)(A)(ii) in pertinent part provides that reciprocal compensation rates must be based on "a reasonable approximation of the additional costs of terminating such calls." Unlike the case of non-rural companies, our granting of the Section 251(f)(2) TELRIC modification means that, in formulating cost studies, the "additional costs" need not be based on TELRIC. Comparisons of the studies presented in these dockets by the RLECs with TELRIC studies involving non-rural ILECs may be occasionally instructive, but they are not determinative.

Given the circumstances of these dockets, the Commission is facing to a greater degree than usual questions of first impression calling for the exercise of its sound discretion. There is no pre-existing map leading infallibly to the "right" conclusion in all the issues. Rather, the Commission must apply its reasoned judgment in harmony with the principles that govern this arbitration. Indeed, the Commission recognized as much when it characterized the Public Staff's filing in Docket No. P-100, Sub 159 in support of the Guidelines set out in the *Modification Order* as follows: "The Public Staff stated that it did not believe that a study produced using the Guideline Nos. 1 through 7 above would be economically burdensome to the Rural ICOs, and it will enable the CMRS Providers and the Commission to review the study for *reasonableness*." (Emphasis added).

A glossary of the acronyms referenced in this *Order* is attached as Appendix A.

Based on the foregoing and the entire record in this matter, the Commission makes the following

[1] The economic underpinnings of Section 251(f)(1) and Section(f)(2) were that Congress recognized that it might be economically ruinous to impose the same competitive standards on RLECs as on non-rural ILECs unless great care was taken. That is why the Congress established a process whereby, as under Section 251(f)(1) certain automatic exemptions to RLECs might be removed, or, as under Section 251(f)(2), certain other exemptions or modifications might be granted. Whether these exemptions or modifications should be granted, denied, or removed was entrusted to the sound discretion of the state commissions.

TELECOMMUNICATIONS – MISCELLANEOUS

FINDINGS OF FACT

1. A CMRS Provider must choose a single Point of Interconnection (POI) on the RLEC's networks that is within the CMRS Provider's Major Trading Area (MTA) for the interconnection of the parties' networks. Each party is technically and financially responsible for transporting and delivering its originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of completing the call beyond the POI.

2. The RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI.

3. The appropriate reciprocal compensation rate is determined by applying the evidence and conclusions as set forth herein as applicable for Ellerbe, MebTel, and Randolph. The RLECs should modify their respective alternative cost studies to reflect the Commission's conclusions.

4. Because the Commission modified the reciprocal compensation requirements of Section 251(b)(5) of the Act, pursuant to Section 251(f)(2) of the Act, in Docket No. P-100, Sub 159, the RLECs are not required to perform TELRIC studies to establish reciprocal compensation rates, and the rates proposed for reciprocal compensation do not have to comply with all of the requirements set forth in Section 252(d) of the Act and the related FCC rules.

5. Cingular is to develop a 30-day originating traffic study, which is to be used in establishing a default interMTA traffic factor. The parties are encouraged to negotiate between themselves. The Public Staff is encouraged to offer its good offices to the parties to resolve this issue.

6. When an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber and that subscriber is roaming outside the MTA at the time the call is made it is an interMTA call, and the RLEC is entitled to be paid originating access by the CMRS Provider.

7. The investment in the Mebane DMS switch should be excluded from MebTel's cost study.

8. It is not appropriate to alter MebTel's proposed switch investment per line as proposed by the CMRS Providers. However, in Finding of Fact No. 7, the Commission has concluded that the parties have agreed that the investment in the Mebane DMS switch should be excluded from MebTel's cost study. Therefore, the Commission agrees that MebTel's proposed total switch investment per line of $458 should be used; however, this figure should be adjusted based on the Commission's conclusions concerning usage sensitive switching costs discussed in Finding of Fact No. 10.

9. An annual cost factor of 30.5% should be used for MebTel to compute switching annual costs per line.

10. MebTel's transport and termination rate should not recover its nonusage sensitive switching costs. Further, 38% of total switching annual costs per line should be recovered by MebTel's transport and termination rate.

11. Randolph's alternative cost study is based upon appropriate cost data and should be adopted. However, Randolph should update its alternative cost study to reflect the NECA average schedule formulas adopted for the one-year period beginning on July 1, 2007 and the most current Local Switching Support (LSS) formulae.

12. Although Randolph's alternative cost study uses embedded costs to some degree with forward-looking demand units, Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order.*

13. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23A is moot.

14. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23B is moot.

15. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23C is moot.

16. Because the Commission has concluded in Finding of Fact No. 12 that Randolph's use of these embedded costs is reasonable and appropriate and is in compliance with the Commission's *Modification Order* even though Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, Matrix Issue No. 23D is moot.

17. It is appropriate to request Randolph and the CMRS Providers jointly to review Randolph's continuing property records to attempt to agree on the appropriate Randolph-specific usage sensitive switching costs to be included in Randolph's alternative cost study.

18. Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate.

19. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25A is moot.

20. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25B is moot.

21. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25C is moot.

22. Since the Commission has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, Matrix Issue No. 25D is moot.

23. It was appropriate for Ellerbe to adopt Randolph's cost study as modified herein.

24. The alternative cost study Guidelines adopted by the Commission in Docket No. P-100, Sub 159 do not require the RLECs to use forward-looking costs in all facets of their alternative cost studies.

25. Only the traffic-sensitive costs of a switch comprise the direct costs associated with terminating local traffic and should be recouped through reciprocal compensation rate. The non-traffic sensitive component of end office switches are necessary regardless of whether local traffic is routed through the switch.

26. Only the direct costs for central office investments associated with the additional cost of terminating local traffic should be included in the RLECs' alternative cost studies - that is, the part of the switch that is considered to be traffic-sensitive and not associated with the line port.

27 - 29. In the Evidence and Conclusions for Findings of Fact Nos. 7 through 10, the Commission addressed the CMRS Providers' objections to the alternative cost study filed by MebTel. In its conclusions for these findings, the Commission indicated what adjustments or changes to the study are required to meet all the Guidelines established in Docket No. P-100, Sub 159. Once these adjustments are made, MebTel's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. Likewise, for Randolph's study, the Commission has addressed objections raised by the CMRS Providers in the Evidence and Conclusions for Findings of Fact Nos. 11 through 22. The Commission has spelled out the necessary adjustments necessary to meet the Guidelines it established in Docket No. P-100, Sub 159. Once these adjustments are made, Randolph's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. By the same token, Ellerbe should make similar adjustments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

ISSUE NO. 1 – MATRIX ISSUE NO. 1

CMRS Providers Statement: How should "Point of Interconnection" (POI) be defined?

RLECs Statement: Should Point of Interconnection be defined differently for direct traffic and for indirect traffic?

POSITIONS OF PARTIES

RLECs: The POI should not be defined differently for direct traffic and indirect traffic. The Commission correctly resolved this same issue in the CMRS-ILEC arbitration in Docket No. P-118, Sub 130. An ILEC is not required to interconnect at any location outside its network, and the ILEC's responsibility is limited to delivering traffic to a technically feasible point on its network.

CMRS PROVIDERS: In the case of directly interconnected carriers exchanging traffic, the POI is the physical point of interconnection between them. The RLECs have agreed, in Section 4.1 of the interconnection agreement, that the POI for direct interconnection shall be located at the "LEC's service territory boundary." In the case of indirectly interconnected carriers exchanging traffic, there is no POI between them. Instead, each carrier has a separate POI with the intermediary carrier.

PUBLIC STAFF: The POI should be defined as single physical, technically feasible point on the RLECs' networks, selected by the CMRS Provider, that is within the CMRS Provider's MTA for the interconnection of the Parties' networks. The CMRS Provider must choose a single POI on the RLEC's network that is within the relevant MTA for the interconnection of the Parties' networks.

DISCUSSION

The RLECs stated that the parties agree that, in the event of direct interconnection, the POI must be at a technically feasible location on the RLEC's network. For indirect traffic exchange, the RLECs maintained that Cingular seeks to define the POI, for financial purposes, as that point where the network of the third-party tandem provider interconnects with the terminating Party's network.

However, the RLECs stated that in connection with indirect exchanged traffic (i.e., traffic that passes through a third-party tandem provider – typically BellSouth/AT&T) Cingular seeks to make the RLEC responsible for the costs of transporting RLEC originated traffic outside its network, across the third-party transit provider's tandem, to the point where Cingular has chosen to interconnect with the tandem provider. Witness Thaxton testified that the RLECs disagree that the POI for indirect interconnection should be located at a tandem of a third-party transit provider. The RLECs stated that all of this is outside the RLECs local exchange area and outside the RLECs network.

The RLECs noted that the RLECs and Cingular agree that the POI for direct interconnection must be located at a technically feasible point on the RLEC's network. However, the RLECs disagree with Cingular's position regarding the POI for indirect traffic exchange. The RLECs maintained that the FCC has given the CMRS Providers and other telecommunications carriers the right to interconnect at a technically feasible point on the network of an incumbent LEC. Contrary to witness Brown's testimony, the FCC rule is that, when a carrier seeks to establish a reciprocal compensation interconnection arrangement with an incumbent LEC for the transport and termination of traffic, the point of interconnection must be on the ILEC's network.

The RLECs pointed out that 47 CFR Section 51.701(c) defines transport, for purposes of a reciprocal compensation agreement, as being "the interconnection point between two carriers" exchanging traffic. There can only be a point of interconnection between two carriers where they actually link their networks. An ILEC, a transit provider and a CMRS provider are three carriers, rather than two; and there is simply no basis for finding that an ILEC can be forced to interconnect with Cingular at a third-party tandem or any other location outside the RLEC's network.

The RLECs observed that Cingular may arrange for the provision of transport from the POI on the ILEC's network to its end office equivalent through a variety of options, including utilizing the facilities of a third-party carrier like BellSouth, and Cingular is entitled to charge the originating carrier reciprocal compensation to cover its transport and termination costs. However, Cingular does not have the option of forcing an RLEC to pay the third-party tandem provider for providing transit from the ILEC's network to some other location chosen by Cingular outside of the ILEC's network.

The RLECs stated that Cingular witness Brown sought to define the POI for the exchange of indirect traffic with the RLEC for financial responsibility purposes. Furthermore, Cingular seeks to establish a reference point to be used for allotting the cost of moving traffic between a CMRS provider and an RLEC via indirect means. Witness Brown argued that RLECs are responsible for payment of transit charges on their originating traffic – making the statement that both FCC regulations and the Act require all "Telecommunications Carriers," which includes RLECs, "to interconnect directly or indirectly with the facilities and equipment of other telecommunications carriers."

The RLECs did not dispute the requirement to interconnect directly or indirectly, but they do dispute that they can be made responsible for costs for transporting traffic or providing facilities to an interconnection point outside their network. Cingular witness Brown conceded that there is no FCC definition as to where the POI is located in the case of indirect interconnection.

The result sought here by Cingular would obligate the RLECs and their customers to bear the costs of extending delivery of traffic to any location in the MTA selected by Cingular, without regard to the RLECs existing network or service areas. The RLECs noted that Section 251(c)(2)(B) of the Act and Parts 51.701 and 51.703 make no distinction between direct and indirect connections.

The CMRS Providers' view was otherwise. The CMRS Providers believe that Matrix Issue No. 1 asks where the POI should be defined when the parties exchange traffic indirectly. The CMRS Providers noted that there is no dispute that, in cases of direct interconnection, the POI is where the direct interconnection facility of the CMRS Provider meets the direct interconnection facility of the RLEC.

The RLECs claim that, for compensation purposes, when interconnection is indirect, the POI can only be located at the spot where the RLEC network connects to the intermediary network – regardless of which party originates the call. The CMRS Providers contended that such a result means that the CMRS Provider must pay transit charge for landline-originated traffic.

The CMRS Providers' view was that Section 251(c)(2)(B) on its face applies only to direct interconnection, which must be within an incumbent LEC's network. Furthermore, the CMRS Providers stated that, in contrast, indirect interconnection is governed by Section 251(a) of the Act, which provides: "Each telecommunications carrier has the duty (1) to interconnect directly or indirectly with the facilities and equipment of other telecommunications carriers."

The CMRS Providers argued that with indirect interconnection, where the originating and terminating carriers do not share a common POI, interconnection between the CMRS Provider and the transit provider necessarily occurs outside of a rural LEC's network. The CMRS Providers concluded by saying that, in cases of indirect interconnection, there are two POIs (1) the point of interconnection between the RLEC and the tandem provider, and (2) the point of interconnection between the CMRS Provider and the tandem provider.

The Public Staff noted that, according to the RLECs, the POI should be defined as a single physical, technically feasible point on their networks, selected by the CMRS Provider that is within the CMRS Provider's MTA for the interconnection of the Parties' networks. The Public Staff pointed out that RLEC witness Thaxton argued that the FCC has given CMRS Providers and other requesting telecommunications carriers the right to interconnect at a point on the network of the ILEC. The Public Staff commented that witness Thaxton stated that a CMRS Provider requesting interconnection with an ILEC may establish interconnection at that point on the ILEC's network directly or indirectly.

The Public Staff observed that the RLECs argued that, in accordance with Section 251(c)(2)(B) of the Act, the interconnection point must be within the carrier's (RLEC) network. As further stated, when the CMRS Provider elects to utilize the facilities of a third party to establish the single relevant POI between its network and the ILEC's network, it is the business decision of the CMRS Provider only. The Public Staff does not believe that two POIs are created.

The Public Staff pointed out that Cingular assumed that, in instances of indirect interconnection, the POI should be located at a point where the network of the third party that delivers such traffic is interconnected with the terminating Party's network and that the originating Party should be responsible for the transport and termination of all traffic it originates, including any transit charges from the originating switch to the POI. The Public Staff stated that witness Brown contended that Section 251(c)(2) does not empower RLECs to unilaterally mandate that the CMRS Providers establish a POI on the RLECs' network unless the CMRS Providers have requested direct interconnection. The Public Staff noted that, citing the FCC's *Local Competition Order*, Cingular witness Brown concluded that the CMRS Provider has the option to choose whether to interconnect directly or indirectly, based upon their most efficient and economic choices. The Public Staff observed that RLEC witness Thaxton admitted that the RLECs are not forced to send traffic back to the CMRS Provider through the same third party network. The Public Staff stated that Cingular contended that the RLECs cannot require the CMRS Provider to establish a POI on their networks.

The Public Staff argued that the Commission had correctly concluded in Petition of Cello Partnership d/b/a Verizon Wireless for Arbitration with ALLTEL Carolina, Inc. (Docket No. P-118, Sub 130; *Alltel* case), that there is neither a legal nor a statutory requirement that the POI for indirect interconnection be defined differently from the POI for direct interconnection. Thus, the RLECs' position is consistent with the Commission's *Alltel* case. The Public Staff commented that Cingular contested the applicability of the *Alltel* case; however, because the Commission failed to acknowledge the factual differences between direct and indirect interconnection, which resulted in the requirement that all CMRS Providers must interconnect directly with all RLEC networks.

The Public Staff stated that the Commission had rejected Cingular's interpretation of the federal law and of the Commission's findings and conclusions in its *Alltel* case. The Commission cannot find a basis for distinguishing between direct and indirect interconnection with regard to placement of the POI. The Public Staff noted that, in the *Alltel* case, it found that for two carriers to interconnect, either directly or indirectly, they must have a POI: that is, a point at which traffic is physically exchanged between the two carriers' networks. The FCC rules provide that an RLEC shall provide interconnection with its network at any technically feasible point within the RLEC's network. The Public Staff reiterated that Cingular is free to use the facilities of a third party to reach the POI if it so chooses. The Public Staff concluded that use of a third party to indirectly connect with the RLEC, however, neither changes the POI's location nor creates a second POI to which the RLECs must provide facilities.

In summary, the Public Staff stated that Cingular must choose a POI that is located in an RLEC local exchange area, i.e., on the RLEC network. Cingular is free to choose any technically feasible point in any RLEC local exchange area in the MTA, and the RLEC will be required to transport all of its originating traffic within the MTA to the single POI chosen by Cingular. The Public Staff also argued that the RLEC must pay reciprocal compensation to Cingular to cover the cost of completing the call beyond the POI.

After careful consideration of the arguments of the parties, the Commission concludes that the *Alltel* case provides clear guidance on this issue and that, therefore, for two carriers to interconnect, either directly or indirectly, they must have a POI: i.e., a single point at which traffic is physically exchanged between the two carriers' networks. The POI, to be selected by Cingular, must be a technically feasible point within the RLEC's network at some point within Cingular's MTA. The selected POI will provide the exchange point for all traffic between the carriers, directly and indirectly. The carriers have latitude in deciding the network design most efficient to reach the POI for the interexchange of traffic.

The Commission also believes that the use of a third party to reach the POI is simply a decision to be made by Cingular in its design of the optimal network configuration to meet its forecasted traffic characteristics with the RLECs. Likewise, the RLEC will certainly have its traffic characteristics to consider in addressing the interexchange requirement with Cingular. Reasonable network design topology according to industry standards should be deployed in selecting the most efficient point of interconnection on the RLECs' networks to exchange traffic between Cingular and the RLECs. Cingular is to decide, based on its own network requirements, whether or not to incorporate the use of a third party to make connection at the designated POI.

The Commission is aware that our decision to follow the *Alltel* precedent in this case is inconsistent with the decisions reached by the Tenth Circuit Court of Appeals in *Atlas Telephone v. Oklahoma Corporation Commission,* 400 F.3d 1256(Tenth Cir. 2005)(*Atlas*) and the Commissions in Georgia, Tennessee and Florida. We have examined each of those decisions closely and are unconvinced that we should abandon the well reasoned analysis upon which the *Alltel* decision is based. We continue to believe, as did a different panel of our fellow Commission members in the *Alltel* case, that "[f]or two carriers to interconnect, either directly or indirectly, they must have a POI-that is, a point at which traffic is physically exchanged between the two carriers' networks" and that "[t]he FCC rules provide that an ILEC shall provide interconnection with its network at any technically feasible point within the ILEC's network."

In *Atlas*, the Tenth Circuit reached a much different conclusion. The Tenth Circuit held that the Telecommunications Act does not require the POI to be located at any technically feasible point within the ILEC's network when the CMRS carriers seek indirect connection with the ILEC's network. Instead, the Tenth Circuit held that there are two POIs located where each carrier connects on either side of the third party tandem respectively. The Tenth Circuit reasoned that 47 U.S.C. 251(c)(2), which provides that ILECs bear a statutory duty to provide for facilities and equipment of any requesting telecommunications carrier to interconnect with the ILEC's network and such interconnection must be "at any technical feasible point within the [ILEC's] network"[1] does not govern point of interconnection for the purposes for the indirect exchange of

[1] 47 U.S.C. 251(c)(2) states: (c) Additional obligations of incumbent local exchange carriers In addition to the duties contained in subsection (b) of this section, each incumbent local exchange carrier has the following duties:...

(2) Interconnection

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 of this title.

local exchange traffic. The Tenth Circuit reached this conclusion by analyzing the Sections in 251 of the Telecommunications Act in isolation. By analyzing Section 251 in this manner, the Tenth Circuit determined that the Act established a three tier system of obligations imposed on separate, statutorily defined telecommunications entities. Because the Act was structured in this manner, the Tenth Circuit concluded that the obligations established in 251(c)(2) which included the duty to interconnect at a technically feasible location within the ILEC's network by its terms only extended to the ILEC and is triggered only upon the request of another telecommunications carrier. Since the CMRS carriers were not requesting direct interconnection, the Tenth Circuit reasoned that the 251(c)(2) requirements were inapplicable and that the responsibilities of the ILEC and the CMRS providers were instead governed by the more general duties described in Section 251(a) which permitted either direct or indirect connection of the networks.

We find that the analysis employed by the Tenth Circuit is flawed and unpersuasive. As the *Atlas* court stated, section 251a)(1) of the Telecommunications Act does indeed describe general duties of "telecommunications carriers." It contains, however, only two sections, the first of which is "to interconnect directly or indirectly with the facilities and equipment of other telecommunications carriers." As such, it is a *general* obligation pertaining to all manner of telecommunications carriers. Section 251(c)(2) is among what are described as the "Additional Obligations of Incumbent Local Exchange Carriers." Section 251(c)(2) has four subsections ((A) through (D)), of which the most important for our purposes is the duty to interconnect "(b) at any technically feasible point *within the carrier's network.*" (Emphasis added) The crux of the Tenth Circuit's analysis is that Section 251(c)(2) applies only to the limited class consisting of ILECs while Section 251(a) applies to all telecommunications carriers. The Tenth Circuit said that it "cannot conclude that such a provision [speaking specifically of section 251(c)(2)], embracing only a limited class of obligees, can provide the governing framework for the exchange of local traffic."

In its embrace of the Section 251(a)(1) and its rejection of the general applicability of the Section 251(c)(2) responsibilities, the Tenth Circuit overlooks the fact that Section 251(a) has no operational content. It is a simple statement that telephone carriers have a duty to connect either directly or indirectly. The statement lacks, however, any directions to guide the carriers on accomplishing either a direct or indirect interconnection. This contrasts sharply with Section 251(c), which has significant operational content *along with the statement of a duty.*

The cascade of duties set out in Section 251 (first to all telecommunications carriers [251(a)], then to local exchange companies, including our CLPs [251(b)], and lastly to *incumbent* local exchange companies [251(c)] was carefully calibrated in levels of generality from the most general to the more particular. It is an axiom of legal interpretation that the particular informs the general in construing a statue. Similarly, another axiom of statutory construction provides that statutes or other parts of statutes concerning similar subject matter should be construed *in para materia* and each statute or section thereof is construed in light of, with reference to, or in connection with, other statutes or sections. In this case, since the CMRS and the ILEC are in fact interconnecting, it is not unreasonable that Section 251(c)(2), which provides the only statutory guidance on the location of the POI, should apply.[1] For these legal reasons, we decline to follow *Atlas* and continue to support the decision reached by our colleagues in *Alltel.*

In addition to the legal reasons which we have previously set forth for not adopting the *Atlas* position on this issue, the Commission is also mindful of the policy and equity implications of following the *Atlas* decision. The superficial appeal of *Atlas* from an equity point of view is that it leads to a "mirroring" of the financial responsibilities as between the RLECs and CMRS because it creates two POIs at either end of the transit link, and each party must pay the transiting costs for originated calls to the other party's POI. However, the *Atlas* outcome tends to disadvantage the RLECs because they are much smaller than the CMRS, have fewer resources, and are being subjected to costs based on the location of POIs over which it has no input or control. This contrasts with the *Alltel* outcome in which there is one POI and, pursuant to Section 251(c)(2)'s express command, it must be within the RLEC's network. In addition, under *Atlas,* the CMRS can choose to put its POI anywhere on its own network within its MTA and thus compel the RLEC to pay for the transit over great distances. This is yet another consequence that flows from the lack of operational definition in Section 251(a)(1) concerning indirect interconnection arrangements.

Without clearer direction from Congress or the FCC, we decline to adopt the result mandated by the *Atlas* analysis as it would clearly disadvantage and threaten the continued viability of the rural telecommunications carriers. In our opinion, the record is clear that Congress and the FCC intended to protect small and rural telecommunications providers from the unrestrained effects of a fully competitive market. Until we can no longer say as did the panel in *Alltel*, that "the Commission cannot find a basis for distinguishing between direct and indirect connection", we believe equity requires that we must follow the precedent established by *Alltel* that the POI must be located at a single location within the RLEC's network absent an agreement by the parties to do otherwise. In our opinion, this is the most reasonable interpretation of the applicable law, Section 251(b)(5) of TA96 and FCC Rules 51.701 and 51.703 in the absence of clearer direction from the FCC or the federal courts in the Fourth Circuit to the contrary.

CONCLUSIONS

The Commission concludes that the POI is defined as a single physical, technically feasible point on the RLEC's networks, selected by the CMRS Provider that is within the CMRS Provider's MTA, for the interconnection of the Parties' networks for the exchange of all traffic, direct and indirect.

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[1] The Tenth Circuit also founders with its argument that "[i]f Congress had intended Section 251(c)(2) to provide the sole governing means for the exchange of local traffic, it seems inconceivable that the drafters would have simultaneously incorporated a rural exemption functioning as a significant barrier to the advent of competition." This is not surprising at all. Surely, the Telecommunications Act is *generally speaking* pro-competitive but not in each particular instance. Congress thoughtfully provided for exemptions to ILECs (i.e., to the rural carriers) which it deemed needed to be provisionally protected from competition. Once again, the Tenth Circuit has difficulty distinguishing the general principle from the particular application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

ISSUE NO. 2 – MATRIX ISSUE NO. 4

CMRS Providers Statement: Is each party obligated to pay for the transit costs associated with the delivery of traffic originated on its network to the terminating party's network?

RLECs Statement: In the event of indirect interconnection, are RLECs obligated to pay any transit costs assessed by third-party carriers for transport of traffic to a CMRS provider outside the RLEC's service area and network?

POSITIONS OF PARTIES

RLECs: No. The RLECs have no responsibility for the cost of facilities or transport to locations outside their networks. The Commission correctly resolved this same issue in the CMRS – ILEC arbitration in Docket No. P-118, Sub 130, and there is no reason for the Commission to decide this differently now.

CMRS PROVIDERS: Each originating Party is required by the Act and FCC regulations to pay any transit charges imposed by a transiting carrier to deliver traffic to a terminating carrier, plus all costs of facilities linking its own switch to the third party transiting tandem. The RLECs proposed definition of transit traffic in Section 1.2.6 of the proposed Interconnection Agreement ignores this obligation.

PUBLIC STAFF: The RLECs are technically and financially responsible for transporting and delivering their own originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but are not responsible for transit charges based on use of a third party provider's network facilities. The RLECs' technical and financial responsibility for transit charges is limited to delivering traffic to its service borders.

DISCUSSION

The RLECs argued that the FCC has determined that its rules do not address third-party transit service, citing *In the Matter of Petition of WorldCom, Inc. Regarding Interconnection Disputes with Verizon Virginia Inc.*, 17 FCC Rcd. 27039, 27100 Para 115 (2002) (*WorldCom Petition*). In affirming Verizon Virginia's assessment of transit charges on competitive carriers, the FCC noted an absence of FCC rules specifically governing transit service. The RLECs argued that the FCC declined to rule that Verizon Virginia was obligated to provide transit service, noting a lack of clear Commission precedent or rules declaring such a duty. The RLECs believed that, since the FCC had declined to obligate an RBOC to provide transit service to facilitate indirect interconnection, the Commission should not now require RLECs to purchase such transit service to extend the delivery of traffic beyond their networks.

The RLECs further cited *Iowa Utilities Bd. v. F.C.C., 120 F.3d 753 (8th Cir. 1997)(Iowa Utilities Board)*, where the Eighth Circuit Court of Appeals ruled that an ILEC does not have the obligation to provide interconnection to other carriers at a level greater than it provides for itself and that there is no requirement to provide superior interconnection arrangements to requesting carriers. Furthermore, the Ninth Circuit Court of Appeals confirmed that interconnection obligations exist only with respect to an ILEC's existing network, recognizing that Sections 251 and 252 of the Act require ILECs to allow CMRS providers to interconnect with their existing networks in return for fair compensation. *U.S.West v. Washington Utilities & Tranp. Comm'n*, 255 F.3d 990, 992(9^{th} Cir. 2001).

The RLECs pointed out that 47 C.F.R. 20.11(a) does not support Cingular's position: a local exchange carrier must provide the type of interconnection reasonably requested by a mobile service licensee or carrier unless such interconnection is not technically feasible or economically reasonable. The RLECs argued that Cingular has not met the burden of establishing that a POI outside the RLEC's network is economically reasonable for a rural telephone company.

The RLECs reiterated that their position is consistent with the Commission's decision on the transit cost responsibility issue in the *Alltel* case. In resolving the transit responsibility issue in the *Alltel* case, the Commission ruled as follows:

> Verizon Wireless must choose a single POI on ALLTEL's network that is within Verizon Wireless's MTA for the interconnection of the parties' networks. Each party is technically and financially responsible for transporting and delivering its originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of completing the call beyond the POI.

The RLECs stated that, under the Commission's ruling in the *Alltel* case, Cingular remains free to continue to exchange traffic with the RLECs indirectly through a third-party tandem provider. However, if it does so, the RLECs contended that Cingular is then financially responsible for all charges on its side of the POI, just as the RLEC is responsible for all costs on its side of the POI.

Cingular observed that the RLECs claim that the POI, in the case of indirect interconnection, must always be considered to be located at a physical, technically feasible point on the ILEC's network and further that the POI is the demarcation point to establish economic responsibility of each party. The CMRS Providers argued that, for indirect interconnection, the POI should be located at a point where the network of the third party that delivers such traffic is interconnected with the terminating party's network, and further that the originating party should be responsible for the transport and termination of all traffic that it originates, including any transit charges from the originating switch to the POI.

According to Cingular, requiring the LECs to deliver traffic without charge to CMRS Providers means, in the case of indirect interconnection, RLECs must pay transit charges. Cingular pointed out that 47 C.F.R. 51.701(b)(2) of the FCC Rules requires reciprocal compensation to be paid for telecommunications traffic exchanged between a LEC and a CMRS Provider that, at the beginning of the call, originates and terminates within the same MTA. Cingular further argued that 47 C.F.R. 51.703(b) of those same rules states that a LEC may not assess charges on any other telecommunications carrier for telecommunications traffic that originates on the LEC's network. Cingular further stated that it believes that those two sections require RLECs to pay transit charges for RLEC originated traffic.

Cingular argued that the Commission's language in the *Alltel* case states that the reciprocal compensation paid by the LEC for originated traffic would cover the cost of completing the call beyond the POI. Cingular suggested that one of the costs of completing a LEC's originated call beyond the POI is the transit charge owed to the intermediary carrier.

Cingular noted that the Commission's decision in the *Alltel* case means that the LEC is responsible for all costs of completing an originated call beyond the POI between the RLEC and the transit carrier, including any transport charges that a wireless carrier would otherwise be required to pay to transport a call to a customer roaming in a distant location. Cingular stated that this point needs to be clarified.

Cingular argued that it should not be held responsible to pay for transit charges, and then have to seek reimbursement from the RLECs in the form of reciprocal compensation. Cingular maintained that, in cases of indirect interconnection, the originating LEC should pay the transit charge directly to the transit carrier.

The Public Staff aptly observed that this issue goes to the heart of one of the basic disputes in this arbitration, i.e., which party is responsible for the payment of transit costs in cases of indirect interconnection. The Public Staff noted that it was the RLECs' view that their obligations and responsibilities do not extend beyond their networks and that any charge assessed by a third party transit provider for traffic which transits its network in route to a CMRS provider is neither a charge assessed by the RLEC nor one to be paid by the RLEC.

The RLECs explained that each carrier is responsible for the facilities used to provide transport on its side of the POI. The Public Staff noted, based on the testimony of witness Thaxton, that a CMRS Provider may choose how it deploys the transport facilities (or secures transport services) on its side of the POI. When an RLEC delivers traffic to the POI, chosen by the CMRS provider on the RLEC's network for termination on a CMRS Providers' network, the RLEC connects the traffic to the third party carrier's transit facilities based on the CMRS Provider's selection of that option for the provision of transport from the POI to its end office equivalent. The Public Staff stated that the RLEC does not pay the third party carrier for the transport facilities arranged by the CMRS provider to carry the traffic between the POI and the CMRS end office equivalent.

According to the RLECs, the treatment of transport, a defined term in the FCC's reciprocal compensation rules, is distinct from the transit charges assessed by a third party carrier as a result of a CMRS Provider's decision to arrange transport from the POI to its facilities over the third party carrier's network. The Public Staff stated that the third party carrier will only assess transit charges because of the choice of the CMRS Provider to utilize the third party carrier's facilities to provide transport from the POI to the CMRS Provider's facilities.

The Public Staff asserted that, assuming reciprocal compensation traffic is involved, the originating RLEC pays the terminating CMRS provider for transport of that traffic in accordance with 47 C.F.R. 51.701(c) of the FCC Rules. Furthermore, as provided in 47 C.F.R. 51.711, the reciprocal compensation rates adopted by the Commission in this proceeding will be symmetrical. The Public Staff contended that Cingular has provided no support for any claim that its costs will differ from that which the Commission finds appropriate for the RLECs.

The Public Staff observed that Cingular argued that the originating carrier, not the terminating carrier, is responsible for transit costs. According to Cingular, when parties interconnect indirectly, the originating party is always responsible for paying the transiting cost associated with its own originated traffic, regardless of the location of the POI. Cingular witness Brown argued that Section 251(b)(5) obligates RLECs to pay for the costs associated with delivery of traffic to terminating carriers. The Public Staff argued that Cingular witness Brown incorrectly characterized the *Alltel* case as requiring all wireless carriers to establish direct interconnection trunks with all RLECs. Witness Brown contended that the Act and FCC regulations allow CMRS Providers to connect indirectly with RLECs.

The Public Staff observed that the RLECs argued that the economically advantageous choice for a CMRS provider to sit behind a third party provider's tandem - e.g., BellSouth - and use that LEC's network to make an indirect connection, rather than connecting directly with the RLEC cannot serve to impose additional costs on the RLEC by requiring delivery of traffic outside its network and service area. The tandem, which provides the transit function, is a virtual part of the CMRS Provider's network because it chose to indirectly connect via a third party provider, and financial responsibility for each party rests on its respective side of the POI.

In its assessment of the arguments, the Public Staff concluded that the RLECs should not be forced to pay for the CMRS Providers' choice to indirectly interconnect. The Public Staff argued that the RLECs are technically and financially responsible for the transport and delivery of its originated traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges incurred based on the use of a third party provider's network facilities.

As a starting point in our analysis, the Commission notes that reciprocal compensation is designed to compensate <u>both</u> parties for the additional costs of terminating local calls to each other's customers. The FCC concluded that, other things being equal, these rates should be symmetrical and should be based on the LEC's cost study or default proxy. See, In re *Implementation of Local Competition Provisions in the Telecommunications Act of 1996*, CC Docket No. 96-98 and CC Docket No. 95-185 (August 8, 1996), (*Local Interconnection Order,*) Para. 1085; 47 C.F.R. 51.711(a).

Clearly, the FCC also contemplated that "transport" includes third-party transit.[1] In the *Local Interconnection Order*, Para. 1039, the FCC observed that "[m]any alternative arrangements exist for the provision of transport between two networks," including "facilities provided by alternative carriers." The question in this docket is who is responsible for paying for such third-party transit. That question was essentially answered in Issue No. 1. It is the CMRS Provider who is financially responsible. The RLEC is responsible for transporting an originating call on its network only up to the single POI chosen by the CMRS Provider on the RLEC's network. The CMRS Provider is responsible for delivering the call the rest of the way.

The CMRS Providers have stated that they should not be made to pay the RLEC's transiting costs for calls originating on the RLEC's network. In fact, they are not paying the RLEC's costs but rather are being compensated by the RLECs through reciprocal compensation. The CMRS Providers have not raised the issue that the reciprocal compensation rate is not compensatory to them for traffic levels exchanged between the networks.

Nevertheless, the CMRS Providers adhere to the belief that there is an unfair distribution of costs, implying that they are not being sufficiently or completely compensated for such calls. However, even under the "one POI" rule that we are following here, there is an alternative remedy available to a disgruntled CMRS provider. It is asymmetrical rates. Under 47 C.F.R. 51.711(b) the FCC has stated that "[a] state commission may establish asymmetrical rates for transport and termination of local telecommunications traffic if the carrier other than the incumbent LEC...proves to the state commission on the basis of a cost study using forward-looking economics cost based methodology...that the forward-looking costs for a network efficiently configured and operated by the carrier other than the incumbent LEC...exceed the costs incurred by the incumbent LEC...and, consequently, that such a higher rate is justified."

The CMRS Providers have neither raised the issue of asymmetrical rates nor provided evidence for them. More importantly, they never requested them. Therefore, in accordance with our previous "one POI" decision in this case and *Alltel* , the CMRS Providers, not the RLECs, are responsible for the third-party transiting costs and are to be compensated through symmetrical reciprocal compensation rates.

CONCLUSIONS

The Commission concludes that the RLECs are technically and financially responsible for transporting and delivering their originating traffic to the chosen POI and for paying reciprocal compensation to cover the cost of terminating and completing the call beyond the POI, but they are not responsible for transit charges, based on the CMRS Providers' use of a third party provider's network facilities, beyond the POI.

[1] See 47 C.F.R. 51.701 (c), which defines transport as follows: "For the purposes of this subpart, transport is the transmission and any tandem switching of local telecommunications traffic subject to Section 251(b)(5) of the Act from the interconnection point between two carriers to the terminating carrier's end office switch that directly serves the called party, or equivalent facility provided by a carrier other than an incumbent LEC." Transit obviously is a form of transmission, and transmission is a component of transport.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

ISSUE NO. 3- MATRIX ISSUE NO. 6: What is the appropriate reciprocal compensation rate for each RLEC?

POSITIONS OF PARTIES

RLECs: The RLECs argued that the appropriate reciprocal compensation rate for MebTel is the \$0.0118 rate shown in the revised cost study and testimony of witness Skrivan; that the appropriate rate for Randolph is the \$0.01918 rate shown in the revised cost study and rebuttal testimony of witness Schoonmaker; and, that the appropriate rate for Ellerbe is the \$0.01918 rate shown in the revised cost study and rebuttal testimony of Randolph, which Ellerbe adopts as a surrogate for its costs.

CMRS PROVIDERS: The CMRS Providers asserted that the reciprocal compensation rates for each Petitioner should be established pursuant to the recommendations of CMRS Providers witness Conwell. Specifically, MebTel's reciprocal compensation rate should be \$0.0021 per minute; Randolph's rate should be \$0.0045 per minute; and Ellerbe's rate should be \$0.0053 per minute.

PUBLIC STAFF: The Public Staff stated that the appropriate reciprocal compensation rate is determined through application of the Public Staff's recommendations as outlined in its Proposed Order in this proceeding.

DISCUSSION

All of the cost issues presented in these dockets fall into two basic categories: they are either generic cost issues or sub-issues raised by ALLTEL and/or Cingular concerning the RLECs specific cost studies. This Finding of Fact reflects the Commission's conclusions for various cost issues before it that comprise the evidence and conclusions for Finding of Fact No. 4 and Findings of Fact Nos. 7 through 22. The Commission has made specific conclusions based on the evidence presented and, as a result, does not entirely concur in the rates recommended by either the RLECs or the CMRS Providers. Therefore, the RLECs should make modifications to their alternative cost studies as specified in the conclusions for the Finding of Fact No. 4 and Findings of Fact Nos. 7 through 22.

CONCLUSIONS

The Commission has made specific conclusions based on the evidence presented and, as a result, does not entirely concur in the rates recommended by either the RLECs or the CMRS Providers. Therefore, the RLECs should make modifications to their alternative cost studies as specified in the conclusions for the Finding of Fact No. 4 and Findings of Fact Nos. 7 through 22.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

ISSUE NO. 4 - MATRIX ISSUE NO. 6A: Must the RLECs' cost studies and rates comply with Section 252(d) of the Act and related FCC regulations?

POSITIONS OF PARTIES

RLECs: The RLECs argued that the RLECs' cost studies and rates are not required to comply with Section 252(d) of the Act and related FCC rules. The RLECs argued further that, as the Commission ruled in Docket No. P-100, Sub 159, the petitioning RLECs could establish evidence of their costs through alternative cost studies, for purposes of establishing reciprocal compensation pursuant to Section 251(b)(5) of the Act, without complying with the FCC's TELRIC rules and regulations.

CMRS PROVIDERS: The CMRS Providers asserted that the RLECs are not automatically relieved of their duty to comply with the FCC pricing and rate requirements in Section 252(d) of the Act and related FCC rules by the Commission's Order in Docket No. P-100, Sub 159. According to the CMRS Providers, the Act does not allow the RLECs a suspension or modification from Section 252(d) and related FCC regulations and, at the same time, allow the RLECs to enforce Section 251(b)(5) against the CMRS Providers without suspension or modification. Thus, the RLECs' cost studies and rates must comply with Section 252(d) and related FCC rules since the RLECs are attempting to enforce Section 251(b)(5) obligations against the CMRS Providers without suspension or modification.

PUBLIC STAFF: The Public Staff stated that the RLECs' cost studies and rates derived therefrom are not required to comply with Section 252(d) and related FCC rules. In Docket No. P-100, Sub 159, the Commission granted the RLECs a modification of the requirement that they perform TELRIC studies to determine appropriate reciprocal compensation rates pursuant to Section 251(f)(2) of the Act. Therefore, the Public Staff asserted in these dockets that the rates are not required to comply with Section 252(d) of the Act and the related FCC regulations.

DISCUSSION

Docket No. P-100, Sub 159 arose from a petition filed by several rural companies, including Citizens Telephone Company (Citizens), Ellerbe, MebTel, Town of Pineville d/b/a/ Pineville Telephone Company, and Randolph. These companies sought a modification of certain requirements found in Section 251(b)(5) of the Act concerning reciprocal compensation pursuant to Section 251(f)(2) of the Act. Further, the companies asked to be relieved of any requirement to provide TELRIC studies to any requesting carrier with respect to reciprocal compensation until such time as the FCC has made its final ruling concerning intercarrier compensation in CC Docket No. 01-92.

In Docket No. P-100, Sub 159, CMRS providers Cingular, Verizon Wireless, and Sprint PCS argued that the Commission can neither modify nor suspend the FCC's TELRIC pricing methodology because, under Section 251(f)(2), the Commission is granted authority to modify or suspend only certain obligations established by Section 251(b) or Section 251(c) and that the

Section 252(d)(2) TELRIC pricing standards are not among those obligations. The Commission explicitly rejected this argument and modified (but did not suspend) the RLECs' Section 251(b)(5) obligation as it related to the duty to establish reciprocal compensation arrangements for the transport and termination of telecommunications traffic. In rejecting the CMRS Providers' arguments, the Commission stated that: "[t]he Commission also believes that the CMRS Providers' legal arguments against such modification, while occasionally ingenious, are not persuasive" and that "the power to *modify* a reciprocal compensation obligation necessarily implies the power to suspend a TELRIC rate calculation requirement for good cause shown, given that the relevant statute authorizes *both suspension and modification*." *Modification Order*, pp. 13-14 issued on March 8, 2006 (emphasis in original). The Commission thereafter concluded that the RLECs "should not be required to perform TELRIC studies to establish reciprocal compensation rates (including the interim rate)" and that such "relief should continue until such time as the FCC shall have rendered its final ruling in CC Docket No. 01-92 concerning intercarrier compensation." *Modification Order*, p. 13. Finally, the Commission permitted the RLECs to conduct alternative cost studies to determine the appropriate reciprocal compensation rate using the following Guidelines:

1) The cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic.

2) The cost data may be a surrogate of the company's cost, but should be forward-looking and reflect an efficient network to the extent practicable.

3) The rates for transport and termination of traffic should be usage based.

4) The capital costs and structure should reflect the cost and structure approved by the Commission in previous decisions in Docket No. P-100, Sub 133d.

5) Depreciation should reflect the economic lives and net salvage values within the ranges established by the FCC.

6) The study should include a reasonable allocation of common costs to be added to direct costs.

7) The study should not include retail costs, opportunity costs, or revenues to subsidize other services.

The arguments made in this current proceeding by the CMRS Providers are essentially the same arguments made by the larger group of CMRS Providers in Docket No. P-100, Sub 159. In the current dockets, ALLTEL and Cingular now argue that the Act does not "allow the RLECs a suspension or modification from Section 252(d) and related FCC regulations and, at the same time, allow the RLECs to enforce Section 251(b)(5) obligations against the CMRS

Providers without suspension or modification." Proposed Order of CMRS Providers, p. 13. In the view of the CMRS Providers:

> If a state commission suspends or modifies an RLEC's obligation to enter transport and termination arrangements under Section(b)(5), then the RLEC will not be required to enter into such arrangements, and the Section 252(d)(2) pricing standards will be irrelevant. If the Section 251(b)(5) obligation is not suspended or modified, however, then the RLEC must enter into such arrangements, and the rates will be governed by Section 252(d)(2). The sections go together. Either both are suspended or modified or neither is. Under the act, the state commission cannot suspend or modify obligations under 252(d)(2) while leaving Section 251(b)(5) obligations in place. Otherwise, RLECs could force CMRS Providers to enter into reciprocal compensation arrangements not governed by the Section 252(d)(2) standards-a situation inconsistent with the Act.
>
> Proposed Order of CMRS Providers, p. 14.

According to the CMRS Providers, the RLECs have to choose either to have their Section 251 obligations suspended or modified pursuant to Section 251(f)(2) and, thereafter, forego entering Section 251(b)(5) transport and termination arrangements altogether; or, the RLECs are required to embrace their Section 251 obligations <u>and</u> the TELRIC-like pricing standards required by Section 252 of the Act.

This argument rests entirely upon the premise that the Act does not allow the RLECs a suspension or modification from Section 252(d) and related FCC regulations and, at the same time, allow the RLECs to enforce Section 251(b)(5) obligations against the CMRS Providers without suspension or modification. The CMRS Providers cite no authority in the Act or an Order to support this premise. Instead, it appears that the CMRS Providers have once again relied upon interpretations of Sections 251(b)(5), 252(d)(2) and 251(f)(2) of the Act individually and in isolation without due regard to the overall goal that Congress intended to accomplish when it adopted the Act.

The Act, as enacted by Congress, clearly recognizes that, in most instances, the principles articulated in the Act were to be uniformly and individually applied to telecommunication service providers. Uniformity in application was much desired and a necessary attribute of any legislation that was intended to transform a monopolistic, competition adverse telecommunications services market, which existed prior to 1996, into the pro-competitive model envisioned in the Act. In its wisdom, however, Congress also recognized that strict adherence to the uniform application of principles in every circumstance would be unwise and that a certain amount of flexibility was necessary in the application of those principles to small and rural telecommunications providers. Congress understood that small and rural telecommunications providers could be unduly affected by the forced application of many of the uniform provisions set forth in the Act and that this undue affect would undermine its overall goal of encouraging more robust and competitive telecommunication service options for all consumers. Congress, thus, allowed small and rural telecommunication providers either outright exemption from some requirements of the Act or the ability to apply to state commissions to opt out of or modify certain provisions of the Act that could be economically onerous if applied with unyielding rigidity.

The FCC was acutely aware of Congress' desire for uniformity in application except when small and rural carriers were affected when it adopted rules and policies to implement the Act. For instance, in its discussion in Section XI of its *Interconnection Order* entitled Obligations Imposed on LECs by Section 251(b), the FCC first posits the general principles that "Section 251(b)(5) provides that all LECs, including incumbent LECs, have a duty to 'establish reciprocal compensation arrangements for the transport and termination of telecommunications," (*Interconnection Order Paragraph* 1027), and thereafter requires that "states that elect to set rates through a cost study must use the forward-looking economic cost-based methodology . . . in establishing rates for reciprocal transport and termination when arbitrating interconnection arrangements" *Interconnection Order Paragraph 1056.* Later, however, the FCC in Paragraph 1059 of Section XI, expressly recognized that the general rule requiring rates to be set based upon this forward looking cost study[1] was subject to this small/rural LEC exception because of its potential to economically undermine the status of small and rural telecommunication companies by stating:

> We also address the impact on small incumbent LEC . . . We have considered the economic impact of our rules in this section on small incumbent LECs. For example, we conclude that termination rates for all LECs should include an allocation of forward-looking common costs, but find that the inclusion of an element for the recovery of lost contribution may lead to significant distortions in local exchange market. We also note that certain small incumbent LECs are not subject to our rules under Section 251(f)(1) of the 1996 Act, unless otherwise determined by a state commission, and certain other small incumbent LECs may seek relief from their commissions from our rules under Section 252(f)(2) of the 1996 Act. (Emphasis added) *Interconnection Order Paragraph 1059.* See also First Report and Order, 11 FCC Rcd 15499 Paragraphs 697, 706, 934, 1088 for similar acknowledgements of this distinction by the FCC.[2]

Thus, as a general proposition, reciprocal compensation rates should be determined by the use of a forward looking economic cost-based, ie., TELRIC, methodology except when certain small incumbent LECs can demonstrate a need for relief from those rules under Section 251(f)(2) of the Act. In those instances, reciprocal compensation rates may be

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[1] By regulation, the FCC adopted TELRIC as the forward looking cost study. §51.505.

[2] In addition, the United States Supreme Court has recognized the FCC's acknowledgement that State commissions have the authority to suspend or modify the application of TELRIC rules to rural telephone companies.

> [A]s the FCC has acknowledged, the smallest, rural incumbent local-exchange carriers most likely to suffer immediately from the imposition of unduly low rates are expressly exempt from the TELRIC pricing rules under 47 U.S.C. § 251(f)(1), and other rural incumbents may obtain exemptions from the rules by applying to their state commissions under § 251(f)(2).

Verizon Communications, Inc. v. F.C.C., 535 U.S. 467, 528 n. 39 (2002) (emphasis added) internal citations omitted).

determined by a methodology other than a strict forward looking economic cost based approach. As permitted, the RLECs sought such relief from the general FCC requirement that rates be determined using a strict forward looking economic based methodology pursuant to Section 252(f)(2) in Docket No. P-100, Sub 159. The RLECs did not, however, seek exemption or suspension from their Section 251(b)(5) obligations to enter into termination or transport arrangements. Because we recognized that requiring these small and rural RLECs to conduct cost studies based upon the strict TELRIC principles required by FCC rules implementing Section 252(d) would be economically onerous, we granted the RLECs the requested relief with the clear understanding that the RLECs would use the cost figures derived from the guidelines proposed by the Public Staff and adopted in the *Modification Order* as a basis for "establishing reciprocal compensations rates (including the interim rate)" required by the Act when they entered into termination or transport arrangements. *Modification Order*, p. 13.

In our view, this was and is a logical step that follows from the Act's express grant of authority allowing RLECs to apply to the Commission to opt out of costly TELRIC based studies to determine reciprocal compensation rates. We do not believe that Congress intended to allow the RLECs to opt out of undertaking the TELRIC study only to then require them to engage in a costly "TELRIC type" study to establish reciprocal compensation rates if they choose to modify rather than to suspend their obligations altogether under Section 251(b)(5) of the Act as the CMRS Providers here propose. That, in our view, would be illogical and would violate Congress' expressed intent. We decline to adopt such an interpretation. In light of this belief and for the reasons previously set forth, we conclude that the rates are not required to comply with Section 252(d) and the related FCC regulations.

CONCLUSIONS

Because the Commission modified the reciprocal compensation requirements of Section 251(b)(5) of the Act in Docket No. P-100, Sub 159, the RLECs are not required to perform strict TELRIC studies to establish reciprocal compensation rates, and the rates proposed for reciprocal compensation do not have to comply with all of the requirements set forth in Section 252(d) of the Act and related FCC rules.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

ISSUE NO. 5 – MATRIX ISSUE NO. 8: What is the appropriate interMTA traffic factor for each RLEC with each CMRS Provider?

POSITIONS OF PARTIES

RLECs: A default interMTA factor of 5% is appropriate for Randolph and Ellerbe. A default interMTA of 18.55% is appropriate and reasonable for MebTel. In lieu of a default factor, the RLECs would agree that the CMRS Providers can conduct traffic studies, subject to audit by the RLECs, to establish default interMTA factors. The parties agree that compensation for interMTA traffic will be paid at the RLEC's tariffed interstate access rate.

TELECOMMUNICATIONS – MISCELLANEOUS

CMRS PROVIDERS: InterMTA traffic factors should be developed on a company-specific basis and should apply only to compensable interMTA traffic. The parties have agreed that compensation will be paid at the rate contained in the RLEC's interstate access tariff. Based on Cingular's traffic studies, the interMTA factors should be:

Ellerbe – 2.2%
MebTel – 0.17%
Randolph – 1.8%

PUBLIC STAFF: The evidence before the Commission does not support any of the proposed default interMTA traffic factors. In addition, the Commission should not find either MebTel's proposed 18.55% interMTA factor to be reasonable or the methodology it used to determine this factor to be relevant to determining an interMTA traffic factor. The Commission should have the parties resolve this issue through additional negotiation and assisted, if necessary, by relevant traffic studies that are subject to audit by the RLECs.

DISCUSSION

This issue concerns compensation for interMTA traffic exchanged by the parties. The RLECs argued that it is necessary for the parties to include a factor for interMTA traffic in their interconnection agreements in order to recognize that some percentage of the traffic exchanged between the CMRS Providers and RLECs is interMTA, i.e., at the time the call commences the caller and the called party are located in different MTAs. The RLECs explained that the incidence of interMTA traffic occurs in two scenarios.

In the first scenario, there is CMRS-originated traffic that appears to be intraMTA when, in fact, it is interMTA. This traffic is called "misjurisdictionalized" traffic for which the RLEC should receive terminating access compensation rather than reciprocal compensation.

The second scenario results from the CMRS customer's ability to roam. The RLECs stated that when an RLEC originated call is delivered to a CMRS customer that has roamed outside the wireless customer's home MTA, the call is interMTA.

The RLECs contended that a default interMTA factor of 5% for Randolph and Ellerbe is appropriate and reasonable. MebTel stated that the interMTA factor for it should be much higher due to specific market characteristics involved with its service area. Specifically, MebTel explained that its Milton and Gatewood exchanges are in North Carolina but assigned to MTA 23 (the MTA covering southern Virginia), while essentially all of the remainder of North Carolina is assigned to MTA 6 (the MTA that includes all of North Carolina, except for Milton, Gatewood, and the Elizabeth City area). MebTel argued that the incidence of calling from the Milton and Gatewood exchanges to other North Carolina locations, all of which are in a different MTA, results in MebTel experiencing a higher rate of interMTA calling. The RLECs suggested that the interMTA calling originating in the MebTel service area is also subject to a higher incidence of interstate calling. Therefore, MebTel argued that the default interMTA of 18.55% is most appropriate for MebTel.

The RLECs stated that a higher incidence of interMTA calling is likely because Cingular does not have a tower in either the Milton or Gatewood exchanges. Cingular would have to route an originating call from its customer to either a cellular tower in MTA 23 or MTA 6. If the call is routed to a cellular tower in MTA 6, then that call is an interMTA call. The RLECs therefore argued that, because of the various circumstances relating to the MebTel's Milton and Gatewood exchanges, it is reasonable to conclude that these two exchanges would experience a high level of interMTA traffic.

The RLECs noted that the FCC, in its proceeding which addressed universal service funding obligations, has established a 37.1% interstate default factor for CMRS traffic. Witness Skrivan testified that an interMTA factor of one-half of the FCC interstate default factor, or 18.55%, would be a reasonable interMTA factor for MebTel. MebTel commented that, while an interMTA default factor of 18.55% would be appropriate, it would agree to an interMTA default factor of one-fourth of the FCC's default interstate factor, or 9.275%, as the default interMTA factor.

The RLECs proposed an interMTA default factor of 5% for Randolph and Ellerbe. The RLECs stated that there is no way to validate interMTA land originated calls to cellular customers. According to the RLECs, Cingular conceded that it also did not have any information to verify its interMTA cellular originated calls to landline customers. The RLECs asserted that, since a 5% default interMTA factor was approved by the Commission in a negotiated interconnection agreement between Sprint and Carolina Telephone in Docket No. P-7, Sub 1034, the same default factor should be approved for them in this instance.

The RLECs noted that Cingular has no records to support its study of misjurisdictionalized traffic. The RLECs asserted that they have no means to audit a record to determine the reasonableness of the Cingular proposal.

Cingular stated that it is not seeking interMTA compensation from the RLECs. However, Cingular conceded that default factors are necessary because the parties lack the ability for billing purposes to determine the originating and terminating cell sites at the beginning of a wireless originated cellular call.

Cingular commented that it has interMTA liability for wireless originated traffic that crosses an MTA boundary and that Cingular does not hand-off to an interexchange carrier (IXC) for transport. If Cingular hands off a wireless originated, interMTA call to an IXC, the IXC will pay the terminating access to the RLEC terminating the call. Cingular contended that its network is designed to hand off virtually all wireless originated, interMTA traffic to IXCs. Further, only a small percentage is not handed off to IXC, which is why the interMTA factors for wireless originated traffic are so low. Cingular asserted that it submitted a traffic study that demonstrates the percentage of wireless originated traffic that Cingular does not hand off to IXCs.

The Public Staff noted that the RLECs stated that the Commission should approve their proposed interMTA factors, because these factors reflect the fact that some percentage of CMRS originated traffic terminated to the RLECs will originate outside the MTA. Whenever a RLEC customer calls a CMRS customer that is roaming outside the MTA, the call becomes an interMTA call. The Public Staff stated that no industry capability exists to verify interMTA land-to-mobile calls, because the RLEC has no way to determine whether the CMRS customer with an intraMTA number is roaming outside the MTA during the call.

The Public Staff observed that MebTel's argument for an 18.55% default interMTA factor was based on the FCC's study to determine the applicable contribution factor for universal service support which was based on the interstate revenue levels as reported by the CMRS service providers. Because wireless traffic has been growing over the past ten years, the FCC increased its Safe Harbor rate from 28.5% to 37.1%.

While interstate traffic does not correlate exactly to interMTA traffic, witness Skrivan testified that the one-third portion of interstate calling shows that interMTA traffic must be more than de minimis. Witness Skrivan further testified that, "because the FCC finds that 37% of the wireless traffic is interstate, MebTel believes that it is reasonable to use one-half of that as a default interMTA factor."

The Public Staff noted that MebTel's Milton and Gatewood exchanges are physically located in North Carolina but are assigned to the Virginia MTA. These exchanges have EAS calling to Yanceyville and Roxboro, which are located in a different MTA. Consequently, every wireline to wireless call from Milton or Gatewood to Yanceyville and Roxboro is an interMTA intrastate call, subject to intrastate access charges. The Public Staff observed that witness Skrivan estimated that 50% of the land-to-mobile calling from those exchanges is interMTA; he disagreed that the majority of the traffic was local even if it was intrastate.

The Public Staff observed that MTA boundaries are not always congruent to state boundaries, so interMTA traffic is not always the same as interstate traffic. The FCC has also held that the local calling scope of a CMRS carrier is the MTA, which in some cases cross state boundaries, however if the MTA boundary crosses a state boundary the calls made are considered within the local calling scope of the CMRS Providers.

The Public Staff acknowledged that radio signals can cross the boundary to a cell tower in a different MTA and therefore appear to a CMRS provider as intraMTA when it should be interMTA, and vice versa. The Public Staff suggested that, although most of North Carolina is in MTA 6, intrastate traffic may simultaneously be interMTA, as in the case of MebTel's Milton and Gatewood exchanges.

The Public Staff stated that, because of the difficulty in determining intraMTA and interMTA traffic proportions, wireline and wireless carriers frequently negotiate a factor or percentage to apply to all traffic. The Public Staff noted that the Commission has approved several interconnection agreements with negotiated default interMTA traffic factors to resolve reciprocal compensation rates. The Public Staff pointed to several negotiated interconnection agreements in which the parties mutually agreed upon a default interMTA traffic factor of 1%.

Randolph and Ellerbe cited to a negotiated interconnection agreement approved by the Commission in Docket No. P-7, Sub 1034, between Carolina Telephone and Telegraph Company, Central Telephone Company, and NEXTEL South Corporation containing a 5% interMTA traffic factor. The Public Staff argued that the Commission should be reluctant to rely solely upon a negotiated interconnection agreement as evidence that Randolph's and Ellerbe's proposed 5% factor should be approved. The Public Staff asserted that, while the Commission may have approved such an agreement, that approval does not necessarily constitute a finding that the factor was reasonable for all subsequent arbitrations.

The Public Staff noted that a two-week traffic study developed by a third party resulted in a default interMTA factor of 1.8% for Randolph and 0.17% for MebTel. These default factors represent the amount of misjurisidictionalized interMTA traffic according to the results of the traffic study completed for Cingular.

The Public Staff also addressed MebTel's proposed 18.55% default interMTA factor by observing that MebTel extrapolated the proposed default rate from an FCC study on universal service, which does not address the issue here. MebTel's proposed interMTA rate is based on the higher of the FCC's estimation of the percentage range of nationwide interstate traffic that the FCC calculated for another purpose. Furthermore, the Public Staff asserted that MebTel's proposed default interMTA factor is conspicuously higher than any of the other proposed factors in this case.

The Public Staff suggested that Cingular's position on this issue was not persuasive, in that Cingular's proposed rates were provided in response to a data request and were based on a twenty day traffic study by a third party. Furthermore, the results of the study were made a part of the record by a RLEC witness.

The Public Staff stated that the parties appear to agree that traffic studies provided by Cingular, either produced by itself or through a third party, can be used to establish interMTA billing. However, the degree to which the RLECs should be allowed to audit the results remains a point of contention.

After careful consideration, the Commission determines that the 18.55% default interMTA factor proposed by MebTel is too high and unsubstantiated based on information MebTel used to reach its recommendation. Furthermore, the proposed interMTA default rate of 5% for Randolph and Ellerbe is drawn from a previous interconnection agreement and is not supported by the evidence in this proceeding. Therefore, the Commission is left with the question as to how best to proceed in reaching a decision on the issue of establishing an interMTA default factor that serves the interests of the parties in this proceeding.

Generally speaking, the Commission is not persuaded that the question regarding interMTA traffic disparity between the RLECs and Cingular cannot be resolved to the mutual satisfaction of each of the parties involved in this proceeding. Based on the level of contention surrounding this issue, the Public Staff's recommendation that further traffic studies be undertaken by Cingular and that the studies be audited by the RLECs, if desired, appears to be a reasonable starting point to reach a resolution.

The Commission also notes with interest the arguments that MebTel raised concerning the level of interMTA traffic based on the geographic location of the Milton and Gatewood exchanges between the MTAs in question, as well as the proximity of these two exchanges to the

North Carolina – Virginia border. The Commission also observes that the evidence stated that Cingular has no cellular towers in either the Milton or Gatewood exchanges. There are considerations of network design and topology that must be addressed by the service providers, and the Commission will presume that standard industry engineering principles and network design concepts are being applied by the respective service providers in this matter, both wireline and wireless.

As the Public Staff pointed out, there have been several negotiated interconnection agreements in which the parties mutually agreed upon a default interMTA traffic factor of 1%. The RLECs in this proceeding are obviously quite far from a default interMTA factor of 1% - Randolph and Ellerbe proposed a 5% interMTA factor, and MebTel proposed an 18.55% interMTA factor. The Commission concurs with the Public Staff that the Commission's approval in a previous negotiated interconnection proceeding does not necessarily constitute a finding that a factor, the percent of interMTA traffic between parties, would be reasonable for all subsequent arbitrations.

The Commission observes that the mobile-to-landline calling ratio of 75/25 also typically reflected in negotiated interconnection agreements provides no meaningful guidance in setting a default interMTA factor. The Commission concludes that the level of nonjurisdictionalized traffic between these parties, although characterized as not being de minimis, can be reasonably estimated.

Therefore, at this point, the Commission determines that the most equitable procedure to follow in resolving the issue of determining the interMTA traffic factor is to direct Cingular to develop an originating traffic study for a 30-day period. This study is to be used to determine the initial interMTA default factor to be used between the parties.

CONCLUSIONS

The Commission concludes that Cingular is to develop a 30-day originating traffic study which is to be used in establishing a default interMTA traffic factor. The parties are encouraged to negotiate between themselves. The Public Staff is encouraged to offer their good offices to the parties to resolve this issue.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

ISSUE NO. 6 - MATRIX ISSUE NO. 8C: Should the CMRS Providers pay the RLECs originating access on landline originated interMTA calling to a "local" CMRS number that is roaming outside the MTA at the time of the call?

POSITIONS OF PARTIES

RLECs: Yes. When an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber, because the wireless subscriber is roaming outside the MTA at the time the call is made, the RLEC is entitled to be paid originating access. As described in Footnote 2485 of the *FCC's First Report and Order* cited in the RLEC's testimony, the CMRS provider is responsible for payment of access charges in such a scenario.

CMRS PROVIDERS: No. When the RLEC delivers the call to the CMRS provider, the call is completed from the RLEC's viewpoint. No interexchange carrier selection or routing is made by or on behalf of the RLEC on such a call and no access is involved. How a wireless carrier handles the call thereafter on its own network does not affect the compensation owed to the RLEC.

PUBLIC STAFF: When an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber because that subscriber is roaming outside the MTA at the time the call is made, the RLEC is entitled to be paid originating access by the CMRS provider.

DISCUSSION

The RLECs commented that their switches do not know where a Cingular customer is located at the moment an RLEC customer places a call to that wireless customer. The RLECs contended that their switches send the call to Cingular and it is Cingular that locates its roaming customer and forwards the call through its network for delivery to that customer. There is no way for the RLEC to determine which calls are going to roaming wireless customers, and, absent an interMTA traffic factor, the RLEC is not compensated for the originating access service it provides to Cingular in connection with such calls.

The RLECs argued that, when Cingular routes that call to its subscribers that are roaming outside the MTA at the time the call is made, it is interMTA traffic and the RLEC is entitled to be paid originating access. The RLECs further argued that, under Footnote 2485 of the FCC's *First Report and Order* cited in RLEC testimony, the CMRS provider is acting as an IXC in such a scenario and is responsible for payment of access charges to the originating ILEC. The RLECs asserted that if Cingular chooses to forward interMTA calls to its roaming customer, the FCC has made it clear that in doing so Cingular is providing interstate, interexchange service and is obligated to pay access charges to the ILEC that originated the call.

Cingular countered that the key to the RLECs' interpretation of Footnote 2485 from the FCC's *First Report and Order* has to do whether the wireless carrier owes access charges for landline originated traffic when the wireless carrier is providing interstate, interexchange service. Cingular contended that this does not mean that every locally dialed landline call routed out of state and across an MTA boundary to a wireless subscriber automatically requires the CMRS provider to pay originating access charges to the landline carrier. Cingular pointed out that such charges accrue only when the CMRS provider carries the call on its own network across the MTA boundary and thus acts as an IXC. If the CMRS provider hands off the call to an IXC for transport across the MTA boundary to the terminating wireless customer, the CMRS provider is not acting as an IXC, is not providing interstate, interexchange service and therefore is not required to pay originating access to the landline carrier.

The important question, according to Cingular, for determining compensation responsibility for landline originated, interMTA traffic is thus the same as for determining compensation responsibility for wireless originated, interMTA traffic: what percentage of landline originated calls to local wireless number terminated in another MTA are transported by IXCs? Cingular asserted that, in the case of Cingular, the percentage in question is zero, because, when the call is initialized, Cingular hands off all landline originated, interMTA traffic to an IXC. Therefore, Cingular stated that it has no liability to the RLECs for land line originated, interMTA traffic.

The Public Staff stated that the RLECs asserted that, given the network configuration of their networks and the nature of MTA boundaries, all interMTA calls would be interstate. The Public Staff further stated that when the RLEC customer originates a call to a roaming CMRS customer, the CMRS provider is providing an interexchange call. As such, the Public Staff contended that the RLEC's Interconnection Agreement should clearly identify the above describer traffic as Non-Reciprocal Compensation traffic that is subject to access charges.

Witness Skrivan explained, based on the network arrangements that exist today, the MebTel switches do not know where the CMRS customer is actually located when a MebTel customer places a call to a wireless customer. The Public Staff stated that the CMRS provider must then find the roaming customer to send the call to it. MebTel cannot determine whether the calls are roaming and is not compensated for its originating access service unless the CMRS provider pays for this service.

The Public Staff suggested that the CMRS providers possess the information on where they send calls to their subscribers, and are therefore able to identify a call as intraMTA or interMTA. However, the Public Staff pointed out that the RLEC has a record showing the number called, and the data to show whether that number is assigned to an exchange that is within the MTA.

The issue here, as framed by the Public Staff, pertains to the RLEC handing off an apparent intraMTA call to a CMRS provider and that provider delivering it to its roaming subscriber outside the MTA. However, the Public Staff stated that, while there is no definitive statute or FCC rule on this matter, the FCC's Footnote 2485 in the *First Report and Order* does provide that when a CMRS company provides its customers with a service whereby a call to a subscriber's local cellular number will be routed to it over interstate facilities when the customer is roaming, the cellular carrier is providing interstate, interexchange service, not local exchange service. As such, the Public Staff argued that, when an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber and that subscriber is roaming outside the MTA at the time the call is made, it is an interMTA call and the RLEC is entitled to be paid originating access by the CMRS provider.

After careful consideration, the Commission believes that when an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber and that subscriber is roaming outside the MTA at the time the call is made, it is an interMTA call and the RLEC is entitled to be paid originating access by the CMRS provider. However, the Commission is not convinced that Cingular, in this case, is willfully and intentionally refusing to pay access charges when incurred. Cingular stated that all of its interMTA traffic is handed off to an IXC for call completion so that Cingular does not carry the call on its own network across the MTA boundary. Furthermore, Cingular agreed this traffic is included in the "nonjurisdictionalized" interMTA default factor and hence compensation is made to the RLECs for this incidence. This point has not been refuted.

As is clearly evident from Footnote 2485, which has been referenced by all the parties in this docket, there is language to establish that when a CMRS company provides its MTA customers with call completion for a call routed to it over interstate facilities when the customer is roaming, the cellular carrier is providing interstate, interexchange service, not local exchange service. In this instance, an access charge obligation is created by Cingular to the respective RLEC. This citation applies to instances in which RLECs may be entitled to receive access charge compensation for originated traffic subject to roaming for call completion by the CMRS provider.

If an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber which the CMRS subscriber carries across the MTA boundary rather than handing it off to an IXC and that subscriber is roaming outside the MTA at the time the call is made, the call is an interMTA call, and the RLEC is entitled to be paid originating access by the CMRS provider. The compensation of access charges can occur both directly and indirectly as expressed through the application of the interMTA default traffic factor.

CONCLUSIONS

The Commission concludes that, when an RLEC customer originates what turns out to be an interMTA call to a CMRS subscriber which the CMRS subscriber carries across the MTA boundary rather than handing it off to an IXC and that subscriber is roaming outside the MTA at the time the call is made, it is an interMTA call, and the RLEC is entitled to be paid originating access by the CMRS Provider. The compensation of access charges can occur both directly and indirectly, as an exception, as expressed through the application of the interMTA default traffic factor.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

ISSUE NO. 7 – MATRIX ISSUE NO. 17: Should the investment in the Mebane DMS switch be included in the MebTel cost study (in addition to the Mebane DCO switch)?

POSITIONS OF PARTIES

RLECs: No. The RLECs stated that MebTel has revised its position on this issue, and consents to removal of its Mebane DMS switch, which is presently in reserve, from the computation of its investment for the establishment of transport and termination rates. The RLECs stated that, because of the imminent exhaust of its Mebane DCO switch, MebTel points out that its reciprocal compensation rate will, in the future, be higher because the Mebane DMS switch will soon be serving MebTel and its customers. The RLECs noted that, if the Mebane DMS switch is removed from MebTel's cost study, MebTel's evidence is that its reciprocal compensation rate would be $0.0118. The RLECs asserted that removal of the Mebane DMS switch investment from MebTel's study resolves Matrix Issue No. 17.

CMRS PROVIDERS: No. The CMRS Providers argued that it is inappropriate for MebTel to recover costs not caused by the CMRS Providers. The CMRS Providers asserted that, since the Mebane DMS switch does not provide any service to MebTel, and therefore does not switch any

CMRS traffic for MebTel, all costs of that switch should be excluded from MebTel's transport and termination rate.

PUBLIC STAFF: No. The Public Staff stated that the investment and associated costs of the Mebane DMS switch should not be included in MebTel's cost study.

DISCUSSION

The CMRS Providers stated in their Post-Hearing Brief that MebTel is not justified in seeking to recover part of the costs of a switch that currently is not providing any service for MebTel.

The CMRS Providers further noted in their Proposed Order that the Commission's cost study Guidelines expressly state that the cost data to be used in the RLECs' cost studies should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic. The CMRS Providers maintained that MebTel witness Skrivan confirmed during the evidentiary hearing that the Mebane DMS switch was providing service only for MebTel's CLP affiliate.

The Public Staff noted in its Proposed Order that witness Skrivan testified that MebTel's cost study included all costs categorized as end office switching in the separations study. The Public Staff further commented that witness Skrivan stated that the Mebane DMS switch is not presently providing any switching for MebTel. The Public Staff asserted that MebTel intends to use the Mebane DMS switch to support the nearly exhausted Mebane DCO switch. The Public Staff noted that, under cross examination, witness Skrivan stated that the investment cost for the Mebane DMS switch is $2,439,512.

The Public Staff noted that CMRS Providers witness Conwell testified that the CMRS Providers should not be required to pay reciprocal compensation rates that include the cost of a switch that is not providing service. The Public Staff agreed. The Public Staff asserted that the central office investment amounts that MebTel uses in its cost study should not include the costs of switches that are not used to provide service.

The RLECs stated in their Proposed Order that MebTel has revised its position on this issue since the time of the evidentiary hearing, and has consented to the removal of its Mebane DMS switch from the computation of its investment for the establishment of transport and termination rates. Therefore, the RLECs noted, this issue is resolved.

The RLECs stated in their Post-Hearing Brief that MebTel was withdrawing the Mebane DMS switch from its cost calculation in this docket without prejudice to its right to include the investment associated with that switch in future rate proceedings after the Mebane DMS switch has begun providing service to MebTel customers.

The Commission notes that MebTel has agreed to remove the investment in the Mebane DMS switch from MebTel's cost study. The Commission finds that this issue has been resolved, and,.therefore, a Commission decision on this issue is not necessary.

CONCLUSIONS

The Commission concludes that the parties have agreed that the investment in the Mebane DMS switch should be excluded from MebTel's cost study.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

ISSUE NO. 8 – MATRIX ISSUE NO. 18: What total switch investment per line should be used for MebTel's cost study?

POSITIONS OF PARTIES

RLECs: The RLECs argued that MebTel's position is that its cost study, including the amount of direct switch investment included in that study of $621 per line, is consistent with the Commission's alternative cost study Guidelines. Commission Note: The RLECs agreed in Finding of Fact No. 7 to the removal of the Mebane DMS switch from MebTel's cost study. Therefore, $2,439,512 would be removed from the switch investment amount proposed by MebTel. The impact on the switching investment per line would be a decrease of $163, to a proposed amount of $458 per line.

CMRS PROVIDERS: The CMRS Providers recommended that the Commission adopt a per-line switch investment for MebTel of $143.

PUBLIC STAFF: The Public Staff asserted that the issue before the Commission concerns the total amount of switch investment to use in MebTel's alternative cost study. The Public Staff believes that the appropriate amount should exclude the Mebane DMS switch and exclude the line port, or non-traffic sensitive, portion of MebTel's remaining three switches.

DISCUSSION

The RLECs stated in their Proposed Order that MebTel's position is that its cost study, including the amount of direct switch investment included in that study, is consistent with the Commission's alternative cost study Guidelines. The RLECs noted that MebTel contends that the FCC's *Tenth Report and Order* (the *USF Inputs Order*[1]), which is the source of data that CMRS Providers witness Conwell advocated applying to MebTel, was, as shown by its title, applicable to nonrural LECs, such as AT&T and Verizon. The RLECs maintained that MebTel contended that this *Order* is of little or no relevance to the task of setting reciprocal compensation rates for the RLECs, as they are rural telephone companies and that data from this *Order* concerning high cost support should not be used to develop switch cost estimates for them.

The RLECs further asserted that the CMRS Providers' proposed figure of $143 per line is based on data in 1999 dollars from the FCC's *USF Inputs Order*, reduced by 12% to reflect what they believe is a decline in switch costs from 1999 to 2006. The RLECs noted that the CMRS

[1] In the Matter of Federal-State Joint Board on Universal Forward-Looking Mechanism for High-Cost Support for Non-Rural LECs, CC Docket No. 96-45 and CC Docket No. 97-160, released on November 2, 1999.

Providers contended that this investment complies with Guideline No. 1 in that it is easily obtainable and verifiable, and they argued that it complies with Guideline No. 2 in that it is forward-looking and reflects an efficient network to the extent practicable.

The RLECs noted that the CMRS Providers contended that the percentage of total switching annual costs per line for MebTel recoverable in its transport and termination rate is 12.8%. The RLECs stated that this is a product of the ratio between CMRS Providers witness Conwell's recommendation that MebTel use $18.33 per line investment from the HAI 5.0a model, to his recommended switch investment of $143 per line.

The RLECs stated that MebTel's use of data reflecting its actual switching investment is not inconsistent with the Commission's cost study Guidelines because the data used by MebTel was easily obtainable, verifiable, and the CMRS Providers have not proven that it was practicable for MebTel to secure a quote for a new switch or use other sources of data not relating to MebTel. The RLECs maintained that, for the reasons described by Randolph witness Schoonmaker, it would not have been as easy, as suggested by witness Conwell, for any of the RLECs to secure a vendor quote for a new switch. The RLECs also asserted that witness Conwell has no experience in buying switches for RLECs or in obtaining switch price quotes.

The RLECs noted that witness Conwell proposed the use of investment inputs from the FCC's *USF Inputs Order*, which concerned the establishment of high cost support for nonrural LECs. The RLECs maintained that witness Conwell then proposed to reduce those inputs by approximately 90% based on his arguments as to which switch costs should be excluded. The RLECs asserted that, while some data on smaller ILECs may have been included in the *USF Inputs Order*, the underlying proceeding did not directly concern rural ILECs. The RLECs also maintained that that proceeding concerned the establishment of high cost support for nonrural ILECs; it did not concern the establishment of reciprocal compensation rates for rural telephone companies. The RLECs argued that the data contained in Public Staff Conwell Cross Examination Exhibit No. 1 is more persuasive evidence as to RLEC switching investment costs[1]. The RLECs stated that that exhibit provides a portion of an FCC ARMIS report showing switching investment per access line for the largest ILECs in North Carolina.

The RLECs maintained that the FCC ARMIS report data for large North Carolina ILECs showed, for example, that AT&T's switching investment per line in North Carolina ranged from $387 per line in 1999 to $551 per line in 2006. The RLECs further noted that the ARMIS report data showed that Verizon's switching investment per line in North Carolina ranged from $698 per line in 1999 to $1,005 per line in 2006. The RLECs noted that, obviously, AT&T and Verizon are much larger ILECs than MebTel or the other RLECs, and it is reasonable to conclude that the RLECs' switch investment cost is at least as high as those of these very large ILECs. The RLECs asserted that these data corroborate the reasonableness of the switch investment reflected in the RLECs' cost studies.

[1] This Exhibit shows switching investment and expense per access line served for AT&T and Verizon based on the FCC's Automated Reporting Management Information System (ARMIS) Report 43-07, Table 1.

The RLECs argued that MebTel's cost study was prepared in accordance with the Commission's alternative cost study Guidelines, and the switch investment of $621 per line was appropriately used in MebTel's alternative cost study.[1]

The RLECs argued in their Post-Hearing Brief that the Commission should reject witness Conwell's proposed use of investment inputs from the FCC's *USF Inputs Order*. The RLECs asserted that, instead, the Commission should accept MebTel's revised study results as corroborated by the data contained in Public Staff Conwell Cross Examination Exhibit No. 1. The RLECs maintained that these data, which show that the switch investment costs per line for the largest North Carolina ILECs, range from slightly less than to significantly greater than MebTel's and Randolph's investment calculations. The RLECs asserted that they do not propose that the Commission substitute these data for the RLECs' own cost study. The RLECs opined that, instead, the Commission should be reassured by the fact that the RLECs compute their own switch investment for the purposes of establishing transport and termination rates at levels equal to or lower than AT&T's and Verizon's, even though the RLECs are a fraction of the size of those ILECs.

The RLECs asserted that the Commission should find that the CMRS Providers have failed to prove that it was practicable for the RLECs to secure quotes for a new switch or use other sources of data not relating to the RLECs. The RLECs maintained that, as shown by the testimony of witness Schoonmaker, it would not have been as easy as suggested by witness Conwell for any of the RLECs to secure a vendor quote for a new switch. The RLECs argued that, further, witness Conwell has no experience in buying switches for RLECs or obtaining switch price quotes.

The CMRS Providers stated in their Proposed Order that the switch investment claimed on MebTel witness Skrivan Cross Examination Exhibit No. 7 constitutes MebTel's embedded investment in four switches, one of which is not providing service to MebTel. The CMRS Providers maintained that witness Skrivan admitted at the hearing that the investments shown on Skrivan Cross Examination Exhibit No. 7 constitute "the historical book cost of the switches".

The CMRS Providers argued that the only evidence in the record of MebTel's forward-looking switch costs is contained in the direct testimony of witness Conwell, in which he stated that a switch investment of $143 per line, based on FCC switch cost data in 1999 dollars from the *USF Inputs Order*, adjusted for a 12% decline in switch costs to 2006 should be used. The CMRS Providers noted that this proposed per line switch investment complies with the Commission's cost study Guidelines because it is a reasonable, forward-looking switching investment and is easily obtainable and verifiable.

The CMRS Providers asserted in their Post-Hearing Brief that MebTel's embedded investments, plus including the embedded investment in a switch not providing service to

[1] The RLECs agreed in Finding of Fact No. 7 to the removal of the Mebane DMS switch from MebTel's cost study. Therefore, $2,439,512 would be removed from the switch investment amount proposed by MebTel. The impact on the switching investment per line would be a decrease of $163, to a proposed amount of $458 per line.

MebTel customers, equates to a switching investment per line of $621[1]. The CMRS Providers argued that this is a startling high figure. The CMRS Providers noted that, during the hearing, the Public Staff presented ARMIS data for AT&T and Verizon to witness Conwell showing the companies' embedded switching investment per line over time in North Carolina. The CMRS Providers asserted that AT&T's switching investment per line in 2006 was $551. The CMRS Providers further argued that the switching investments per line for AT&T, however, are not comparable to those of MebTel or the other RLECs. The CMRS Providers maintained that AT&T's switching investment per line of $551 includes investments in packet switches, tandem switches, and other network elements, which MebTel and the other RLECs do not have. The CMRS Providers asserted that, when AT&T's switching investment per line is adjusted to remove these investments, the remaining per-line investment is well below that represented by MebTel ($621 per line). The CMRS Providers maintained that, furthermore, MebTel's $621 per line switch investment is overstated, independent of comparisons to AT&T or Verizon, due to the inclusion of the nonworking Mebane DMS switch and to the high, unsubstantiated investment in the Milton/Gatewood switches.

In addition, the CMRS Providers noted that the switching investment per line claimed for the Milton/Gatewood switches is an even more startling $1,153 per line. The CMRS Providers stated that when witness Skrivan was asked on cross-examination if he had any knowledge of why the claimed investment in the Milton/Gatewood switches was so high, witness Skrivan replied, "No".

The CMRS Providers stated that witness Skrivan did concede, however, that the overall investment per line figure of $621 claimed by MebTel was high because of: (1) the high per line investment claimed for the Milton/Gatewood switch; and (2) the inclusion of the investment for the Mebane DMS switch, which is serving no MebTel lines.

The CMRS Providers maintained that Skrivan Cross Examination Exhibit No. 10 shows that the claimed investment for Milton/Gatewood of $1,153 per line is literally "off the chart". The CMRS Providers noted that Skrivan Cross Examination Exhibit No. 10 is a pleading filed by the Rural Utilities Service (RUS) in the same docket that produced the FCC's *USF Inputs Order* containing the FCC's switch cost data. The CMRS Providers asserted that Table 3 and Table 4 of Skrivan Cross Examination Exhibit No. 10 show actual rural company switch cost data supplied to the FCC by the RUS. The CMRS Providers stated that, during cross examination, witness Skrivan admitted that the claimed investment for the Milton/Gatewood switches, a host/remote pair, of $3,931,474 is almost four times higher than the total of the most expensive host and remote switches in the RUS study.

The CMRS Providers argued that the only evidence in the record of MebTel's forward-looking switch costs is contained in the direct testimony of witness Conwell in which he recommended a switch investment of $143 per line, based on FCC switch cost data in 1999 dollars from the *USF Inputs Order*, adjusted for a 12% decline in switch costs to 2006. The CMRS Providers asserted that this proposed per line switch investment complies with the Commission's cost study Guidelines because it is easily obtainable and verifiable.

[1] Removal of the Mebane DMS switch (See Finding of Fact No. 7) would reduce this amount to $458.

The CMRS Providers noted that MebTel claimed that the use of forward-looking cost data was not practicable. However, the CMRS Providers asserted that MebTel made no effort to seek vendor quotations for the current cost of switches. The CMRS Providers argued that MebTel also did not make any effort to find the publicly available data in the FCC *USF Inputs Order*. The CMRS Providers maintained that they have made the data available, and they should be utilized.

The Public Staff recommended in its Proposed Order that the Commission decline to perform the mathematical computation to calculate the switching investment per line. The Public Staff noted that making this calculation is useful only if using the alternative cost study presented by witness Conwell. The Public Staff asserted that, while the basic methodology employed by witness Conwell is not unreasonable, it is not dissimilar from the basics employed by MebTel in its study. The Public Staff recommended that the Commission decline to use the switch investment of $143 per line recommended by witness Conwell.

The Public Staff asserted that, as noted by Randolph witness Schoonmaker, the switch investment of $143 per line is based upon FCC switch cost data from its *USF Input Order* which witness Conwell then adjusted to 2006 dollars. The Public Staff stated that, regardless of how the investment amount was calculated, the amounts used in that *Order* pertain to nonrural carriers. The Public Staff argued that using a switch value that is substantially influenced by cost prices available to large ILECs is of questionable relevance when determining the switch investment for rural, and therefore, smaller carriers. The Public Staff further suggested that the cost data are dated and do not reflect functionalities that have been mandated by the FCC since 1999.

The Public Staff maintained that the record does not reveal the components of witness Conwell's proposed investment of $143 per line. The Public Staff stated that the cross examination of witness Skrivan implied that the only investments that the CMRS Providers believe are appropriate for consideration are those that are specific to the switch itself. The Public Staff maintained that, as noted in MebTel's cost study, there is associated land and buildings investment. The Public Staff stated that, for example, a modern switch cannot function without at least the climate control available from a building.

The Public Staff recommended that the Commission conclude that the switching investment used in the MebTel alternative cost study better represents the costs it can expect to incur. The Public Staff further proposed that the Commission find that the study should exclude the Mebane DMS switch investment (see Finding of Fact No. 7) and only include the traffic sensitive portions of the Milton, Gatewood, and Mebane DCO switches (See Finding of Fact No. 10).

The Commission notes that, as discussed in Finding of Fact No. 7 hereinabove, MebTel has agreed to remove the investment in the Mebane DMS switch from its cost study. Therefore, MebTel's original recommendation of $621 per line would be reduced to $458 per line to reflect the removal of $2,439,512 for the Mebane DMS switch. The calculation is reflected below:

Switch	Cost
Mebane DCO	$2,951,485
Milton/Gatewood	+$3,931,474
Total investment	$6,882,959 divided by
Access Lines	15,023
Switch Investment per Line	$458

In this proceeding, MebTel has proposed using its historical, book cost of its switch investment as outlined above to produce a proposed $458 per line switch investment figure. The CMRS Providers have recommended that the Commission use a figure of $143 per line which was derived based on FCC switch cost data in 1999 dollars from the FCC's *USF Inputs Order*, adjusted for a 12% decline in switch costs to 2006. The Commission notes that witness Conwell described his calculations on pages 27 and 28 of his direct testimony; however, the Commission has been unable to determine how the $143 figure was calculated[1]. Further, the Commission agrees with the RLECs and the Public Staff that the FCC's *USF Inputs Order* pertains to nonrural carriers, which will necessarily have different switching costs from rural carriers such as MebTel[2]. In addition, the *USF Inputs Order* was released eight years ago, in 1999. The Commission agrees with the Public Staff that the cost data used in the *USF Inputs Order* is dated and would not reflect functionalities that have been mandated by the FCC since 1999.

In addition, the Commission finds persuasive the RLECs' argument that the Commission should be reassured by the fact that the RLECs compute their own switch investment for the purposes of establishing reciprocal compensation rates at levels equal to or lower than AT&T and Verizon as detailed in Public Staff Conwell Cross Examination Exhibit No. 1. The Commission notes that MebTel's proposed switch investment of $458 per line, which does not reflect the removal of the non-usage sensitive costs as directed in Finding of Fact No. 10, is less than both AT&T's 2006 switch investment of $551 and Verizon's 2006 switch investment of $1,005 as shown on Public Staff Conwell Cross Examination Exhibit No. 1.

The Commission also concludes that, generally, when company-specific information is readily available, it is better practice to use such information.

A final area of contention between the parties concerns the switch investment amount reflected in MebTel's cost study for the Milton/Gatewood switch of $3.9 million, or $1,153 per access line. The CMRS Providers argued that the investment reflected for the Milton/Gatewood switch is "off the chart". The Commission notes that the $3.9 million figure for the Milton/Gatewood switch reflects the book cost of the switch that MebTel purchased from then-BellSouth in May of 2005. The Commission does not find that there is adequate or convincing

[1] Footnote 23 of witness Conwell's testimony details his calculation of $114 per line for the Mebane DCO switch. Footnote 24 details witness Conwell's calculation of $353 per line for the Gatewood switch and $153 per line for the Milton switch. However, a simple average derived by adding $114 + $353 + $153, divided by three switches, does not produce a figure of $143 per line.

[2] The Commission does acknowledge that the FCC used a small sample of information from rural carriers in its estimated switch costs in its *USF Inputs Order* (See Skrivan Cross Examination Exhibit No. 13).

evidence in the record to support any adjustment to the switch investment reflected in MebTel's cost study for the Milton/Gatewood switch.

Therefore, based upon the foregoing, the Commission finds that it is not appropriate to alter MebTel's proposed switch investment per line as proposed by the CMRS Providers. However, the Commission does note that, in Finding of Fact No. 7, the Commission has excluded the investment in the Mebane DMS switch from MebTel's cost study. The Commission therefore determines that MebTel's proposed total switch investment per line of $458 should be used; however, this figure should be adjusted based on the Commission's conclusions concerning usage sensitive switching costs discussed in Finding of Fact No. 10 herein below.

CONCLUSIONS

The Commission concludes that it is not appropriate to alter MebTel's proposed switch investment per line as proposed by the CMRS Providers. However, in Finding of Fact No. 7, the Commission excluded the investment in the Mebane DMS switch from MebTel's cost study. Therefore, the Commission agrees that MebTel's proposed total switch investment per line of $458 should be used, however, this figure should be adjusted based on the Commission's conclusions concerning usage sensitive switching costs discussed in Finding of Fact No. 10 herein below.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

ISSUE NO. 9 – MATRIX ISSUE NO. 19: What effective annual cost factor should be used for MebTel to compute switching annual costs per line?

POSITIONS OF PARTIES

RLECs: The RLECs stated that MebTel's position is that its cost study, including the annual cost factor of 30.5% used in that study, is consistent with the Commission's Guidelines for alternative cost studies by small RLECs. The RLECs recommended that the Commission find that an effective annual cost factor of 30.5% is to be used in computing MebTel's reciprocal compensation rate.

CMRS PROVIDERS: The CMRS Providers stated that they have agreed to accept MebTel's revised switching annual cost factor of 30.6%. **Commission Note:** MebTel's actual proposed annual cost factor is 30.5%. The Commission is assuming that the CMRS Providers are in agreement with the 30.5% annual cost factor proposed by MebTel.

PUBLIC STAFF: The Public Staff opined that the effective annual cost factor to be used for determining MebTel's cost is that which is produced using MebTel's alternative cost study factors.

DISCUSSION

The RLECs stated in their Proposed Order that MebTel's cost study, including the annual cost factor of 30.5% used in that study, is consistent with the Commission's Guidelines for alternative cost studies by small RLECs. The RLECs maintained that the CMRS Providers' position is that an effective annual cost factor of 30.1% should be multiplied times their proposed $143 per line switch investment to compute switching annual costs per line, which they say is only slightly lower than the effective annual cost factor of 30.5% reflected in the revised MebTel cost study produced in witness Skrivan's rebuttal testimony.

The RLECs noted that CMRS Providers witness Conwell proposed to further reduce MebTel's costs in his model by nominally accepting the annual charges from MebTel's cost study, meaning that he accepted that MebTel's costs are about 32% of the capital costs of MebTel's switching investment, but then he reduced MebTel's costs by over 90% and applied the same annual charge ratio to the reduced investment as MebTel applies to its actual investment. The RLECs asserted that this methodology leads witness Conwell to assert that it costs MebTel less than 10% as much to maintain theoretical central office equipment than it does to maintain MebTel's actual central office equipment. The RLECs stated that, in other words, while it appears as though witness Conwell is accepting MebTel's expenses when he has, in fact, reduced them by over 90%. The RLECs recommended that the Commission find this inappropriate, and conclude that an effective annual cost factor of 30.5% is to be used in computing MebTel's reciprocal compensation rate.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers noted in their Proposed Order that they have agreed to accept MebTel's revised switching annual cost factor of 30.6%.

The CMRS Providers maintained in their Post-Hearing Brief that, as stated by witness Conwell in his testimony, annual cost factors are ratios of the return requirement, income taxes, and operating expenses to total investment. The CMRS Providers stated that, for example, the capital cost factor is the ratio of the sum of return, income taxes, and depreciation to Central Office Equipment switching investment. The CMRS Providers noted that the factors are used to determine the annual costs incurred in providing transport and termination. The CMRS Providers stated that MebTel has proposed an annual cost factor of 30.60% and that the CMRS Providers have proposed an annual cost factor of 30.10%.

The CMRS Providers stated that MebTel's original cost study proposed an annual cost factor of 32%. The CMRS Providers maintained that their witness Conwell proposed to lower that factor to 30.10%, which was the original 32% annual cost factor with two adjustments. The CMRS Providers maintained that, for the first adjustment, the cost of capital was reduced from 11.25% to 10.10% to comply with Guideline No. 4 of the Commission's alternative cost study Guidelines. The CMRS Providers noted that, for the second adjustment, customer operations expenses, representing 0.9 percentage points of the original annual cost factor, were also removed, because those expenses were attributable to retail and interexchange access services and therefore not recoverable in transport and termination rates. The CMRS Providers asserted that the second adjustment was made to comply with Guideline Nos. 1 and 7.

The CMRS Providers maintained that, as a result of witness Conwell's proposal, MebTel has modified its proposed annual cost factor to 30.6%, which is a figure the CMRS Providers will accept.

The Public Staff stated in its Proposed Order that there is little difference between the 30.5% and the 30.1% proposed by MebTel and the CMRS Providers, respectively. The Public Staff stated that MebTel witness Skrivan testified that the customer operations expense, which witness Conwell excluded, included no retail costs. The Public Staff maintained that, instead, it included costs associated with taking orders, billing, and collecting from interconnected carriers such as ALLTEL and Cingular. The Public Staff maintained that, although the expenses are listed as "Customer Operations Expense", the expenses are not retail. The Public Staff noted that the expenses deal with MebTel's wholesale customers such as IXCs and wireless carriers. The Public Staff recommended that the Commission find that MebTel has appropriately included this cost in its alternative cost study.

The Public Staff further asserted that the factor used by MebTel to calculate the state income tax understates the state income tax applicable to MebTel. The Public Staff stated that the study contains no costs associated with regulatory fee recovery. The Public Staff stated that it believes that MebTel should ensure it uses the appropriate tax and regulatory fee rates. Further, the Public Staff recommended that the Commission find that, consistent with the Commission's Finding of Fact No. 9 in its December 10, 1998, Order in Docket No. P-100, Sub 133d, the reasonable and appropriate tax rates and regulatory fee for use in the cost study are: federal income tax rate, 35%, state income tax rate, 6.9%, and regulatory fee, 0.09%.

The Public Staff proposed that the Commission conclude that the appropriate annual cost factor is that which is determined through the use of MebTel's alternative cost study, including the Customer Operations Expense, and correcting the factor used to determine the amount of state income tax.

The Commission notes that the CMRS Providers agreed in their Proposed Order and Post-Hearing Brief to accept MebTel's proposed annual cost factor.[1] Since the RLECs and the CMRS Providers are in agreement with the use of the 30.5% annual cost factor, the Commission finds it appropriate to adopt this rate for use in MebTel's alternative cost study.

CONCLUSIONS

The Commission concludes that an annual cost factor of 30.5% should be used for MebTel to compute switching annual costs per line.

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[1] The CMRS Providers stated that MebTel's proposed annual cost factor is 30.6%. However, MebTel's actual proposed annual cost factor is 30.5%. The Commission is assuming that the CMRS Providers are in agreement with the 30.5% annual cost factor proposed by MebTel.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

ISSUE NO. 10 – MATRIX ISSUE NO. 20: Should MebTel's transport and termination rate recover its nonusage sensitive switching costs?

ISSUE NO. 11 – MATRIX ISSUE NO. 21: If not, what percentage of total switching annual costs per line (18 and 19) should be recovered by MebTel's transport and termination rate?

POSITIONS OF PARTIES

RLECs: Guideline No. 3 requires the RLECs to develop usage based rates, but it does not require the RLECs to develop rates based on usage sensitive costs or in accord with other TELRIC regulations. The Commission's alternative cost study Guidelines do not require that all of an RLEC's central office investments except for trunking equipment be excluded from the RLECs' cost studies or from the calculation of an appropriate reciprocal compensation rate for each RLEC. Since the RLECs believe that MebTel's transport and termination rate should recover its nonusage sensitive switching costs, they believe that Matrix Issue No. 21 is moot.

CMRS PROVIDERS: MebTel is not allowed to recover nonusage sensitive switching costs. TA96, FCC regulations, and previous Commission orders allow the recovery of only usage-sensitive switching costs in transport and termination rates. Those include only costs for (1) trunking equipment; and (2) the switch matrix. MebTel's continuing property records indicate that 38% of the switching investment in the Mebane DCO switch is for trunking equipment and the switch matrix. The remainder of the investment is for lineside equipment used to terminate subscriber loops and other items not connected to the switch matrix or trunking equipment. Therefore, MebTel should recover 38% of its total annual switching investment and costs per line in transport and termination rates.

PUBLIC STAFF: The appropriate amount of switch investment should exclude the line-port, or non-traffic sensitive, portion of MebTel's Milton, Gatewood, and Mebane DCO switches.

DISCUSSION

The RLECs stated in their Proposed Order that the CMRS Providers believe that Guideline No. 1 requires that cost data reflect only the direct costs associated with the transport and termination of traffic. The RLECs noted that the CMRS Providers asserted that direct switching costs are the costs caused by terminating a minute of use of mobile-to-land traffic, which the CMRS Providers contend are the usage-sensitive costs of the switch. The RLECs asserted that the CMRS Providers maintained that Guideline No. 3, which requires rates to be usage based, should be construed to mean that costs must be usage-sensitive.

The RLECs further stated that the CMRS Providers argued that Section 252(d) of TA96 allows the RLECs to recover only the additional costs of transporting and terminating CMRS traffic. The RLECs maintained that the CMRS Providers argued that, under the FCC's TELRIC rules, this additional cost standard allows the recovery of only usage-sensitive costs and that the RLECs cannot be exempted from this standard.

The RLECs maintained that, in addition to proposing that the Commission reject MebTel's data and instead use inputs from an FCC proceeding concerning high cost support for nonrural ILECs, CMRS Providers witness Conwell then proposed to discard a majority of the reduced costs he would use from the *USF Inputs Order*, based on his argument that most switching costs are not usage sensitive. The RLECs noted that witness Conwell argued that, when the Public Staff recommended that the RLECs' alternative cost studies should develop usage-based rates, what the Public Staff really meant to say was that reciprocal compensation rates should be based on usage sensitive costs. The RLECs maintained that, based on that contention, witness Conwell argued that the Commission should exclude all switch costs except for trunking, even including the so-called getting started costs of a switch, including the switch matrix and the processor.

The RLECs asserted that the approach advocated by witness Conwell is inconsistent with the Commission's past rulings on switch expense. The RLECs maintained that, specifically, in TELRIC proceedings to establish UNE rates for large ILECs like AT&T and Embarq, the Commission has not excluded the switch investments that the CMRS Providers would now have the Commission exclude from the cost studies of these small companies, which are a fraction of the size of an ILEC like AT&T or Embarq. The RLECs opined that, implicit in the Commission's orders establishing UNE prices for large ILECs, such as the orders concerning AT&T UNEs in Docket No. P-100, Sub 133d, is the recognition by the Commission that, even in a TELRIC proceeding, the switch investment cost to be included in developing rates includes a significant portion of the switch cost. The RLECs stated that even witness Conwell conceded that the Commission has not taken the approach he now advocates for the RLECs in the past dockets involving TELRIC-based UNE pricing for the largest ILECs.

The RLECs maintained that, in addition, the FCC's *USF Inputs Order* used 70% of switching investment for the development of non-rural USF costs. The RLECs stated that the FCC's *MAG Order*[1] allowed rural carriers to treat 70% of switching costs as usage sensitive. The RLECs noted that witness Conwell acknowledged this result. The RLECs asserted that the *MAG Order* applied to more than one carrier; it was a decision which applied to every rate-of-return carrier in the country. The RLECs argued that, in that Order, the FCC adopted a presumption for small carriers that only 30% of local switching costs were non-traffic sensitive and incorporated it into its regulations. The RLECs also noted that other State commissions have adopted traffic-sensitive switching cost recovery rates for reciprocal compensation for Regional Bell Operating Companies (RBOCs) in TELRIC proceedings from 62% to 70%.

The RLECs stated that the Minnesota Public Utilities Commission's decision cited by the CMRS Providers in this docket was made with respect to UNE-P pricing for Qwest, a non-rural carrier. The RLECs asserted that the Minnesota decision did not concern reciprocal compensation pricing for a rural carrier. Likewise, the RLECs maintained that, in the Illinois Commerce Commission's decision cited by witness Conwell, the Illinois Commerce Commission did not specifically find that rural carriers' switches were non-traffic sensitive. Rather, the RLECs argued, the Illinois Commerce Commission found that the rural carriers did not present evidence that would allow that Commission to reach a decision different from the

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[1] In the Matter of Multi-Association Group (MAG) Plan for Regulation of Interstate Services of Non-Price Cap Incumbent Local Exchange Carriers and Interexchange Carriers, FCC 01-304, released November 8, 2001.

one it reached on the usage-sensitive nature of switching costs for SBC in a previous UNE-P pricing docket.

The RLECs contended that, in both the Minnesota and Illinois decisions, it is important to note that the involved RBOCs (Qwest and SBC) were still able to recover their switching costs from competitive carriers through the UNE-P rates set by those commissions. However, the RLECs noted, they recovered their switching costs on a per-line basis rather than on a per MOU basis. The RLECs argued that, also, the Minnesota and the original Illinois decisions were made in light of the testimony of Qwest and SBC witnesses that their switches were priced solely on a per-line basis in the price the carriers paid vendors for their switches. The RLECs further noted that witness Conwell used the HAI 5.0a, a TELRIC cost model, as a source of cost data that he considered to be appropriate in substituting his calculations for those of the RLECs. The RLECs maintained that witness Conwell conceded that, even though he did not propose to use this piece of data, the HAI 5.0a model assigns 70% of ILEC switch costs as being usage sensitive. The RLECs asserted that witness Conwell acknowledged that his recommendation that the Commission disallow all but 10% of the RLECs' switch costs was inconsistent with the HAI 5.0a model.

The RLECs maintained that witness Conwell depicts the Public Staff's cost study Guidelines as being very similar to, or essentially the same as, the FCC's requirements for the determination of TELRIC and forward-looking economic costs in §51.505. The RLECs noted that witness Conwell argued that usage based rates means the same thing as traffic sensitive costs. The RLECs opined that the Guideline calling for usage-based rates means simply that the rates must vary based on usage; it does not mean that rates must be based on traffic sensitive costs. The RLECs argued that, had the Public Staff intended for the cost study Guidelines to require pricing based on traffic sensitive costs, the Public Staff, which has been an active participant in many UNE proceedings and is familiar with the FCC's TELRIC rules, would have said so.

The RLECs argued that, as shown by MebTel witness Skrivan, the issues with defining costs in this fashion include establishing the time frames, technology, and assumptions associated with the underlying determinations. The RLECs maintained that economists discuss Long Term Incremental Costs as being relevant when the time frame dictates that all costs are variable. The RLECs asserted that, under this definition, all costs are traffic sensitive. The RLECs noted that witness Skrivan pointed out that if, in the long run, there is no traffic then there are no costs. The RLECs argued that this could support the conclusion that all costs are traffic sensitive.

The RLECs recommended that the Commission reject witness Conwell's arguments that there are deficiencies in the RLECs' cost studies, based on his application of FCC TELRIC regulations and/or various state commission rulings made in TELRIC proceedings or with regard to TELRIC standards. In addition, the RLECs proposed that the Commission find that Guideline No. 3, which provides that the rates for transport and termination should be usage based, does not require that those rates be based on usage-sensitive costs determined in accordance with the FCC's TELRIC regulations. The RLECs opined that the Guidelines do not require that all of an RLEC's central office investments except for trunking equipment be excluded from the RLECs' cost studies or from the calculation of an appropriate reciprocal compensation rate for each RLEC.

The RLECs did not provide any additional discussion on this issue in their Post-Hearing Brief.

The CMRS Providers maintained in their Proposed Order that TA96 specifies that ILECs may recover in transport and termination rates only the additional costs of terminating such calls (See Section 252(d)(2)(A)(ii)). The CMRS Providers asserted that the FCC has interpreted this additional cost standard as limiting recovery to usage-sensitive costs. The CMRS Providers noted that the *Modification Order* specifies that the rates for transport and termination of traffic should be usage based. The CMRS Providers further noted that Paragraph 1063 of the FCC's *First Report and Order* states that usage-based charges should be limited to situations where costs are usage sensitive.

The CMRS Providers argued that the Commission found in its UNE pricing docket for AT&T that the getting started costs of a switch are usage-sensitive. The CMRS Providers maintained that getting started costs are incurred for capacity that is shared among subscribers and are often referred to as switch matrix costs. The CMRS Providers noted that they include the costs of the central processor, core memory, and switch network. The CMRS Providers agreed that the trunking costs of a switch are also usage-sensitive. The CMRS Providers argued that, however, the FCC has made it clear that the lineside costs of equipment used to terminate subscriber access lines are non-usage sensitive and, therefore, not recoverable in transport and termination rates (See Paragraph 1057 of the *First Report and Order*).

The CMRS Providers asserted that MebTel's continuing property records (See Skrivan Cross-Examination Exhibit No. 14) give a clear breakdown of the lineside, trunkside, and switch matrix investments for the Mebane DCO switch. The CMRS Providers maintained that 16% of the investment is for trunking equipment, and 22% is for the switch matrix. The CMRS Providers stated that MebTel has not disputed these figures. The CMRS Providers recommended that the Commission conclude that MebTel's transport and termination rate should recover 38% of MebTel's total switching annual cost per line.

The CMRS Providers asserted in their Post-Hearing Brief that MebTel's transport and termination rate should not recover its non-usage sensitive switching costs. The CMRS Providers argued that the Commission has never ruled that non-usage sensitive switching costs are recoverable through transport and termination rates. The CMRS Providers maintained that MebTel is seeking to recover all of its annual switching costs per line, even the non-usage sensitive costs. The CMRS Providers opined that this is inconsistent with the cost study submitted by Randolph in this proceeding, as well as federal law, the Commission's *Modification Order*, and the Commission's previous AT&T *UNE Order*. The CMRS Providers asserted that there is no justification for allowing MebTel to recover non-usage sensitive switching costs.

Witness Conwell explained on cross examination that:

> . . . the Public Staff had specified two guidelines: The first one was that only direct costs can be included. When you take that guideline, recognizing that usage-sensitive costs are the only direct costs of switching as it relates to transport and termination. That means for Guideline [No.] 3 that the usage-based cost of switching would be the usage-sensitive cost of switching. Those two guidelines are hand-in-glove with one another. That was the basis of my application of the guidelines.

The Public Staff stated in its Proposed Order that only the traffic sensitive investment in MebTel's switches should be reflected in its study. The Public Staff maintained that the traffic sensitive investment is that part of the switch that excludes the investment in the line port.

The Public Staff noted that the evidence in the record is clear regarding the amount of investment associated with MebTel's Mebane DCO switch. However, the Public Staff asserted that the record is unclear as to the amount of switching investment MebTel has that should be considered to be non-traffic sensitive. The Public Staff stated that witness Conwell testified that the line port investment associated with the Mebane DCO switch was 57% of the total investment for that switching. Therefore, the Public Staff opined that the Commission can conclude that 43% of the investment in the Mebane DCO switch can be considered to be the traffic sensitive portion of the switch.

The Public Staff asserted that, unfortunately, the determination of the traffic sensitive portions of the Milton and Gatewood switches is not as simple. The Public Staff noted that witness Skrivan testified that these switches were recently purchased from AT&T and that the continuing property records that are used to assign plant to various categories are not available. Thus, the Public Staff maintained that the Commission cannot simply assume that the characteristics of the Milton and Gatewood switches are similar to MebTel's Mebane DCO switch.

The Public Staff asserted that another distinction between the Mebane DCO switch and the Milton and Gatewood switches is the number of lines served. The Public Staff noted that the Milton switch only serves 14% of the lines served by the Mebane DCO switch, while the Gatewood switch only serves 16%. The Public Staff maintained that a switch serving only a few customers is unlikely to have the same characteristics as one that serves many customers, as evidenced by witness Conwell's Exhibit WCC-6 showing Randolph's switch to only include 19% of its investment as pertaining to line ports. The Public Staff stated that, thus, it seems unlikely that the Milton and Gatewood switches have the same characteristics as a larger one such as the Mebane DCO switch.

The Public Staff noted that Randolph witness Schoonmaker provided additional evidence regarding the potion of a switch that can be considered non-traffic sensitive. The Public Staff maintained that witness Schoonmaker testified that the FCC allows rural carriers to treat 70% of switching costs as traffic sensitive and that the FCC has even incorporated this approximation into its rules. The Public Staff believes that this is a reasonable approximation of the traffic sensitive portion of the Milton and Gatewood switches.

The Public Staff recommended that the Commission find that MebTel's alternative cost study should only include the traffic sensitive portions of the Milton, Gatewood, and Mebane DCO switches.

The Commission notes that Guideline No. 1 states, as follows: "The cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic" [emphasis added]. Guideline No. 3 states, as follows: "The rates for transport and termination of traffic should be usage based."

The RLECs interpret these two Guidelines to mean that the transport and termination rates must vary based on usage and are, therefore, proposing that the Commission include 100% of MebTel's switching investment in MebTel's cost study. The CMRS Providers and the Public Staff assert that usage-based is synonymous with traffic-sensitive. The CMRS Providers and the Public Staff agree that the Commission should only reflect the traffic-sensitive portion of MebTel's switching investment in the cost study, but they do not agree on what is the appropriate level of traffic-sensitive switching investment to include. The Commission also notes that Randolph reflected only traffic-sensitive switching investment in its cost study and did not interpret the Commission's Guidelines in the same manner as did MebTel, i.e., that rates must vary based on usage and that nonusage sensitive costs should be recovered in reciprocal compensation rates.

The first question to be addressed by the Commission is whether the Guidelines require that only usage sensitive switching costs should be recovered in MebTel's transport and termination rate. The Commission believes that the correct interpretation is that advocated by the CMRS Providers and the Public Staff, i.e., that only usage sensitive switching costs should be recovered. The Commission agrees with CMRS Providers witness Conwell that Guideline Nos. 1 and 3 need to be read together to indicate that direct costs, which would only be the usage sensitive costs, should be recovered and that only usage sensitive costs be reflected in the alternative cost studies.

Matrix Issue No. 21 (If not, what percentage of total switching annual costs per line should be recovered by MebTel's transport and termination rate?) also needs to be addressed since the Commission is finding that only usage sensitive costs should be recovered. The record of evidence provides that various sources have used or recommended various percentages to reflect usage sensitive switching costs, as follows:

Source	Usage Sensitive Switching Percentage
HAI 5.0a	Default of 70%
HAI 5.3	Default of 0%
FCC's *MAG Order*	70%
CMRS Providers	38%
Witness Skrivan – MebTel	100%
Witness Schoonmaker – Randolph	70%
Commission in AT&T UNE docket	More than 10%
Other state Commissions in TELRIC dockets	62% to 70%
Public Staff – Mebane DCO switch	43%
Public Staff – Milton and Gatewood switches	70%

The CMRS Providers have recommended that the Commission conclude that 38% of MebTel's total switching annual cost per line should be recovered in its transport and termination rate, which consists of 22% getting started costs or switch matrix costs and 16% of trunking costs[1]. The Public Staff recommended that, for the Mebane DCO switch, the Commission conclude that 43% of the switch investment is usage sensitive (100% - 57% line side port costs). The Public Staff recommended that, since the Milton and Gatewood switches serve significantly fewer lines than the Mebane DCO switch, the Commission use a figure of 70% which has been allowed by the FCC for rural carriers.

The Commission believes that, generally, when company-specific information is readily available, it is better practice to use such information. The Commission notes that, although the Public Staff advocated using a 70% figure for the Milton and Gatewood switches, there is no evidence in the record which compares the size of the rural carriers to which the FCC's 70% figure was applied and the size of the Mebane DCO, Milton, and Gatewood switches. Therefore, the Commission believes it is most reasonable to apply the known percentage for usage sensitive costs for the Mebane DCO switch of 38% as supported by MebTel's continuing property records for the Mebane DCO switch to MebTel's Milton and Gatewood switches.

CONCLUSIONS

The Commission concludes that MebTel's transport and termination rate should not recover its nonusage sensitive switching costs. Further, the Commission concludes that 38% of total switching annual costs per line should be recovered by MebTel's transport and termination rate. The Commission addresses the appropriate level of usage sensitive switching costs to be included in Randolph's and Ellerbe's alternative cost studies in Finding of Fact No. 17 hereinbelow.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

ISSUE NO. 12 – MATRIX ISSUE NO. 22: Did Randolph's cost study use appropriate cost data?

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[1] The percentages used were based on information reflected in the continuing property records for the Mebane DCO switch. The CMRS Providers simply recommend that the Commission apply the same percentages from the Mebane DCO switch to the Milton and Gatewood switches.

TELECOMMUNICATIONS – MISCELLANEOUS

POSITIONS OF PARTIES

RLECs: Yes. The RLECs argued that Randolph's use of cost data developed by the National Exchange Carriers Association (NECA) in Randolph's cost study are consistent with the Commission's alternative cost study Guidelines and that its data are appropriate.

CMRS PROVIDERS: No. The CMRS Providers argued that Randolph's use of data from NECA average schedule companies was inappropriate for at least three reasons, as follows:

(1) the data are based on embedded (historical) costs rather than forward-looking costs;

(2) Randolph's use of the NECA data creates the equivalent of an interstate "access" rate. FCC regulations prohibit Randolph from charging access rates for the transport and termination of wireless traffic; and

(3) Randolph has used the NECA data and formulas in a manner that prevents effective analysis.

PUBLIC STAFF: The Public Staff stated that Randolph's cost study is generally consistent with the Commission's alternative cost study Guidelines that were established in Docket No. P-100, Sub 159. The Public Staff maintained that, however, the average schedule formulas and local switch support formulas should reflect the most recent formulas approved by the FCC.

DISCUSSION

The RLECs stated in their Proposed Order that Randolph's use of cost data developed by NECA in its cost study is consistent with the Commission's alternative cost study Guidelines and that its data are appropriate. The RLECs noted that Randolph's evidence established that NECA's annual cost study is filed with the FCC. The RLECs maintained that that study involves selecting a statistical sample of both cost and average schedule companies and collecting accounting and demand data from the selected companies. The RLECs maintained that, while NECA's methodology is used to develop access rates, the functions and facilities Randolph uses to terminate a minute of CMRS originated traffic are essentially identical to the functions and facilities Randolph uses to terminate a minute of interstate toll traffic. The RLECs noted that CMRS Providers witness Conwell conceded that this is the case. The RLECs asserted that NECA's traffic-sensitive formulas were used as a basis for Randolph's cost study because these formulas are well documented, easily obtainable, and produce a reasonable surrogate of Randolph's costs since they are developed using actual costs of similarly-situated rural ILECs. The RLECs stated that, furthermore, NECA's cost formulas undergo regular scrutiny by the FCC's staff. The RLECs also argued that components of NECA's traffic-sensitive formulas that did not relate to transport and termination were not utilized in Randolph's reciprocal compensation cost study, such as the special access formulae and the equal access cost recovery formula.

The RLECs noted that witness Conwell criticized Randolph's alternative cost study because the methodology used to develop Randolph's rates is the same methodology used to calculate interstate access rates. The RLECs stated that witness Conwell's testimony suggests that Randolph is proposing to charge Cingular and ALLTEL its tariffed access charges. The RLECs maintained that the reciprocal compensation rate proposed by Randolph is not equal to either Randolph's intrastate or interstate access rates. The RLECs asserted that, while Randolph developed its rates based on NECA's average schedule formulas, those formulas were altered to provide results consistent with the Commission's alternative cost study Guidelines.

The RLECs noted that witness Conwell also argued that FCC Rule 51.515(a)[1] is applicable to the development of reciprocal compensation rates. However, the RLECs stated, it appears that the FCC's rule cited by witness Conwell in his argument is not applicable, and would not apply even if this was a TELRIC proceeding. The RLECs maintained that, specifically, §51.515(a) is in Subpart F of Part 51. The RLECs stated that, according to §51.501(a), Subpart F only applies to the pricing of network elements, interconnection, and methods of obtaining access to unbundled network elements, including physical collocation and virtual collocation.

The RLECs opined that the present dockets were opened to establish interconnection agreements, including reciprocal compensation rates, to which Subpart H of Part 51 applies. The RLECs asserted that, as stated in §51.701(a), Subpart H applies to "reciprocal compensation for transport and termination of telecommunications traffic between LECs and other telecommunications carriers." The RLECs maintained that, while the FCC's reciprocal compensation rules in Subpart H require consistency with specific provisions in Subpart F (§51.505, §51.509, and §51.511), they do not require consistency with §51.515. The RLECs argued that, in addition, there is not a similar provision regarding the use of access charges in Subpart H. The RLECs recommended that the Commission find that witness Conwell's repeated citations to §51.515(a) and arguments that Randolph is proposing to bill access charges to Cingular and ALLTEL to be unpersuasive.

The RLECs asserted that Randolph developed a forward-looking cost study to the extent practicable, consistent with the Commission's alternative cost study Guidelines. The RLECs maintained that, if there are aspects of Randolph's cost study that the Commission deems to be reflective of embedded costs, it is fully consistent with the alternative cost study Guidelines to allow such costs. The RLECs argued that allowance of use of some portion of such costs is also consistent with the Commission's overarching policy decision to suspend any obligation for the RLECs to perform TELRIC studies. The RLECs stated that it was clearly the position of the Public Staff, as adopted by the Commission, that the RLECs who petitioned for modification of any TELRIC requirement should be afforded some latitude in being allowed to provide nonTELRIC alternative cost studies. The RLECs asserted that, otherwise, the Commission's Section 251(f)(2) modification of any obligation to perform TELRIC studies is rendered meaningless.

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[1] §51.515(a) states: "Neither the interstate access charges described in part 69 of this chapter nor comparable intrastate access charges shall be assessed by an incumbent LEC on purchasers of elements that offer telephone exchange or exchange access services."

The RLECs recommended that the Commission find that the cost data used by Randolph were easily obtainable, verifiable, and reflected only direct costs associated with the transport and termination of traffic, as required by Guideline No. 1. The RLECs further recommended that the Commission conclude that Randolph's cost study used appropriate cost data and its proposed rates are not based on Randolph's access rates.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that Randolph employed embedded data in its cost study. The CMRS Providers stated that, prior to conducting the study for Randolph, Randolph witness Schoonmaker prepared an analysis of various cost study options. The CMRS Providers noted that witness Schoonmaker's description of the option ultimately chosen by Randolph specifically stated that there would be no forward-looking element to the costs. The CMRS Providers argued that, in addition, during the hearing, witness Schoonmaker conceded that the Randolph cost study is based on embedded costs but does reflect forward-looking demand units. The CMRS Providers stated that, under further questioning, witness Schoonmaker admitted that the data used in Randolph's study does not represent Randolph's cost to purchase new switches.

The CMRS Providers argued that the Commission should find that the use of the FCC switch cost data from the FCC's *USF Inputs Order* is practicable and feasible. The CMRS Providers believe that the Commission should conclude that Randolph's use of embedded cost data from NECA average schedule companies does not comply with the Commission's alternative cost study Guidelines as outlined in the Commission's *Modification Order*. The CMRS Providers stated that they were unable to determine how the formulas work and could not determine how Randolph calculated its proposed rate.

The CMRS Providers recommended that the Commission conclude that Randolph's transport and termination rate must be computed based upon the methodology submitted and used by MebTel. Further, the CMRS Providers asserted that the Commission should order certain specific inputs and assumptions to be used in computing Randolph's transport and termination rate, consistent with the changes the CMRS Providers recommended to the MebTel study and also consistent with other recommendations pertaining to Randolph.

The CMRS Providers stated in their Post-Hearing Brief that the NECA average schedule data are used to compute interstate access rates for certain rural carriers. The CMRS Providers asserted that FCC regulations (specifically, §51.515(a)) prohibit Randolph and other RLECs from charging access rates for the transport and termination of wireless traffic. The CMRS Providers maintained that the NECA average schedule formulae employed by witness Schoonmaker in the Randolph cost study are the basis of RLEC compensation for interstate access charges and therefore reflect the cost data and methodologies used to develop interstate access charges per FCC Part 69.

The CMRS Providers argued that the Commission's *Modification Order* did not purport to affect FCC Rule 51.515(a) prohibiting the use of interstate access charges. The CMRS

Providers noted that, instead, the *Modification Order* directed the RLECs to conduct alternative cost studies utilizing the Guidelines recommended by the Public Staff. The CMRS Providers stated that those Guidelines require that the studies not include revenues to subsidize other services. The CMRS Providers also maintained that the NECA average schedule formulae reflect embedded costs and result in rates that exceed forward-looking costs. Thus, the CMRS Providers opined, the Randolph cost study is inconsistent with both FCC regulations and the Commission's *Modification Order*.

The CMRS Providers also asserted that witness Schoonmaker's direct testimony contains as Exhibit RCS-1 a document entitled "NECA Average Schedule Formulas Proposed for 7/1/2006". The CMRS Providers stated that the Exhibit is three pages long and purports to demonstrate the various formulae used in computing Randolph's proposed transport and termination rate. However, the CMRS Providers argued that Exhibit RCS-1 is virtually impenetrable; that they cannot determine exactly, or even approximately, how Randolph's proposed rate was calculated; and that witness Schoonmaker's testimony provides no real insight in that regard.

For example, the CMRS Providers stated that they cannot find a proposed switching investment per line anywhere in witness Schoonmaker's testimony. The CMRS Providers asserted that the same is true for the usage-sensitive percentage assumed for local switching, the cost of interoffice cable per foot, and the assumed investment for transmission equipment. The CMRS Providers opined that there is simply no way to analyze what Randolph has done.

The CMRS Providers stated that assume, for example, that the Commission were to agree with the CMRS Providers that Randolph should not use embedded, average schedule company data for determining switching costs. The CMRS Providers maintained that, if the Commission were to require Randolph to use company-specific, forward-looking switching cost data, there appears to be no way to insert such costs into the material provided by witness Schoonmaker. The CMRS Providers stated that the same is true for every other important variable – cable costs, transmission equipment costs, annual cost factors, and the like.

The CMRS Providers argued that, because Randolph's study cannot be analyzed in any meaningful manner, it should be rejected *in toto* and that the Commission should adopt the rate proposed by CMRS Providers witness Conwell, computed in a transparent manner with publicly available and company-specific data.

The CMRS Providers asserted that, in attempting to justify Randolph's use of NECA average schedule data, witness Schoonmaker claims that forward-looking costs were used in the Randolph alternative cost study to the extent it was practicable and feasible to do so. The CMRS Providers maintained that this claim, however, is refuted by witness Schoonmaker's frank admission at the hearing that the Randolph study, based on NECA average-schedule data, does not represent Randolph's cost to purchase new switches.

The CMRS Providers argued that, in effect, Randolph is claiming that it should be allowed to use NECA average-schedule data because the use of company-specific data was not practicable and feasible. The CMRS Providers opined that the fault with this argument, however, is demonstrated by the MebTel cost study. The CMRS Providers maintained that, although the MebTel study contains errors, such as the use of nonusage sensitive switching costs, all of the information in the MebTel study is company-specific. The CMRS Providers stated that MebTel did not find it burdensome or impracticable to use its own data in proposing a transport and termination rate. The CMRS Providers stated that, moreover, the use of company-specific data for Randolph would not have been burdensome because Randolph has produced such data in response to specific CMRS Providers data requests. The CMRS Providers asserted that Randolph has simply made no showing that the use of company-specific data was impracticable or burdensome.

The Public Staff stated in its Proposed Order that, while the study performed by witness Schoonmaker may not be perfect, it is reasonable and falls within the Guidelines adopted by the Commission in Docket No. P-100, Sub 159. The Public Staff maintained that, however, it is concerned that the NECA formulas used by witness Schoonmaker will be replaced with different formulas after June 30, 2007, since these formulas are updated annually. The Public Staff noted that it is aware that the Local Switching Support (LSS) formula that witness Schoonmaker used was valid for the calendar year 2006. The Public Staff asserted that it would be appropriate for Randolph to resubmit its study, reflecting the most recent NECA and LSS formulas. The Public Staff argued that these changes will help to ensure that the reciprocal compensation rates for Randolph are forward-looking. The Public Staff recommended that the Commission conclude that Randolph's cost study is consistent with the Commission's alternative cost study Guidelines that were established in Docket No. P-100, Sub 159, except that the average schedule formulas and local switch support formulas should reflect the most recent formulas approved by the FCC.

The Commission notes that Randolph used cost data developed by NECA in its reciprocal compensation cost study that was developed using <u>actual costs</u> of <u>similarly-situated rural ILECs</u>. The CMRS Providers have proposed that the Commission require Randolph to use the cost study methodology outlined by witness Conwell that used certain default input values from the HAI 5.0a model, some Randolph-specific data from its cost study and data request responses, and some data from MebTel's cost study. The Public Staff has stated that Randolph's cost study is generally consistent with the Commission's alternative cost study Guidelines, however, that the study should be updated to reflect the most recent formulas approved by the FCC.

The Commission notes that the seven Guidelines required by the Commission in its *Modification Order* to be used by the RLECs when conducting their alternative cost studies are as follows:

1. The cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic.

2. The cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network to the extent practicable.

3. The rates for transport and termination of traffic should be usage based.

4. The capital costs and structure should reflect the cost and structure approved by the Commission in previous decisions in Docket No. P-100, Sub 133d.

5. Depreciation should reflect the economic lives and net salvage values within the ranges established by the FCC.

6. The study should include a reasonable allocation of common costs to be added to direct costs.

7. The study should not include retail costs, opportunity costs, or revenues to subsidize other services.

In this proceeding, the CMRS Providers have outlined three specific criticisms of Randolph's proposed cost study, as follows:

(1) the data are based on embedded (historical) costs rather than forward-looking costs;

(2) Randolph's use of the NECA data creates the equivalent of an interstate "access" rate. FCC regulations prohibit Randolph from charging access rates for the transport and termination of wireless traffic; and

(3) Randolph has used the NECA data and formulas in a manner that prevents effective analysis.

The CMRS Providers basically dispute that Randolph's proposed alternative cost study is in compliance with Guideline Nos. 1 and 2 as outlined in the Commission's *Modification Order*.

First, the CMRS Providers asserted that Randolph's cost data are based on embedded costs rather than forward-looking costs. The CMRS Providers argued that Randolph's data do not represent Randolph's cost to purchase new switches, but reflect embedded costs as reported to NECA.

The Commission notes that Guideline No. 1 states that the cost data should be easily obtainable, verifiable, and reflect only the direct costs associated with the transport and termination of traffic. The Commission determines that use of NECA cost data as employed by Randolph in its costs study is not inconsistent with this Guideline. The Commission determines that the evidence of record shows that NECA data are easily obtainable and verifiable, and, therefore, in compliance with Guideline No. 1.

The Commission further notes that Guideline No. 2 states that the cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network to the extent practicable. The record shows that Randolph has 4,400 access lines. The Commission's *Modification Order* specifically noted that TELRIC cost studies would be unduly economically burdensome to the RLECs and that granting relief from producing TELRIC cost studies is consistent with the public convenience and necessity. By using NECA cost data, Randolph used surrogate cost data as allowed under Guideline No. 2. In addition, the

Commission concludes that use of such data is in compliance with the remainder of Guideline No. 2 in that it is forward looking and reflects an efficient network to the extent practicable. The Commission concludes that the *Modification Order* did not require the RLECs to obtain a vendor switch quote. The Commission is persuaded by the evidence of record that obtaining a switch quote from a vendor is not practicable for purposes of this proceeding. Further, the Commission concludes that the *Modification Order* did not prohibit the use of embedded costs in alternative cost studies. Therefore, the Commission finds that Randolph's use of NECA cost data which reflect embedded costs of similarly-situated RLECs is in compliance with the Commission's *Modification Order* and appropriate.

The CMRS Providers' second criticism of Randolph's cost study is that Randolph's use of the NECA data creates the equivalent of an interstate "access" rate. However, as the record notes, although the NECA methodology is used to develop access rates, Randolph's proposed reciprocal compensation rate in this proceeding is not equal to either its interstate or intrastate access rates. Witness Conwell stated during cross-examination that he was not contending in this proceeding that Randolph has proposed to charge either its interstate or intrastate access rate as a reciprocal compensation rate. Therefore, the Commission does not find merit in the CMRS Providers' argument in this regard.

The CMRS Providers' final criticism of Randolph's cost study is that Randolph has used the NECA data and formulas in a manner that prevents effective analysis. The CMRS Providers maintained that they were unable to determine how the formulas work. The CMRS Providers also asserted that they cannot determine exactly, or even approximately, how Randolph's proposed rate was calculated, and asserted that witness Schoonmaker's testimony provides no real insight in that regard.

The Commission notes that witness Schoonmaker provided evidence consisting of 21 pages of direct testimony, 24 pages of rebuttal testimony, and several schedules that explain Randolph's alternative cost study. In addition, the cross examination of witness Schoonmaker during the hearing provides further insight into Randolph's cost study. The Commission notes that Exhibit RCS-1 provides the NECA formulas used by witness Schoonmaker in Randolph's cost study. By following the formulas used and the information provided on Exhibit RCS-1, the Commission has been able to recreate the figures shown on Exhibit RCS-2 for Central Office Basic, Access Line Factor, Central Office Formula, and Traffic Sensitive Central Office. The Commission also has been able to calculate the Traffic Sensitive Cost Per Minute of Use of $0.01918 proposed by witness Schoonmaker in Exhibit RCS-4, as follows:

1.	Traffic Sensitive Settlement - ROR Adjusted Exhibit RCS-4, Line 30	$ 31,267.00
2.	Projected Monthly LSS Revenue Exhibit RCS-4, Line 35	$ 17,707.00
3.	Traffic Sensitive Cost Line 1 - Line 2	$ 13,560.00
4.	Projected Interstate Access Minutes Exhibit RCS-4, Line 1	707,012.00
5.	Traffic Sensitive Cost Per Minute of Use - Line 3 / Line 4	$ 0.01918

Therefore, the Commission does not find merit in the CMRS Providers' argument in this regard.

In addition, the Commission has found it difficult to effectively follow and analyze the methodology and proposed rate for Randolph outlined in witness Conwell's testimony. Witness Conwell has used several sources for input data in his proposed cost study, and the Commission has been unable to fully understand his proposed cost study.

Based upon the foregoing discussion and the evidence of record on this matter, the Commission finds that Randolph has proposed an alternative cost study that falls within the Guidelines outlined by the Commission in its *Modification Order*. However, the Commission does agree with the Public Staff that updated NECA average schedule formulae for the one-year period beginning on July 1, 2007 should be used and that the most current LSS formulae should also be used in Randolph's alternative cost study.

CONCLUSIONS

The Commission concludes that Randolph's alternative cost study used appropriate cost data and should be adopted. However, Randolph should update its alternative cost study to reflect the NECA average schedule formulae adopted for the one-year period beginning on July 1, 2007 and the most current LSS formulas.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

ISSUE NO. 13 – MATRIX ISSUE NO. 23: Did Randolph's study use embedded costs, and if so, was that appropriate?

POSITIONS OF PARTIES

RLECs: The RLECs asserted that Randolph's position on this issue is that its use of NECA average schedule data, which are based to some extent on embedded costs, in performing its alternative cost study was consistent with the Commission's alternative cost study Guidelines because Randolph used forward looking data to the extent feasible and practicable.

CMRS PROVIDERS: The CMRS Providers argued that Randolph's use of data from NECA average schedule companies was inappropriate because the data are based on embedded (historical) costs rather than forward-looking costs.

PUBLIC STAFF: The Public Staff argued that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate.

DISCUSSION

The RLECs stated in their Proposed Order that Randolph's use of NECA average schedule data was appropriate, and is a reasonable surrogate for its costs. The RLECs maintained that the NECA data are collected from ILECs all over the country and used in calculating an average schedule company's costs, which is appropriate for Randolph as it is an average schedule company.

The RLECs stated in their Post-Hearing Brief that the Commission should reject CMRS Providers witness Conwell's criticism of Randolph's use of the NECA cost data as impermissibly containing embedded cost data. The RLECs asserted that the Commission's alternative cost study Guidelines do not preclude the use of any embedded cost data. Rather, the RLECs maintained, Guideline No. 2 provides that cost data may be a surrogate for the company's costs, but should be forward looking and should reflect an efficient network to the extent practicable. The RLECs stated that, while the Public Staff recommended use of forward looking data to the extent practicable or feasible, the Guidelines did not impose an absolute requirement that such data be used. The RLECs noted that the Commission has ruled that an RLEC should use such data to the extent practicable.

The RLECs asserted that, if there are aspects of Randolph's study that the Commission deems to be reflective of embedded costs, it is fully consistent with the alternative cost study Guidelines to allow such costs. The RLECs stated that the use of some portion of such costs is also consistent with the Commission's overarching policy decision to suspend any obligation for the RLECs to perform TELRIC studies. The RLECs maintained that it was clearly the position of the Public Staff, as adopted by the Commission, that the RLECs, which petitioned for modification of any TELRIC requirements, should be afforded some latitude in being allowed to provide non-TELRIC alternative cost studies. Otherwise, the RLECs argued, the Commission's Section 251(f)(2) modification of any RLEC obligation to perform TELRIC studies is rendered meaningless.

The RLECs opined that Randolph's use of NECA cost study data, together with forward looking data to the extent they were readily available to Randolph, was reasonable and sufficient. The RLECs maintained that, to the extent Randolph used embedded cost data in its alternative cost study, the use of such data was not unreasonable or inconsistent with the Commission's Guidelines, as Randolph used forward looking data to the extent feasible and practicable. The RLECs argued that, accordingly, the Commission should reject the arguments offered by the CMRS Providers.

The RLECs argued that NECA's formulas are designed to develop a cost for the switching and transport of interstate traffic for average schedule ILECs. The RLECs noted that Randolph is an average schedule ILEC. The RLECs maintained that NECA's formulas are designed to estimate the cost of providing these functions for Randolph, based on its demand characteristics, network configuration, and number of circuits. The RLECs stated that the functions needed to terminate interstate access traffic are the same functions that are used to terminate wireless reciprocal compensation traffic.

On cross-examination during the evidentiary hearing witness Schoonmaker confirmed that the switching investment in Randolph's alternative cost study is based on embedded costs, but the investment does reflect forward-looking demand units.

In their Proposed Order, the CMRS Providers simply referenced their discussion of Matrix Issue No. 22 for Matrix Issue No. 23. No other discussion was provided.

The CMRS Providers asserted in their Post-Hearing Brief that the cost data used by Randolph clearly were not forward-looking. The CMRS Providers maintained that Randolph made no attempt whatsoever to use forward-looking data. Therefore, the CMRS Providers argued, the use of NECA average schedule company data was inappropriate pursuant to the Commission's *Modification Order.*

The CMRS Providers opined that the NECA average schedule company data are based upon embedded costs. The CMRS Providers noted that witness Schoonmaker confirmed this at the hearing and made no attempt to deny it. The CMRS Providers stated that for Randolph to claim that it used forward-looking data to the extent feasible and practicable is nothing more than a claim that the use of forward-looking data was not feasible or practicable. The CMRS Providers maintained that Randolph simply decided that the *Modification Order* relieved it from the duty to employ forward-looking costs in its study and thereafter proceeded to base its proposed rate on data and formulas used to compute interstate access charges. The CMRS Providers argued that Randolph used a method that Randolph's own consultant told Randolph, in a written document submitted prior to the commencement of the study, would include no forward-looking element to the cost.

The CMRS Providers argued that Randolph's cost study used embedded costs, which was inappropriate given the availability of the FCC's forward-looking switch cost data and current price quotations from switch vendors.

The Public Staff stated in its Proposed Order that the parties to this proceeding agree that Randolph's cost study used embedded cost data to some degree. The Public Staff maintained that the disagreement is over whether using these embedded costs was appropriate.

The Public Staff opined that the Commission's Guidelines specified that the cost data should be easily obtainable and verifiable and should reflect only the direct costs associated with the transport and termination of traffic. Furthermore, the Public Staff maintained, the Guidelines provided that the cost data may be a surrogate of the company's cost, but should be forward-looking and reflect an efficient network to the extent practicable. The Public Staff stated that the Commission's Guidelines never prohibit a company from using embedded costs.

The Public Staff recommended that the Commission conclude that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate.

The Commission notes that all of the parties agree that Randolph's alternative cost study is based, to some degree, on embedded costs, but Randolph noted that it reflects forward-looking demand units.

Guideline No. 2 of the Commission's *Modification Order* specified that, "the cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network to the extent practicable." The Commission determines that this Guideline does not prohibit the use of any embedded costs in alternative cost studies. The Commission notes that Randolph did reflect forward-looking demand units when using the NECA data reflecting the embedded costs of average schedule companies. In addition, as the Commission has found in Finding of Fact No. 11 above, the *Modification Order* does not require the RLECs to obtain a vendor switch quote. The Commission is persuaded by the record that obtaining a switch quote from a vendor is not practicable in this proceeding. The Commission determines, based on the *Modification Order*, that Randolph's use of NECA data which contains some degree of embedded costs is reasonable and appropriate.

CONCLUSIONS

The Commission concludes that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units. However, Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

ISSUE NO. 14 – MATRIX ISSUE NO. 23A: If not appropriate, what total switch investment per line should be used?

POSITIONS OF PARTIES

RLECs: The RLECs' position on Matrix Issue No. 23 is that, although Randolph's cost study was based to some extent on embedded costs, the study is appropriate and consistent with the Commission's alternative cost study Guidelines because Randolph used forward looking data to the extent feasible and practicable. Therefore, the RLECs' position on Matrix Issue No. 23A is that it is moot.

CMRS PROVIDERS: The CMRS Providers argued that Randolph's use of NECA average schedule company data was not appropriate. The CMRS Providers recommended that the Commission adopt a $168 switch investment per line for Randolph, along with the methodology recommended by CMRS Providers witness Conwell.

PUBLIC STAFF: The Public Staff argued that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate. The Public Staff further believes that, since Randolph's cost study inputs are appropriate, Matrix Issue Nos. 23A, 23B, 23C, and 23D are moot.

DISCUSSION

The RLECs noted in their Proposed Order that the CMRS Providers' position on this issue is that a switch investment of $168 per line should be used in Randolph's cost study. The RLECs maintained that this figure is based on FCC switch cost data, in 1999 dollars, from the *USF Inputs Order* for both rural and nonrural carriers, reduced by 12% based on the CMRS Providers' contention that there has been a decline in switch costs from 1999 to 2006.

The RLECs argued that Randolph's use of the NECA cost study data was appropriate, and is a reasonable surrogate for its costs. The RLECs noted that the NECA data are collected from ILECs all over the country and used in calculating an average schedule company's costs, which is appropriate for Randolph, as it is an average schedule company.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that, as in the case of MebTel, Randolph used embedded switch cost data to compute its proposed transport and termination rate. The CMRS Providers maintained that, however, unlike MebTel, Randolph has produced a study that does not appear to calculate a switch investment per line. The CMRS Providers noted that witness Conwell has taken the same FCC switch cost data he used in MebTel's proposed transport and termination rate and recommended that this value be used in a methodology incorporating standard cost principles for the development of transport and termination rates for Randolph. The CMRS Providers stated that, because Randolph's switch is smaller (4,700 lines) than the average of MebTel's three switches, Randolph's forward-looking switch investment per line is higher - $168 versus $143 per line.

The CMRS Providers argued that their evidence is the only evidence of Randolph's forward-looking switch costs in the record and should be adopted for Randolph and applied based on the methodology proposed by witness Conwell.

The CMRS Providers asserted in their Post-Hearing Brief that Randolph has presented no evidence of its forward-looking switch investment. The CMRS Providers maintained that, instead, Randolph relies exclusively on the NECA average schedule company data and formulae, which produce a number that cannot be analyzed. The CMRS Providers argued that, if the Commission rules that the use of such data and formula is inappropriate, then the only evidence of Randolph's forward-looking switching cost is the FCC data reduced to present value as presented by witness Conwell of $168 per line, which should be used in the transport and termination cost methodology also recommended by witness Conwell.

Since the Public Staff considered this issue moot based on its recommendation for Matrix Issue No. 23, it did not provide any discussion on this issue in its Proposed Order.

The Commission rules that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, however that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

ISSUE NO. 15 – MATRIX ISSUE NO. 23B: If not appropriate, what cable investment per foot should be used?

POSITIONS OF PARTIES

RLECs: The RLECs' position on Matrix Issue No. 23 is that, although Randolph's cost study was based to some extent on embedded costs, the study is appropriate and consistent with the Commission's alternative cost study Guidelines because Randolph used forward looking data to the extent feasible and practicable. Therefore, the RLECs' position on Matrix Issue No. 23B is that it is moot.

CMRS PROVIDERS: The CMRS Providers stated that CMRS Providers witness Conwell originally proposed a cable cost of $3.50 per foot. The CMRS Providers maintained that, because of concessions and changes made in Randolph witness Schoonmaker's rebuttal testimony, Randolph's cable cost should be modified to $2.90 per foot.

PUBLIC STAFF: The Public Staff argued that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate. The Public Staff further believes that, since Randolph's cost study inputs are appropriate, Matrix Issue Nos. 23A, 23B, 23C, and 23D are moot.

DISCUSSION

The RLECs noted in their Proposed Order that witness Conwell's proposed revision of Randolph's transport cable costs used $3.50 per foot for 24 fiber buried cable, assuming that only the interoffice transport system carrying mobile-to-land traffic used that cable. The RLECs asserted that, based on witness Schoonmaker's rebuttal testimony and Randolph's revised network diagram, the CMRS Providers contended that three adjustments are necessary. The RLECs noted that, first, the CMRS Providers believe the $3.50 per foot should be reduced to $2.90 per foot to reflect 12-fiber cable. The RLECs stated that the second adjustment proposed by the CMRS Providers would be an additional $1.77 per foot added to the $2.90 per foot for transport placement. The RLECs noted that the third adjustment recommended by the CMRS Providers would be that 62% of the total installed cost per foot of $4.67 should be attributed to the transport system carrying mobile-to-land traffic, and 32% to digital loop carriers (calculated as follows: 62% = 1 – (4.99 miles x 50%) / 6.61 miles). The RLECs stated that the CMRS Providers contended that the resulting cable investment should be $2.90 per foot.

The RLECs asserted that, in addressing this issue, witness Schoonmaker pointed out that the transport cable cost inputs represent the cost of the cable material and the cost of installing the fiber itself, but does not include any of the cost of the structures (using HAI terminology) that are needed to support the cable. The RLECs maintained that this input does not include pole costs if the cable is aerial, trenches and sheathing costs if the cable is buried, or trenches and conduits costs if the cable is underground. The RLECs stated that Randolph contended that this is an example of the problem with the approach witness Conwell has taken; witness Conwell selected an input out of the HAI 5.0a model but does not run the model, therefore, the remaining logic assumptions built into the model are excluded, resulting in an understatement of the cost that even the HAI model would produce. The RLECs argued that witness Conwell's use of the $3.50 input substantially understates Randolph's cost of building a cable with the necessary structures, i.e., trenching and sheathing for buried fiber. The RLECs noted that Randolph contended that this understatement of its cable cost is further exacerbated by witness Conwell's unwarranted and unreasonable proposed reduction of this cost to $2.90, when it is already understated at $3.50.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers stated in their Proposed Order that, as with switching costs, Randolph has employed the NECA average schedule formulae to compute its transport costs, and that Randolph's determination of those costs suffers the same problems as described for Matrix Issue No. 23A. The CMRS Providers asserted that, in addition, as with switching costs, the CMRS Providers were unable to determine from a review of Randolph's cost study what value, if any, Randolph proposed for cable cost per foot. The CMRS Providers maintained that the study appears to be silent on this point.

The CMRS Providers noted that witness Conwell originally proposed a cable cost of $3.50 per foot, which he used along with the 1.62 actual miles[1] to compute a proposed transport cost per minute (See Exhibit WCC-8 attached to witness Conwell's Direct Testimony). The CMRS Providers asserted that the value of $3.50 per foot is the default input value for 24 fiber cable in the publicly available HAI 5.0a cost model. The CMRS Providers stated that, although the cost data in the HAI model were developed by a private company, as opposed to the FCC switch cost data, the CMRS Providers are willing to accept it.

The CMRS Providers maintained that witness Schoonmaker's rebuttal testimony contained a revised network diagram (Exhibit RCS-5), which showed that not all of Randolph's cable contained 24 fibers. The CMRS Providers noted that, thus, witness Conwell's original estimate of $3.50 per foot should be reduced to $2.90 per foot to reflect the cost of 12-fiber cable. The CMRS Providers stated that this cost also comes from the publicly available HAI 5.0a model, section 4.4.13 of the Inputs Portfolio. The CMRS Providers maintained that, in addition, based upon appropriate criticism from witness Schoonmaker, $1.77 should be added to

[1] 1.62 miles represents the distance from Randolph's one switch to the meet-point with AT&T.

the $2.90 per foot for transport placement costs, bringing the total to $4.67 per foot. The CMRS Providers asserted that witness Schoonmaker's revised diagram indicated that only 62% of the total installed cost is attributable to the transport system, while the remainder is attributable to a DLC system which witness Schoonmaker conceded is not part of the transport system. The CMRS Providers argued that 62% of $4.67 is $2.90, which should be the value used for Randolph's cable cost per foot. The CMRS Providers recommended that the Commission adopt this value based on the methodology provided by witness Conwell.

The CMRS Providers asserted in their Post-Hearing Brief that Randolph has presented no evidence of its forward-looking cable cost per foot. The CMRS Providers maintained that, instead, Randolph relied exclusively on the NECA average schedule data, which employ embedded costs and also are not representative of Randolph's transport network, in a methodology that does not appear to even propose cable costs per foot. The CMRS Providers argued that, if the Commission rules that Randolph's study is inappropriate, then the only evidence of Randolph's forward-looking cable costs per foot comes from witness Conwell ($2.90 per foot).

Since the Public Staff considered this issue moot based on its recommendation for Matrix Issue No. 23, it did not provide any discussion on this issue in its Proposed Order.

The Commission notes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

ISSUE NO. 16 – MATRIX ISSUE NO. 23C: If not appropriate, what should be the total transport termination investment at Randolph's Liberty switch?

POSITIONS OF PARTIES

RLECs: The RLECs' position on Matrix Issue No. 23 is that, although Randolph's cost study was based to some extent on embedded costs, the study is appropriate and consistent with the Commission's alternative cost study Guidelines because Randolph used forward looking data to the extent feasible and practicable. Therefore, the RLECs' position on Matrix Issue No. 23C is that it is moot.

CMRS PROVIDERS: The CMRS Providers argued that the Commission should adopt a forward-looking transport termination investment for Randolph of $96,138 as reflected in witness Conwell's testimony.

PUBLIC STAFF: The Public Staff argued that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate. The Public Staff further believes that, since Randolph's cost study inputs are appropriate, Matrix Issue Nos. 23A, 23B, 23C, and 23D are moot.

DISCUSSION

The RLECs stated in their Proposed Order that the CMRS Providers argued that total transport termination investment per OC3 transport system at the Liberty switch of $88,200 should be used.

The RLECs asserted that forward-looking costs for transport are normally calculated assuming that redundant facilities and ring architecture are used to make network connections to improve network reliability. The RLECs maintained that the HAI 5.0a model from which witness Conwell takes some of his proposed inputs specifically uses this architecture. However, the RLECs argued that, here, witness Conwell does not apply that logic from the model, as his cost analysis assumes only a single network connection and a network configuration that does not reflect a forward-looking network design. The RLECs maintained that this understates Randolph's legitimate costs of transport elements.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that the NECA average schedule formulas employed in the Randolph cost study used embedded data that overstate the current cost to purchase transmission equipment. The CMRS Providers maintained that, moreover, the CMRS Providers cannot determine that Randolph's cost study even proposes a value for transmission equipment investment.

The CMRS Providers stated that Randolph indicated in response to a CMRS Providers data request that its transport network from the Liberty switch to the meet point with AT&T – the only portion of the transmission system involved with the transport of wireless traffic – uses an OC3 system. The CMRS Providers noted that witness Conwell has proposed an investment value for this system of $88,200, based on OC3 transmission equipment cost data from the publicly available HAI 5.0a model, plus an additional 9% loading for power plant, for a total of $96,138.

The CMRS Providers asserted in their Post-Hearing Brief that Randolph has presented no evidence of its forward-looking transmission equipment cost. The CMRS Providers maintained that, indeed, the CMRS Providers cannot even determine if Randolph has proposed a value for transmission equipment investment. The CMRS Providers argued that the only evidence of

Randolph's forward-looking transmission equipment costs comes from witness Conwell who recommended a forward-looking transport termination investment for Randolph of $96,138.

Since the Public Staff considered this issue moot based on its recommendation for Matrix Issue No. 23, it did not provide any discussion on this issue in its Proposed Order.

The Commission notes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

ISSUE NO. 17 – MATRIX ISSUE NO. 23D: If not appropriate, what effective annual cost factors should be used for switching, cable, and transmission equipment?

POSITIONS OF PARTIES

RLECs: The RLECs' position on Matrix Issue No. 23 is that, although Randolph's cost study was based to some extent on embedded costs, the study is appropriate and consistent with the Commission's alternative cost study Guidelines because Randolph used forward looking data to the extent feasible and practicable. Therefore, the RLECs' position on Matrix Issue No. 23D is that it is moot.

CMRS PROVIDERS: The CMRS Providers asserted that, absent company-specific data for Randolph, which has not been placed in the record, the Commission should adopt the corrected MebTel annual cost factors for switching (30.6%[1]), cable (23.9%), and transmission equipment (28.6%).

PUBLIC STAFF: The Public Staff argued that the cost study performed by Randolph is based, in part, upon the embedded costs of average schedule and cost companies, but the use of these costs is appropriate. The Public Staff further believes that, since Randolph's cost study inputs are appropriate, Matrix Issue Nos. 23A, 23B, 23C, and 23D are moot.

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[1] As noted in the discussion of Finding of Fact No. 9 herein, MebTel's actual proposed annual cost factor is 30.5%

DISCUSSION

The RLECs stated in their Proposed Order that the CMRS Providers contended that, absent company-specific cost data for Randolph, the revised switching, cable, and transmission equipment annual cost factors which the CMRS Providers proposed for MebTel should also be used for Randolph.

The RLECs asserted that, while witness Conwell finds it convenient to propose the application to Randolph of the annual cost factors that he proposed for MebTel, there is no evidence establishing that it is appropriate to apply those factors to Randolph. The RLECs maintained that Randolph is a significantly smaller company than MebTel and that the assumptions that various factors developed from MebTel's records are appropriate for Randolph has not been shown to be correct. The RLECs noted that smaller companies frequently have a higher ratio of common costs to direct costs than larger companies. The RLECs asserted that ratios of maintenance expenses to investment amounts may vary between companies based on the geography of the area served, the density of customers, and the age and type of equipment being used. The RLECs argued that, while the depreciation rates for both companies presumably fall within ranges established by the FCC, they may differ between the companies with a resulting difference in the appropriate carrying charge.

The RLECs also noted that witness Conwell's own testimony shows that there are additional differences between MebTel and Randolph, making it inappropriate to apply witness Conwell's assumptions and proposals for MebTel to Randolph. Specifically, the RLECs argued, witness Conwell raised issues with MebTel's carrying charges, its cost of money calculation, and its planned adjustment to deferred income taxes.

The RLECs did not offer any additional, substantive discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that the issue here is the same as with other Randolph switching and transport issues. The CMRS Providers maintained that Randolph's cost study does not appear to use, or even to propose, annual cost factors for switching, cable, or transport equipment. The CMRS Providers asserted that, yet, a proper transport and termination rate for Randolph cannot be computed without such factors. The CMRS Providers argued that, in the absence of company-specific data, which Randolph has not provided, the CMRS Providers propose that the same annual cost factors be used for Randolph as for MebTel.

The CMRS Providers stated that they have agreed to accept MebTel's modified annual cost factor for switching of 30.6%.[1] The CMRS Providers noted that the same should be used to compute Randolph's switching costs. The CMRS Providers maintained that witness Conwell has proposed a MebTel annual cost factor for cable of 23.9%, based on the 10.1% cost of capital

[1] As noted in the discussion of Finding of Fact No. 9 herein, the CMRS Providers stated that MebTel's proposed annual cost factor is 30.6%. However, MebTel's actual proposed annual cost factor is 30.5%. The Commission is assuming that the CMRS Providers are in agreement with the 30.5% annual cost factor proposed by MebTel.

required by the Commission's *Modification Order*, and excluding customer operations expenses. The CMRS Providers argued that the same should be used for Randolph. The CMRS Providers stated that, likewise, witness Conwell has proposed for MebTel a corrected annual cost factor for transmission equipment of 28.6%. The CMRS Providers opined that, again, the factor should be used for Randolph.

The CMRS Providers asserted in their Post-Hearing Brief that, as in Matrix Issue Nos. 23A through 23C above, Randolph has presented no evidence to support annual cost factors for switching, cable, and transmission equipment. The CMRS Providers maintained that it is unclear if Randolph's cost study even makes use of such factors. The CMRS Providers stated that the only evidence of appropriate annual cost factors comes from witness Conwell, and the Commission should adopt his recommendations, as follows: 30.6% for switching, 23.9% for cable, and 28.6% for transmission equipment.

Since the Public Staff considered this issue moot based on its recommendation for Matrix Issue No. 23, it did not provide any discussion on this issue in its Proposed Order.

The Commission notes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 12 that Randolph's alternative cost study does use embedded costs to some degree with forward-looking demand units, but that Randolph's use of these embedded costs is reasonable and appropriate and in compliance with the Commission's *Modification Order*, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

ISSUE NO. 18 – MATRIX ISSUE NO. 24: Did Randolph's study assume that 70% of Randolph's switching costs were usage-sensitive, and if so, was that appropriate?

ISSUE NO. 19 – MATRIX ISSUE NO. 24A: If not appropriate, what percentage of total switching annual costs should be recovered by Randolph's transport and termination rate?

POSITIONS OF PARTIES

RLECs: The RLECs maintained that Randolph's position is that its cost study appropriately included 70% of its switching investment as that percentage was both reasonable and consistent with prior FCC Orders and the Commission's rulings involving UNE pricing for AT&T and other large ILECs. The RLECs argued that the inclusion of 70% of Randolph's switching investment in development of its rate is reasonable.

TELECOMMUNICATIONS – MISCELLANEOUS

CMRS PROVIDERS: The CMRS Providers maintained that, in theory, Randolph's cost study assumed that 70% of Randolph's switching investment and costs were usage-sensitive. The CMRS Providers asserted that, based upon the evidence presented by MebTel, and upon previous decisions of the Commission, however, that 70 percent is too high. The CMRS Providers argued that the appropriate percentage of usage-sensitive switching investment and costs for Randolph is 38%. This is the same figure the CMRS Providers recommended for MebTel.

PUBLIC STAFF: The Public Staff maintained that Randolph's cost study assumed that 70% of the switching costs are traffic sensitive and that it is neither unreasonable nor inappropriate to use this factor.

DISCUSSION

The RLECs stated in their Proposed Order that the CMRS Providers' position on this issue is that Randolph, by using NECA average schedule switching data, impermissibly assumed that 70% of its switching costs were usage-sensitive. The RLECs stated that the CMRS Providers contended that this was not appropriate because very little, if any, of the costs of a modern, digital switch are usage-sensitive.

The RLECs maintained that the CMRS Providers argued that only 10.9% of Randolph's total annual switching costs should be recovered in its transport and termination rate, which is the ratio of the CMRS Providers' proposed $18.33 per line investment for interoffice trunk equipment and the CMRS Providers' proposed forward-looking total switch investment cost for Randolph of $168 per line.

The RLECs asserted that Randolph's position is that its cost study appropriately included 70% of its switching investment, and the 70% figure was both reasonable and consistent with prior FCC Orders and the Commission's rulings involving UNE pricing for AT&T and other large ILECs. The RLECs recommended that the Commission find that the inclusion of 70% of Randolph's switching investment in the development of its rate was reasonable.

The RLECs did not provide any additional discussion of this issue in their Post-Hearing Brief.

The CMRS Providers stated in their Proposed Order that Randolph admitted on the Joint Issues Matrix filed in this proceeding that its cost study assumes that 70% of switching investment and costs are usage sensitive. The CMRS Providers noted that Randolph witness Schoonmaker likewise admitted this fact during cross-examination. The CMRS Providers asserted that, however, they have been unable to determine, from an examination of Randolph's cost study, exactly how this percentage has been applied. The CMRS Providers stated that they assume that the NECA average schedule data include only 70% of total embedded switching investment and costs, but this fact is not made clear in witness Schoonmaker's testimony.

The CMRS Providers maintained that there is no clear way to make a change to this percentage in Randolph's current cost study, because there is no line entry for the usage-sensitive percentage of total switching investment and costs. The CMRS Providers asserted that, thus, in determining the appropriate transport and termination rate for Randolph, the Commission must apply the appropriate usage-sensitive percentage in the methodology used by CMRS Providers witness Conwell.

The CMRS Providers argued that the usage-sensitive portion of a switch is the trunking equipment and switch matrix. The CMRS Providers maintained that, in the case of MebTel, continuing property records were provided demonstrating that 38% of MebTel's total switch investment is usage-sensitive. The CMRS Providers opined that, in the absence of Randolph-specific data, the CMRS Providers request that the Commission adopt a usage-sensitive percentage for Randolph consistent with the percentage shown by MebTel's records – 38%. The CMRS Providers recommended that the Commission adopt the 38% figure for Randolph.

The CMRS Providers stated that, in the alternative, if Randolph will complete an analysis of its continuing property records to categorize switching plant according to the categories in the MebTel property records, Randolph may develop a company-specific usage-sensitive percentage.

The CMRS Providers specified in their Post-Hearing Brief that the CMRS Providers attempted the same analysis for Randolph as they did for MebTel and that Randolph had provided a copy of its continuing property records in response to a CMRS Providers data request. The CMRS Providers argued that, however, Randolph's records do not map line item investments to switch categories – line side ports, trunk side ports, etc. . . – as did MebTel's continuing property records. The CMRS Providers noted that Exhibit WCC-6 to witness Conwell's direct testimony allows this mapping to be done, and some line items have been mapped to categories. The CMRS Providers asserted that, if Randolph will complete the mapping, a company-specific usage-sensitive portion of switch investment can be computed, and the CMRS Providers would not object if Randolph would provide this information for use in developing an appropriate transport and termination rate.

The CMRS Providers stated that, currently, however, they lack the data to complete the mapping. Therefore, the CMRS Providers maintained that, in the absence of Randolph-specific data, the CMRS Providers request that the Commission adopt a usage-sensitive percentage for Randolph consistent with the percentage shown by MebTel's records – 38%.

The CMRS Providers asserted that the 70% figure employed in the NECA average schedule data and formulas are based upon the FCC's Part 69 access charge rules. The CMRS Providers noted that other FCC rules specifically prohibit Randolph from applying access charges for the transport and termination of wireless traffic, specifically §51.515(a). Consequently, the CMRS Providers argued, the Commission should not adopt 70% as the percentage of usage-sensitive switching costs to be applied to the computation of Randolph's transport and termination rate, absent any company-specific information to support such a figure. The CMRS Providers recommended that the Commission adopt 38% as the usage-sensitive switching factor to be used in determining Randolph's transport and termination rate.

The Public Staff asserted in its Proposed Order that the parties agree that Randolph's cost study reflects the assumption that 70% of switching costs are traffic sensitive; the disagreement centers on whether this is appropriate.

The Public Staff noted that witness Conwell argued that little or no part of the switch is considered to be traffic sensitive. The Public Staff asserted that witness Conwell's testimony regarding MebTel's Mebane DCO switch is that only 15% of the switch should be considered to be traffic sensitive. The Public Staff stated that witness Conwell added that some states have even taken the position that a switch has no traffic sensitive costs.

The Public Staff maintained that, as it discussed in Matrix Issue Nos. 20 and 21, there is a wide variance regarding what portion of a switch should be considered to be traffic sensitive. The Public Staff noted that, indeed, both the FCC and the California Public Utilities Commission have adopted a 70% traffic sensitive factor for switching investment. The Public Staff also asserted that it has recommended in this proceeding that the Commission conclude that the use of a 70% traffic sensitive factor is appropriate for MebTel's Milton and Gatewood switches. The Public Staff argued that, likewise, Randolph's cost study assumption that 70% of the switching costs are traffic sensitive is neither unreasonable nor inappropriate.

The Commission notes that the Parties appear to agree that Randolph's alternative cost study assumes that 70% of Randolph's switching costs are usage-sensitive. The evidence reflects that the NECA average schedule switching data that were used by Randolph in its alternative cost study assumes that 70% of switching costs are usage-sensitive. The Commission further notes that it has found in Finding of Fact No. 10 above that MebTel should reflect 38% of its switching costs as usage-sensitive in its alternative cost study. As noted by the Commission in Finding of Fact No. 10, it is generally better practice to use company-specific information when such information is readily available. The CMRS Providers asserted that they have received Randolph's continuing property records in response to a data request in this proceeding; however, they have not been able to map the accounts correctly to determine the appropriate usage sensitive switching costs. The Commission determines that it is appropriate to request Randolph and the CMRS Providers to review the continuing property records together to attempt to agree on the appropriate Randolph-specific usage sensitive switching costs to be included in Randolph's alternative cost study. With the needed information readily available, the Commission determines that this issue can be settled after brief discussions between the parties to come to agreement on the usage sensitive switching costs for Randolph.

CONCLUSIONS

The Commission concludes that it is appropriate to request Randolph and the CMRS Providers to review Randolph's continuing property records together to attempt to agree on the appropriate Randolph-specific usage sensitive switching costs to be included in Randolph's alternative cost study. Since the Commission has concluded in Finding of Fact No. 23 herein that it was appropriate for Ellerbe to adopt Randolph's alternative cost study, Ellerbe should adopt the usage sensitive switching costs agreed to by the Parties for Randolph as a surrogate for Ellerbe's usage sensitive switching costs.

TELECOMMUNICATIONS – MISCELLANEOUS

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

ISSUE NO. 20 – MATRIX ISSUE NO. 25: Did Randolph's study reflect existing utilization levels rather than forward-looking utilization, and, if so, was that appropriate?

POSITIONS OF PARTIES

RLECs: Randolph's alternative cost study reflects forward-looking utilization to the extent it was practicable and feasible, and its cost study is consistent with the Commission's alternative cost study Guidelines.

CMRS PROVIDERS: By using NECA average schedule cost data, the Randolph study reflects the existing utilization levels of the RLECs represented in the data. Consequently, there is no way to determine if the data reflect the "most efficient network" configuration or not. This is especially true since Randolph's study does not list or describe any of the utilization levels used. Therefore, Randolph's transport and termination rate should be computed based upon the utilization levels proposed by CMRS Providers witness Conwell, using the methodology described in his testimony.

PUBLIC STAFF: Randolph's study reflects forward-looking utilization and is consistent with the Commission's Guidelines established in Docket No. P-100, Sub 159. As such, the study has met the forward-looking requirements to the extent practicable.

DISCUSSION

The RLECs stated in their Proposed Order that Randolph's alternative cost study reflected forward-looking utilization to an extent that was practicable and feasible and that its cost study is consistent with the Commission's alternative cost study Guidelines.

The RLECs asserted that the adjustments proposed by witness Conwell are not necessary or appropriate. The RLECs maintained that witness Conwell's proposed adjustments are based on effectively ignoring the Commission's alternative cost study Guidelines and attempting to apply TELRIC regulations to this proceeding.

The RLECs maintained that Randolph's alternative cost study is based on NECA's traffic-sensitive formulas contained in Exhibit RCS-1 attached to witness Schoonmaker's testimony, relating to transport and termination costs. The RLECs noted that projected demand units are used as inputs into modified traffic-sensitive formulas to derive per-minute rates for transport and termination. The RLECs stated that, similar to NECA's average schedule formulas, company-specific inputs are used to determine switching, transport, and SS7 costs. The RLECs asserted that these costs are then converted to a per-minute rate for the provisions of these services.

The RLECs noted that Randolph's study was based on the latest available 24 months of actual data from Randolph for minutes of use and access lines, both of which were used to calculate a rolling 12-month average for use as a base point. The RLECs stated that to reflect projected minutes and access lines into the future, this base point was adjusted to project average monthly MOU and access lines based on the premise that they will increase/decrease in the next year at the same rates as they did in the past year.

The RLECs argued that NECA's formulas are designed to develop a cost for the switching and transport of interstate traffic for average schedule ILECs. The RLECs noted that Randolph is an average schedule ILEC. The RLECs maintained that NECA's formulas are designed to estimate the cost of providing these functions for Randolph, based on its demand characteristics, network configuration, and number of circuits. The RLECs stated that the functions needed to terminate interstate access traffic are the same functions that are used to terminate wireless reciprocal compensation traffic.

The RLECs recommended that the Commission conclude that Randolph's cost study complies with the Commission's alternative cost study Guidelines and that the costs developed by that cost study are reasonable surrogates for Randolph's costs for transport and termination. The RLECs proposed that the Commission conclude that Randolph's study appropriately reflected forward-looking utilization levels, to the extent practicable.

The RLECs did not provide any additional discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that the *Modification Order* requires Randolph's cost study to reflect an efficient network to the extent practicable. The CMRS Providers maintained that this is consistent with the FCC's requirements outlined in Paragraph 685 of the FCC's *First Report and Order*, as follows:

> We, therefore, conclude that the forward-looking pricing methodology for interconnection and unbundled network elements should be based on costs that assume that wire centers will be placed at the incumbent LEC's current wire center locations, but that the reconstructed local network will employ the most efficient technology for reasonably foreseeable capacity requirements.

The CMRS Providers asserted that it is impossible to determine if the input values used represent efficient usage, or even what values the study uses, or even if the study uses any values at all. The CMRS Providers recommended specific values in Matrix Issue Nos. 25A through 25D. The CMRS Providers recommended that the Commission conclude that Randolph's study used existing utilization levels rather than forward-looking utilization and that this is not appropriate.

The CMRS Providers did not provide any additional discussion on this issue in their Post-Hearing Brief.

The Public Staff stated in its Proposed Order that the Commission's alternative cost study Guidelines established in Docket No. P-100, Sub 159 allow the RLECs to conduct a study that is forward-looking and reflects an efficient network to the extent practicable.

The Public Staff opined that a reasonable interpretation of the Commission's Guidelines is that the demand used in the price-out of Randolph's cost study should be forward-looking to the extent practicable. Furthermore, the Public Staff maintained, the network should reflect an efficient design. The Public Staff asserted that a review of witness Conwell's testimony indicates that his objections to Randolph's cost study resulted from its failure to use an appropriate number for the minutes of use per line. The Public Staff noted that witness Conwell offered that the Commission should instead reject the minutes of use in Randolph's cost study and substitute the minutes per line contained in MebTel's study.

The Public Staff recommended that the Commission not accept that the wholesale substitution of inputs obtained from a company with three times the number of access lines as Randolph will render its study more efficient or forward-looking than the one produced using Randolph-specific inputs. The Public Staff opined that the effect of witness Conwell's mass substitutions and assumptions will fail to reflect adequately the manner in which Randolph will be providing service.

The Public Staff maintained that witness Conwell appears to believe that he must adjust the cost study performed by Randolph to make it TELRIC-compliant. The Public Staff asserted that TELRIC-compliant rates are not required under the Guidelines adopted by the Commission. The Public Staff argued that, instead, the rates should, to the extent practicable, reflect the costs and manner in which Randolph is providing service.

The Public Staff recommended that the Commission conclude that Randolph's cost study complies with the Commission's Guidelines set forth in Docket No. P-100, Sub 159 and, as such, the study meets the forward-looking requirement to the extent practicable.

The Commission notes that Guideline No. 2 in the Commission's *Modification Order*, which is in contention in this issue, states, "The cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network to the extent practicable."

The CMRS Providers asserted that Randolph's alternative cost study reflects the existing utilization levels of the RLECs represented in the NECA average schedule cost data. The CMRS Providers do not believe that it is possible to determine if this data reflects the most efficient network configuration for Randolph or not. Randolph stated that its study was based on the latest available 24 months of actual data from Randolph for minutes of use and access lines, which were then used to calculate a rolling 12-month average for use as a base point. Randolph specified that, to reflect projected minutes and access lines into the future, Randolph adjusted the base point to project average monthly MOU and access lines based on the premise that they will increase/decrease in the next year at the same rates as they did in the past year.

The Commission agrees with the Public Staff that TELRIC-compliant rates are not required under the Guidelines adopted in the *Modification Order*. Specifically, the Commission notes that the *Modification Order* states that TELRIC cost studies would be unduly economically burdensome to the RLECs and that granting relief from producing TELRIC cost studies is consistent with the public convenience and necessity.

It appears that Randolph has used its actual data for minutes of use and access lines and projected those into the future based on the increases or decreases experienced during the past year. As noted by the Commission in Findings of Fact Nos. 10 and 17 hereinabove, it is generally better practice to use company-specific information when such information is readily available. The Commission determines that Randolph's methodology does comply with the Commission's Guidelines and that Randolph's utilization levels are forward-looking to the extent practicable.

CONCLUSIONS

The Commission concludes that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

ISSUE NO. 21 – MATRIX ISSUE NO. 25A: If not appropriate, what annual switched minutes per line should be used for Randolph to compute switching costs per minute?

POSITIONS OF PARTIES

RLECs: The RLECs believe that Randolph's alternative cost study reflects forward-looking utilization to an extent that was practicable and feasible and that its cost study is consistent with the Commission's alternative cost study Guidelines. The RLECs contended that Randolph's use of 24 months of its actual traffic history is an accurate basis for projecting future demand. The RLECs also do not believe that there has been an adequate showing that data relating to MebTel, which is nearly four times the size of Randolph, is appropriately applied to Randolph. The RLECs further believe that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

CMRS PROVIDERS: By using NECA average schedule cost data, Randolph's study reflected the existing utilization levels of the RLECs represented in the data. Consequently, there is no way to determine if the data reflect the "most efficient network" configuration or not. This is especially true since Randolph's study does not list or describe any of the utilization levels used. Therefore, Randolph's transport and termination rate should be computed based upon the utilization levels proposed by witness Conwell, using the methodology described in his testimony. Witness Conwell proposed that Randolph's transport and termination rates be computed based upon MebTel's switched minutes per line per year of 15,372.

PUBLIC STAFF: The Public Staff believes that Randolph's study reflects forward-looking utilization and is consistent with the Commission's Guidelines established in Docket No. P-100, Sub 159. As such, the Public Staff believes that the study has met the forward-looking requirements to the extent practicable and is appropriate. The Public Staff further believes that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

TELECOMMUNICATIONS – MISCELLANEOUS

DISCUSSION

The RLECs asserted in their Proposed Order that, since they recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot. The RLECs did not provide any further discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that Randolph's cost study does not give an input value for minutes of use per line; therefore, it is impossible to determine whether the Randolph study assumes an efficient utilization of the Randolph network. The CMRS Providers maintained that, for this reason, they propose that the Commission conclude that Randolph's transport and termination rates should be computed based upon MebTel's switched minutes per line per year.

The CMRS Providers maintained in their Post-Hearing Brief that MebTel's cost study used a value of 15,372 switched minutes per line. The CMRS Providers asserted that this was consistent with the evidence produced by witness Conwell, who testified that in a report entitled "A Survey of Unbundled Network Element Prices in the United States – Updated March 2006", the Consumer Advocate Division of the Public Service Commission of West Virginia stated:

> Several parties have argued that the 1000 minutes of use (MOU) [per month] used in this survey for switching costs are too low to give an accurate measure of the cost of a basic UNE-P. It is pointed out that the national average monthly MOU is approximately 1400 MOU, and that several states have average MOU in excess of 2000 MOU per month.

The CMRS Providers asserted that Randolph's cost study does not give an input value for minutes of use per line; therefore, it is impossible to determine whether Randolph's study assumes an efficient utilization of Randolph's network. Therefore, the CMRS Providers recommended that the Commission compute Randolph's transport and termination rates based upon MebTel's switched minutes per line per year, or 15,327[1].

The Public Staff stated in its Proposed Order that, since it recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot.

The Commission notes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

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[1] The CMRS Providers reflected both 15,372 and 15,327 in their Post-Hearing Brief. The correct number is 15,372.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

ISSUE NO. 22 – MATRIX ISSUE NO. 25B: If not appropriate, what percentage of total interoffice cable costs should be attributed to transport carrying mobile-to-land traffic versus transport carrying Digital Loop Carriers (DLCs) and other uses?

POSITIONS OF PARTIES

RLECs: The RLECs believe that CMRS Providers witness Conwell's proposed adjustments are based on effectively ignoring the Commission's alternative cost study Guidelines and attempting to apply TELRIC regulations to this proceeding. The RLECs further believe that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

CMRS PROVIDERS: By using NECA average schedule cost data, Randolph's study reflected the existing utilization levels of the RLECs represented in the data. Consequently, there is no way to determine if the data reflect the "most efficient network" configuration or not. This is especially true since Randolph's study does not list or describe any of the utilization levels used. Therefore, Randolph's transport and termination rate should be computed based upon the utilization levels proposed by witness Conwell, using the methodology described in his testimony.

PUBLIC STAFF: The Public Staff believes that Randolph's study reflects forward-looking utilization and is consistent with the Commission's Guidelines established in Docket No. P-100, Sub 159. As such, the Public Staff believes that the study has met the forward-looking requirements to the extent practicable and is appropriate. The Public Staff further believes that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

DISCUSSION

The RLECs asserted in their Proposed Order that, since they recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot. The RLECs did not provide any further discussion on this issue in their Post-Hearing Brief.

The CMRS Providers asserted in their Proposed Order that the questions raised in this issue are discussed in Matrix Issue No. 23B (See the Evidence and Conclusions for Finding of Fact No. 14) in relation to the value to be used for Randolph's cable cost per foot. The CMRS Providers noted that, in that discussion, it was pointed out that the network diagram attached to witness Schoonmaker's rebuttal testimony demonstrates that 38% of Randolph's interoffice cable is dedicated to DLC systems not involved in the transport and termination of wireless traffic. The CMRS Providers maintained that the FCC's efficient network requirement means that 38% of Randolph's total cable costs must therefore be excluded from Randolph's transport and termination rate. The CMRS Providers asserted that, since Randolph's study does not present an input value for cable cost per foot, or any other cable value, this percentage of cable used for DLC systems must be subtracted from the cable cost value used in the methodology presented by witness Conwell.

The CMRS Providers recommended in their Post-Hearing Brief that the Commission find that 62% of interoffice cable attributed to transport should be included in Randolph's alternative cost study.

The Public Staff stated in its Proposed Order that, since it recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot.

The Commission notes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

ISSUE NO. 23 – MATRIX ISSUE NO. 25C: If not appropriate, what should be the total demand (in DS0 equivalents) for computing Randolph's transport system cable annual costs per trunk?

POSITIONS OF PARTIES

RLECs: The RLECs asserted that CMRS Providers witness Conwell's proposed adjustments are based on effectively ignoring the Commission's alternative cost study Guidelines and attempting to apply TELRIC regulations to this proceeding. The RLECs further believe that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

CMRS PROVIDERS: By using NECA average schedule cost data, Randolph's study reflected the existing utilization levels of the RLECs represented in the data. Consequently, there is no way to determine if the data reflect the "most efficient network" configuration or not. This is especially true since Randolph's study does not list or describe any of the utilization levels used. Therefore, Randolph's transport and termination rate should be computed based upon the utilization levels proposed by witness Conwell, using the methodology described in his testimony.

PUBLIC STAFF: The Public Staff believes that Randolph's study reflects forward-looking utilization and is consistent with the Commission's Guidelines established in Docket No. P-100, Sub 159. As such, the Public Staff believes that the study has met the forward-looking requirements to the extent practicable and is appropriate. The Public Staff further believes that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

DISCUSSION

The RLECs asserted in their Proposed Order that, since they recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot. The RLECs did not provide any further discussion on this issue in their Post-Hearing Brief.

The CMRS Providers maintained in their Proposed Order that, in computing transport costs for cable and transmission equipment, the total demand on the transport system must be figured. The CMRS Providers stated that this is usually done in voice-circuit (DS0) equivalents. The CMRS Providers noted that, as with all other transport costs, it is impossible to determine how Randolph's study calculated total demand, or how such a figure, if computed at all, was applied in determining the proposed rate. The CMRS Providers asserted that, yet, this is a crucial issue. The CMRS Providers argued that, if a cost study assumes low total demand, i.e., assumes that the transport network is not being efficiently utilized, then transport costs per minute will be unreasonably inflated.

The CMRS Providers noted that Randolph's responses to data request indicated that the company operates an OC3 transport system. The CMRS Providers stated that witness Conwell's testimony for Randolph therefore assumed only a 33% utilization level for transport – 672 DS0 equivalents. The CMRS Providers maintained that witness Conwell pointed out that this is likely a conservative (low) estimate of total demand, because Randolph indicated in responses to data requests that it has 431 interoffice trunks between the Liberty Switch and the meet-point with AT&T. The CMRS Providers asserted that this leaves 241 DS0 equivalents or approximately 10 DS1s for special access and other dedicated circuits. The CMRS Providers recommended that the Commission adopt witness Conwell's suggestion of a 33% utilization level for transport.

The CMRS Providers specified in their Post-Hearing Brief that a total demand of 672 in DS0 equivalents should be included in Randolph's cost study.

The Public Staff stated in its Proposed Order that, since it recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot.

The Commission notes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

ISSUE NO. 24 – MATRIX ISSUE NO. 25D: If not appropriate, what should be the total demand (in DS0 equivalents) for computing transport termination annual costs per trunk?

POSITIONS OF PARTIES

RLECs: The RLECs maintained that CMRS Providers witness Conwell's proposed adjustments are based on effectively ignoring the Commission's alternative cost study Guidelines and attempting to apply TELRIC regulations to this proceeding. The RLECs further believe that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

CMRS PROVIDERS: By using NECA average schedule cost data, Randolph's study reflected the existing utilization levels of the RLECs represented in the data. Consequently, there is no way to determine if the data reflect the "most efficient network" configuration or not. This is especially true since Randolph's study does not list or describe any of the utilization levels used. Therefore, Randolph's transport and termination rate should be computed based upon the utilization levels proposed by witness Conwell, using the methodology described in his testimony.

PUBLIC STAFF: The Public Staff believes that Randolph's study reflects forward-looking utilization and is consistent with the Commission's Guidelines established in Docket No. P-100, Sub 159. As such, the Public Staff believes that the study has met the forward-looking requirements to the extent practicable and is appropriate. The Public Staff further believes that, since the utilization levels used in Randolph's cost study are appropriate, Matrix Issue Nos. 25A, 25B, 25C, and 25D are moot.

DISCUSSION

The RLECs asserted in their Proposed Order that, since they recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot. The RLECs did not provide any further discussion on this issue in their Post-Hearing Brief.

The CMRS Providers maintained in their Proposed Order that, in computing transport costs for both cable and transmission equipment, the total demand on the transport system must be determined. The CMRS Providers stated that this is usually done in voice-circuit (DS0) equivalents. The CMRS Providers noted that, as with all other transport costs, it is impossible to determine how Randolph's study calculated total demand, or how such a figure, if computed at all, was applied in determining the proposed rate. The CMRS Providers asserted that, yet, this is a crucial issue. The CMRS Providers argued that, if a cost study assumes low total demand, i.e., assumes that the transport network is not being efficiently utilized, then transport costs per minute will be unreasonably inflated.

The CMRS Providers noted that Randolph's responses to data request indicated that the company operates an OC3 transport system. The CMRS Providers stated that witness Conwell's testimony for Randolph therefore assumed only a 33% utilization level for transport – 672 DS0 equivalents. The CMRS Providers maintained that witness Conwell pointed out that this is likely a conservative (low) estimate of total demand, because Randolph indicated in response to data requests that it has 431 interoffice trunks between the Liberty Switch and the meet-point with AT&T. The CMRS Providers asserted that this leaves 241 DS0 equivalents or approximately 10 DS1s for special access and other dedicated circuits. The CMRS Providers recommended that the Commission adopt witness Conwell's suggestion of a 33% utilization level for transport.

The CMRS Providers specified in their Post-Hearing Brief that a total demand of 672 in DS0 equivalents should be included in Randolph's cost study.

The Public Staff stated in its Proposed Order that, since it recommended for Matrix Issue No. 25 that the Commission find that Randolph's study reflected forward-looking utilization levels, to the extent practicable, Matrix Issue Nos. 25A through 25D are moot.

The Commission notes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

CONCLUSIONS

The Commission concludes that, since it has concluded in Finding of Fact No. 18 that Randolph's alternative cost study reflects forward-looking utilization to the extent practicable and is appropriate, this issue is moot.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

ISSUE NO. 25 - MATRIX ISSUE NO. 26: Was it appropriate for Ellerbe to adopt Randolph's cost study?

POSITIONS OF PARTIES

RLECs: The RLECs argued that Randolph's cost study evidence does provide a reasonable surrogate for Ellerbe's cost.

CMRS PROVIDERS: The CMRS Providers asserted that Randolph's cost study does not provide a reasonable surrogate for Ellerbe's cost because Ellerbe's switch size is smaller than the Randolph switch, and its interoffice transport cable distance is different; Ellerbe's specific costs were readily and easily attainable; and, witness Conwell's corrected cost for Ellerbe should be used to establish a transport and termination rate appropriate for Ellerbe.

PUBLIC STAFF: The Public Staff stated that Randolph's cost study is a reasonable and appropriate surrogate for Ellerbe's cost.

DISCUSSION

In Docket No. P-100, Sub 159, the Commission permitted RLECs to develop a modified cost study to determine the appropriate reciprocal compensation rate using (in addition to others) the following Guideline:

> 2. The cost data may be a surrogate of the company's cost, but should be forward-looking and reflect an efficient network to the extent practicable.

In compliance with the above, Ellerbe opted to adopt Randolph's cost study as a surrogate for its costs in determining the appropriate reciprocal compensation rates.

Ellerbe took this approach because it could not have performed its own TELRIC study due to the cost of such a study. Witness Long testified that Ellerbe has only 12 employees; none of whom have the knowledge or experience necessary to conduct such a study. Therefore, witness Long recommended that Ellerbe adopt Randolph's cost study as a surrogate. Witness Long acknowledged that Randolph is twice as big as Ellerbe, and therefore, Ellerbe's costs were likely greater than Randolph's. Nevertheless, witness Long believed it was more prudent to adopt the cost study of another RLEC that most closely approximates Ellerbe's size and circumstances than to bear the cost of engaging a third party consultant to perform the Ellerbe-specific cost study. [1]

Witness Conwell objected to Ellerbe's adopting Randolph's cost study because, in his view, Randolph's study inappropriately relied upon data derived from NECA average companies that utilized embedded (historical) data rather than strict forward looking cost data in developing its cost studies. The Commission has previously rejected this contention in our discussion about the merits of the Randolph study and has approved of the Randolph study as modified herein.

After carefully reviewing the evidence and the argument in this proceeding, the Commission reaffirms the findings that it reached in Docket P-100, Sub 159. That is, from the evidence here presented, it is indisputable that Ellerbe is a rural telecommunications company as defined by the Act and that, by virtue of its size, requiring it to determine its reciprocal compensation rates on the basis of data derived from company specific forward looking cost data would be unnecessary from a business and customer perspective and would be cost prohibitive. From the Commission's review of the evidence, it concludes that it would not have been simple

[1] In Docket P-100, Sub 159, we noted that the cost to Ellerbe of conducting a TELRIC study would approach or exceed the total reciprocal compensation that Ellerbe would receive from all CMRS providers in 2004.

or inexpensive for Ellerbe to have performed its own TELRIC study, or to have performed a TELRIC type study as suggested by CMRS Providers witness Conwell. Rather, from the evidence presented in this docket, the Commission finds merit in Ellerbe's basic contention that what appears simple and inexpensive for a large company, is not so simple and inexpensive for a small ILEC like Ellerbe with 12 employees and 2,219 subscribers.

In Docket No. P-100, Sub 159, the Commission concluded that the forced application of TELRIC principles to Ellerbe and the other petitioners would be likely to cause undue economic burden beyond the economic burden that is typically associated with efficient competitive entry and relieved Ellerbe from the responsibility of performing TELRIC compliant cost studies. Having done so, the Commission did not intend for its exemption of Ellerbe from the necessity of producing a TELRIC-compliant cost study to mean that Ellerbe must still utilize TELRIC-compliant rates. Instead, the Commission determines that the rates should, to the extent practicable, reflect the costs and manner in which Ellerbe is providing service. Randolph's cost study provides a reasonable and cost effective surrogate for the cost and manner in which Ellerbe is providing service. For these reasons, Ellerbe is justified in using Randolph's cost study with the adjustments herein identified as a surrogate despite the differences in Randolph's and Ellerbe's sizes and that fact that Randolph's study is based upon NECA averages, which are not based strictly upon forward looking cost data.

CONCLUSIONS

The Commission concludes that it is reasonable and appropriate for Ellerbe to adopt Randolph's alternative cost study results with the adjustments herein identified.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

ISSUE NO. 26 - MATRIX ISSUE NO. 27: Do the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159 require the RLECs to use forward-looking costs in all facets of their alternative cost studies, without regard to practicality or feasibility?

POSITIONS OF PARTIES

RLECs: No. The Commission adopted the Public Staff's recommended Guidelines for alternative cost studies in Docket No. P-100, Sub 159. The Public Staff recommended that the cost data used be forward-looking only "to the extent practicable" or "feasible." The RLECs' costs studies met that standard.

CMRS PROVIDERS: The *Modification Order* requires that the RLECs' cost data should be forward-looking "to the extent practicable." The term practicable means "capable of being effected, done, or executed." It was practicable for the RLECs to have used FCC switch cost data or to inquire about switch costs from vendors, but they did not do so.

PUBLIC STAFF: No. The alternative cost study Guidelines do not require the RLECs to use forward-looking costs in all facets of their alternative cost studies.

DISCUSSION

The CMRS Providers' argument was, in essence, that the RLECs' studies have overstated switch costs because they have used embedded data. The CMRS Providers contended that switch costs have been declining and that the RLECs should have used FCC switch cost data or asked for vendor quotations, neither of which the RLECs did. According to the CMRS Providers, these were "practicable" steps the RLECs could have taken.

The RLECs replied that the CMRS were, in essence, trying to read in a TELRIC requirement for the RLEC cost studies, when that was precisely what the *Modification Order* provided that the RLECs did not have to do when the Commission granted the Section 252(f)(2) exemption. The cost study Guidelines are not the same or similar to TELRIC. As such, the alternative cost study guidelines do not preclude the use of embedded cost data. The RLECs also argued that switch costs stopped decreasing in 2003 and started increasing in January 2006.

The Public Staff emphasized that the purpose of the relief given in the Docket No. P-100, Sub 159 proceeding was that the RLECs were not to be required to use forward-looking costs for all facets of their studies. The Commission determines that it declines to adopt the CMRS Providers' position because the Commission has granted TELRIC relief to the RLECs in Docket No. P-100, Sub 159.

In the *Modification Order* in Docket No. P-100, Sub 159, the Public Staff proposed, the RLECs accepted, and the Commission promulgated a set of Guidelines for the use of the RLECs in producing alternate studies for the calculation of reciprocal compensation rates. Guideline No. 2 provided that "[t]he cost data may be a surrogate of the company's cost, but should be forward looking and reflect an efficient network *to the extent practicable*." (Emphasis added). The granting of the Section 251(f)(2) exemption and the promulgation of the Guidelines occurred within the context of a proceeding in which the RLECs sought modification of their reciprocal compensation duties pursuant to Section 251(b)(5). The relief that the RLECs sought was an exemption from the duty to perform TELRIC studies and the attendant responsibility that all costs should be forward-looking in order to establish a reciprocal compensation rate. In granting this relief, the Commission observed:

> It is obvious from the evidence that the Rural ICOs are very small ILECs with limited subscriber bases and limited resources for dealing with the demands that much larger and more sophisticated ILECs must meet. Indeed, this type of disparity is the very reason that Congress rejected a "one size fits all" approach when it made available to rural carriers a process for exemptions, suspensions, and modifications from certain Section 251 duties to Section 251(f)(1) and (2). (*Modification Order* at 13)

The recommendation of the Public Staff, which was adopted by the Commission, was that forward-looking costs in the alternative cost study were to be used only to the extent feasible or practicable. Thus, the Public Staff's alternative cost study Guideline recommendations clearly recognized that costs would not necessarily be forward-looking for all facets of the study. Nevertheless, in essence, the CMRS Providers argue that, because the RLECs are said to be *capable* of producing such a study, the RLECs are required to produce studies based on forward-looking elements.

In any event, with respect to *this* issue, it is not necessary for the Commission to decide how forward-looking the RLECs' studies should practicably be. The Commission determines that it is self-evident from this issue *as worded* compared to Guideline No. 2 *as worded* that the RLECs are not required to use forward-looking costs "in all facets of their alternative costs studies, without regard to practicality or feasibility." The Commission also notes that an opposite ruling would tend to be at variance with the Commission's goal in that Order of granting the Section 251(f)(2) exemption to enable the RLECs to avoid the expense and effort necessary to provide a TELRIC-compliant study.

CONCLUSIONS

The Commission concludes that the alternative cost study Guidelines adopted by the Commission in Docket No. P-100, Sub 159 do not require the RLECs to use forward-looking costs in all facets of their alternative cost studies.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

ISSUE NO. 27 - MATRIX ISSUE NO. 28: Does the alternative cost study Guideline established by the Commission in Docket No. P-100, Sub 159 that provides for usage-based rates require those rates be based on usage-sensitive costs determined in accordance with the FCC TELRIC rules?

POSITIONS OF PARTIES

RLECs: No. While the Commission's Order in Docket No. P-100, Sub 159 required RLECs to develop usage based rates, it did not require them to develop their rates based on usage sensitive costs or in accord with other of the FCC's TELRIC requirements.

CMRS PROVIDERS: Guideline No. 1 requires that cost data "reflect only the direct costs associated with the transport and termination of traffic," while Guideline No. 3, which requires that rates be "usage based," means that the costs must be usage-sensitive in light of the direct cost requirement. Furthermore, Section 252(d) of the Act allows the RLECs to recover only the "additional" costs of transporting and terminating CMRS traffic, meaning, according to the FCC, only the recovery of usage sensitive costs. Under the Act, the RLECs cannot be exempted from this standard.

PUBLIC STAFF: The usage-based rates for reciprocal compensation should reflect the direct costs associated with the transport and termination of local traffic.

DISCUSSION

This issue concerns the principles for the determination of the costs associated with the end office switch that should be included in the termination rate component of reciprocal compensation. The conclusions from these principles can be very contentious.[1] To make an appropriate conclusion, one must consider how the Act addresses charges for the transport and termination of traffic when read together with the cost study Guidelines.

The Act addresses charges for the transport and termination of traffic[2] in Section 252(d)(2)(A), the most important subsection being for the purposes of this issue Section 252(d)(2)(A)(ii), which reads: "[A] State commission shall not consider the terms and conditions for reciprocal compensation to be just and reasonable unless . . . (ii) such terms and conditions determine such costs on the basis of a reasonable approximation of the *additional* costs of terminating such calls." (Emphasis added) Notably, this particular standard is *not* subject to exemption under Section 251(f)(2) or Section 251(f)(1), and the standards apply whether the study involves TELRIC or embedded cost.

The FCC in its *Interconnection Order* concluded in Paragraph 1057 that the "additional cost" to the LEC of terminating a call that originates on a competing carrier's network as primarily consisting of the traffic-sensitive component of local switching. The FCC continued: "The network elements involved with the termination of traffic include the end-office switch and local loop. The costs of local loops and line ports associated with local switches do not vary in proportion to the number of call terminated over these facilities. We conclude that such non-traffic sensitive costs should not be considered 'additional costs' when a LEC terminates a call that originated on the network of a competing carrier." The FCC also noted in Paragraph 1059 that it sought to address the impact on small ILECs and noted that small ILECs either enjoyed relief from certain FCC rules under Section 251(f)(1) or could seek relief under Section 251(f)(2). In Docket No. P-100, Sub 159, the RLECs received relief from having to apply TELRIC standards with respect to the calculation of reciprocal compensation.

Guideline Nos. 1 and 3 in the *Modification Order* are also pertinent. Guideline No. 1 provides that "[t]he cost data should be easily obtainable, verifiable, and *reflect only the direct costs associated with transport and termination of traffic.*" Guideline No. 3 provides that "[t]he rates for transport and termination of traffic should be *usage based.*" (Emphases added).

Read together, these provisions determine what costs are recoverable through the reciprocal compensation rate. They are the bases that the RLECs must use in determining what direct costs are to be included in calculating the reciprocal compensation rate. Specifically,

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[1] As usual, the proportion of the end office switch that is not traffic sensitive was contentious. There was considerable testimony about the amount of switch investment that should be considered to be traffic sensitive. RLEC witness Schoonmaker testified that the FCC allows rural carriers to treat 70% of switching costs as usage sensitive, while witness Conwell testified that little, if any, local switching costs are usage sensitive. He believed that 63% of MebTel's switch costs were not traffic-sensitive. Witness Skrivan testified that *all* of the switch costs should be included in the calculation of the termination component of the reciprocal compensation rate and that the termination rate is much like the unbundled network element for switching.

[2] "Transport" is defined by the FCC in §51.701(c) as the "transmission and any necessary tandem switching of telecommunications traffic subject to Section 251(b)(6) of the Act [reciprocal compensation] from the interconnection point between the two carriers to the termination carrier's end office that directly serves the called party, or equivalent facility provided by a carrier other than an incumbent LEC." "Termination" is defined in §51.701(d) as "the switching of telecommunications traffic at the terminating carrier's end office switch, or equivalent facility, and the delivery of such traffic to the called party's premises."

reading Section 252(d)(2)(a)(ii) [referring to "additional costs of terminating such calls"], together with the FCC commentary, Guideline No. 1 [cost data to reflect only "direct costs associated with transport and termination of traffic"] and Guideline No. 3 ["rates for transport and termination should be usage based"], the Commission determines that these provisions lead ineluctably to the conclusion that only the traffic-sensitive costs of a switch satisfy the requirements for direct, additional, and usage-based costs associated with terminating local traffic and hence recoverable through reciprocal compensation rates. This conclusion is consistent with Finding of Fact No. 10 (MebTel) and Finding of Fact No. 17 (Randolph) herein. The appropriate levels of traffic (or usage) sensitive costs to be included in the RLECs' alternative cost studies are discussed in Findings of Fact Nos. 10 and 17.

CONCLUSIONS

The Commission concludes that only the traffic-sensitive costs of a switch comprise the direct costs associated with terminating local traffic and should be recouped through reciprocal compensation rate. The non-traffic sensitive component of end office switches is necessary regardless of whether local traffic is routed through the switch.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

ISSUE NO. 28 - MATRIX ISSUE NO. 29: Do the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159 require that central office investments (except for trunk equipment) be excluded from the RLECs' alternative cost studies?

POSITIONS OF PARTIES

RLECs: No.

CMRS PROVIDERS: Yes. Guideline No. 1 requires that cost data "reflect only the direct costs associated with transport and termination." All switch investments and costs, except those of interoffice trunk equipment, should be excluded from transport and termination rates. The RLECs have made numerous costs overstatements.

PUBLIC STAFF: The Public Staff believes that only the direct costs of switching attributable to termination should be recoverable through the reciprocal compensation rate.

DISCUSSION

The analysis of this issue is similar to that of Matrix Issue No. 28 — that is, pursuant to Section 252(d)(2)(A)(ii), which provides that reciprocal compensation costs are to be calculated on the basis of a reasonable approximation of the additional costs of terminating such calls, and the applicable Guidelines approved in the *Modification Order*, only the direct costs of switching attributable to termination should be recoverable through the reciprocal compensation rate.

The Commission has historically adopted rates for unbundled network switching that reflect separate rates for the traffic-component of the end office switch and of that portion of the switch that is not traffic-sensitive. After noting that the non-price plan companies are permitted to use an allocation of 30% as the portion of the switch that is considered to be non-traffic sensitive, witness Schoonmaker observed that this portion is then allocated to the common line component for cost recovery purposes. He further testified that the FCC rules treat line port equipment costs as not includible in the determination of the transport and termination rate.

In view of the above, it follows that only the direct costs for central office investments associated with the *additional* cost of terminating local traffic should be included in the RLECs' alternative cost studies—that is, the part of the switch that is considered to be traffic-sensitive and not associated with the line port.

CONCLUSIONS

The Commission concludes that only the direct costs for central office investments associated with the additional cost of terminating local traffic should be included in the RLECs' alternative cost studies—that is, the part of the switch that is considered to be traffic-sensitive and not associated with the line port.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27, 28, and 29

ISSUE NOS. 29-31 - MATRIX ISSUE NOS. 30-32:

Matrix Issue No. 30: Is Mebtel's alternative cost study consistent with the alternative cost study Guidelines established by the Commission in Docket No. P-100 Sub 159?

Matrix Issue No. 31: Does Randolph's alternative cost study based on interstate average schedule costs comply with the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159?

Matrix Issue No. 32: Is Ellerbe's proposed adoption of Randolph's cost study as a surrogate for Ellerbe's costs consistent with the alternative cost study Guidelines established by the Commission in Docket No. P-100, Sub 159?

POSITIONS OF PARTIES

RLECs: Matrix Issue No. 30: Yes, as shown in the direct and rebuttal testimony of witness Skrivan and in the response to Matrix Issue Nos. 17 through 21.

Matrix Issue No. 31: Yes, as shown in the direct and rebuttal testimony of witness Schoonmaker.

Matrix Issue No. 32: Yes, the Public Staff's recommended Guidelines allowed the usage of cost data that "may be a surrogate of the company's cost."

CMRS PROVIDERS: Matrix Issue No. 30: No. The MebTel study fails to comply with the Guidelines for the reasons given and the corrections recommended for Matrix Issue Nos. 17 through 21.

Matrix Issue No. 31: No. The Randolph study fails to comply with the Guidelines for the reasons given and the corrections recommended for Matrix Issue Nos. 22 through 25D.

Matrix Issue No. 32. No. Ellerbe's network is sufficiently different from Randolph's network to result in different transport and terminations costs as described in Matrix Issue No. 26. A company-specific costs study is required. Witness Conwell produced an estimate of Ellerbe's transport and termination costs and a company-specific rate.

PUBLIC STAFF: Matrix Issue No. 30: No, but with adjustments and modifications to the study, the alternative cost study can become consistent with the Commission's alternative cost study Guidelines.

Matrix Issue Nos. 31 and 32: No, but with adjustments and modifications to the study, the alternative cost study can become consistent with the Commission's alternative cost study Guidelines and is an adequate surrogate for Ellerbe.

DISCUSSION

There can be no question that the RLECs were authorized to adopt cost studies that are not TELRIC-compliant, so long as they followed the Guidelines set forth in the Commission's *Modification Order*. The seven Guidelines set forth by the Commission provide that an alternative cost study must use cost data that are obtainable and verifiable and include only the direct costs associated with the transport and termination of local traffic. Furthermore, the costs may be a surrogate of the company's cost but should be forward-looking and should reflect an efficient network to the extent practicable. The rates should be usage-based. Other criteria in the Guidelines are that the capital costs and structure should reflect those previously approved by the Commission in Docket No. P-100, Sub 133d and that depreciation should be in accordance with FCC Guidelines for economic lives and net salvage value. Finally, the study should include a reasonable allocation of common costs and exclude retail costs.

Each RLEC adopted a different method of calculating its recommended reciprocal compensation rate. For example, the approach taken by Ellerbe was to adopt the study and rates that were being proposed by Randolph. This is permissible under Guideline No. 2 which allows a company to use surrogate cost data. To the extent that adjustments are made to Randolph's study, similar adjustments would need to be made to Ellerbe's.

MebTel, a cost company, adjusted its interstate Part 36 and Part 69 separation studies to calculate the reciprocal compensation rate it proposed. MebTel made various adjustments to make its study forward-looking. These adjustments included costs of capital and depreciation rates to comply with the Commission's Guidelines. MebTel based its per-minute rate upon a forward-looking estimate of usage on its network.

Randolph, an average schedule company, used certain average schedule formulas for recovery of the costs associated with transport and termination of local traffic. Witness Schoonmaker testified that the study for Randolph was based upon NECA traffic-sensitive formulas related to the transport and termination of traffic. The specific formulas used by witness Schoonmaker were approved by the FCC for settlement from July 1, 2006, through June 30, 2007. He modified the average schedule formulas to reflect forward-looking demand and access lines for Randolph and limited the formulas to those used for the transport and termination of traffic.

While the three RLECs adopted different methods to determine their proposed reciprocal compensation rates, the Commission concludes that each generally complies with the Guidelines established in Docket No. P-100, Sub 159. However, the cost studies of MebTel and Randolph have shortcomings that, without adjustments, fall short of the Commission's Guidelines for determining the reciprocal compensation rate.

CONCLUSIONS

In the Evidence and Conclusions for Findings of Fact Nos. 7 through 10, the Commission addressed the CMRS Providers' objections to the alternative cost study filed by MebTel. In its conclusions for these findings, the Commission indicated what adjustments or changes to the study are required to meet all of the Guidelines established in Docket No. P-100, Sub 159. Once these adjustments are made, the Commission determines that MebTel's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. Likewise for Randolph's study, the Commission has addressed objections raised by the CMRS Providers in the Evidence and Conclusions for Findings of Fact Nos. 11 through 22. The Commission has spelled out the adjustments necessary to meet the Guidelines it established in Docket No. P-100, Sub 159. Once these adjustments are made, the Commission determines that Randolph's alternative cost study will meet the Guidelines established in Docket No. P-100, Sub 159. By the same token, Ellerbe should make similar adjustments.

IT IS, THEREFORE, ORDERED as follows:

1. That the RLECs and the CMRS Providers shall prepare and file a Composite Agreement in conformity with the conclusions of this *Order* no later than Monday, February 4, 2008. 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*), and as amended by the Commission's *Order Modifying Composite Agreement Filing Requirements* dated November 3, 2000.

2. That, not later than Tuesday, January 22, 2008, a party to the arbitration may file objections to this *Order* consistent with paragraph 3 of the *Arbitration Procedure Order.*

3. That, not later than Tuesday, January 22, 2008, 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 the objections or comments of any party or person who has not submitted such executive summary or whose executive summary is not in substantial compliance with the requirements above.

5. That parties or 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, on an MS-DOS formatted 3.5-inch computer diskette containing noncompressed files created or saved in Microsoft Word.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of December, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Chairman Edward S. Finley, Jr. dissents on Findings of Fact Nos. 1 and 2.

bp122007.01

Appendix A
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RLECs/CMRS Providers Arbitration Proceeding
Docket No. P-21, Sub 71
Docket No. P-35, Sub 107
Docket No. P-61, Sub 95

Act	Telecommunications Act of 1996
ALLTEL	ALLTEL Communications, Inc.
ARMIS	Automated Reporting Management Information System
AT&T	BellSouth Telecommunications, Inc., d/b/a AT&T North Carolina
Cingular	New Cingular Wireless, LLC, d/b/a Cingular Wireless
CLEC	Competitive Local Exchange Company (Carrier)
CLP	Competing Local Provider
CMRS	Commercial Mobile Radio Service
CMRS Providers	ALLTEL and Cingular
Commission	North Carolina Utilities Commission
CPR	Continuing Property Record
DLC	Digital Loop Carrier
Ellerbe	Ellerbe Telephone Company
FCC	Federal Communications Commission
HAI	The Hatfield Model
ICOs	Independent Telephone Companies
ILEC	Incumbent Local Exchange Company (Carrier)
IXC	Interexchange Carrier

LSS	Local Switching Support
MAG Plan	Multi-Association Group Plan
MebTel	MebTel, Inc.
MOU	Minute of Use
MTA	Major Trading Area
NECA	National Exchange Carriers Association
POI	Point of Interconnection
Public Staff	Public Staff – North Carolina Utilities Commission
Randolph	Randolph Telephone Company
RAO	Recommended Arbitration Order
RBOC	Regional Bell Operating Company
RLECs	Rural Local Exchange Companies – i.e., Ellerbe, MebTel, and Randolph

Appendix A
Page 2 of 2

Sprint PCS	Sprint Spectrum LP, as an agent for SprintCom, Inc., d/b/a Sprint PCS
SunCom	SunCom Wireless Operating Company, LLC
TA96	Telecommunications Act of 1996
TELRIC	Total Element Long Run Incremental Cost
UNE	Unbundled Network Element
UNE-P	Unbundled Network Element – Platform

Chairman Edward S. Finley, Jr., dissents from Finding of Fact Nos. 1 and 2 and the resolution of Matrix Issues 1 and 4.

The landline and wireless carriers subject to this arbitration have agreed to interconnect their networks to permit the exchange of local calls. One method of interconnection is classified as "indirect." Rather than interconnecting landline and wireless networks directly at an interconnection point where the landline facilities and wireless facilities physically meet one another, both parties instead rely upon the facilities of an intermediate carrier for a part of the originating transport. In such cases of indirect interconnection, no single point of interconnection between the originating and terminating carrier exists. Instead, for each call, there are two points of physical interconnection, one between the originating carrier and the intermediate carrier, and a second between the intermediate carrier and the terminating carrier. The intermediate carrier assesses a per minute charge for the use made of its network to enable the landline and wireless carriers that have chosen not to interconnect directly to originate and terminate calls.

The dispute with respect to Findings of Fact 1 and 2 and matrix issues 1 and 4 is whether the landline or wireless carrier should bear responsibility for these transit charges for calls originating on the landline network and terminating on the wireless network. The wireless carriers have agreed that payment of the transit charges for local calls originating on their networks is a transport cost for which they are responsible in delivering the local call to the terminating landline network. The landline carriers, however, dispute that the transit charges assessed by the intermediate carrier on calls originating on the landline carriers' network are costs they should bear in delivering the calls to the terminating wireless carrier's network. The landline carriers argue that the wireless carriers should bear 100% of the transit charges on all calls exchanged between them that transverse the intermediate carrier's facilities irrespective of the network on which the calls originate or terminate.

Reciprocal compensation is the cost reimbursement mechanism authorized in TA96 through which the originating carrier compensates the terminating carrier for the service the terminating carrier provides to enable subscribers of the originating network to complete calls on the terminating carrier's network. The originating carrier charges the originating subscriber for making the local call, and unless the originating carrier compensates the terminating carrier for the use of the terminating facilities to complete the call, the terminating carrier goes uncompensated for the service it provides. First Report and Order, FCC 96-325, CC Docket No. 96-98, 95-185. ¶ 1034 (Aug. 8, 1996)

Consequently, a fundamental principle the FCC has relied upon in implementing reciprocal compensation is that the originating carrier bears all the costs in delivering the local calls initiated by its subscribers to the network of the terminating local carriers. The wireless carriers rely on this fundamental principle in support of their position that the landline carriers should bear responsibility for the transit charges on landline originated calls delivered to the wireless network via the interconnection with the intermediate carrier. The wireless carriers view the transit charges as costs of originating transport even though borne indirectly as charges from the intermediate carrier and even through assessed for services rendered outside the network of the originating carrier.

The landline carriers make several arguments in opposition to the principle that the originating carrier pays and in support of their position that the wireless carriers should pay all the transit charges irrespective of whose subscriber initiates the call. One argument is that the wireless carrier has chosen indirect interconnection, rather than direct interconnection, so the wireless carrier should bear the financial responsibility for this choice. The landline carriers graphically accuse the wireless carriers of "hiding behind" the intermediate carrier's switch in furtherance of their own financial self interest.

The record evidence fails to support this argument. Presumably, the choice to route landline and wireless originated traffic through the tandem of the intermediate carrier is the least expensive choice based on the volume of traffic involved. The pro competitive intent of TA96 is not furthered by arbitration decisions that shift all transit charges to the new entrant carriers as punishment for failure to install more costly facilities for direct interconnection so transit charges can be avoided. The issue is which carrier should bear responsibility for transit charges on landline originated calls. Any choices the wireless carriers made in routing wireless originated calls to the landline network is not at issue. The wireless carriers have voluntarily agreed to bear responsibility for transit charges on calls originated on their network. The wireless carriers accept responsibility for the costs incurred resulting from their choices in delivering calls to the landline networks.

Both the wireless and landline witnesses verify that the choice of means of delivery of landline originated calls rests with the landline carriers. See, e.g., Tr. Vol. 1, pp. 113, 115, 120. The landline carrier can interconnect directly with the wireless carrier even if the wireless carrier chooses indirect interconnection for wireless originated calls.

The second argument of the landline carriers is that they cannot be required to pay costs incurred outside their networks. This argument is equally meritless. With the advent of local competition, calls originating on an incumbent carrier's network routinely terminate on the network of a competing local carrier. The incumbent carrier must pay the terminating carrier reciprocal compensation for the service the terminating carrier provides outside the incumbent's network. One element of costs recouped through reciprocal compensation is transport costs. If the landline carriers must pay reciprocal compensation to reimburse for transport costs incurred beyond their network boundaries, no reason exists why they should not pay transport costs incurred beyond their network boundaries to deliver calls to the wireless carrier's facilities. As indicated below, federal jurisdictions have ruled that wireless carriers may shift costs of transit charges on landline originated calls to the originating landline carriers.

The primary argument of the landline carriers is that 47 U.S.C. § 251(c)(2)(B) insulates them for any responsibility to pay for costs incurred to transport calls originating on their networks (other than reciprocal compensation) outside the boundaries of their network. 47 U.S.C. § 251(c)(2)(B) provides:

> In addition to the duties contained in subsection (b) of this section, each incumbent local exchange carrier has the following duties:
>
> > The duty to provide for the facilities and equipment of any requesting telecommunications carrier interconnection with the local exchange carrier network at any technically feasible point within the carrier's network.

The landline carriers rely upon this requirement of the Act that imposes upon them an obligation to provide a physical interconnection within their networks to a requesting competing carrier as a protection against the incurrence of any costs in transporting calls initiated by their subscribers they incur in delivering the calls to the wireless carriers' facilities if those facilities are located outside the landline carrier's network. They urge this position even if the choice for the method of delivering traffic in that manner is the choice of the landline carrier. The logic behind this argument that converts a duty into a protection fails.

The language of the statute and the regulations promulgated thereunder certainly cannot be read to provide the protection the landline carriers claim. The landline carriers "interpret" the requirement, however, to support their position. Their argument focuses on the "within the carrier's network" phrase. The landline carriers argue that they only are obligated to provide a single interconnection point to a requesting competitive local carrier within their network, so their responsibility to bear transport costs to deliver calls originating from their subscribers to customers of competing carriers cannot extend beyond the single physical interconnection point. The landline carriers argue that their obligation ends at the physical interconnection on their network irrespective of their agreement to exchange local traffic indirectly through the facilities of an intermediate carrier so that the terminating competing carrier actually receives the call at its interconnection with the intermediate carrier beyond the landline carrier's network.

As indicated above, the parties have agreed to indirect interconnection through the intermediate carrier's tandem. Such tandem by definition is not on the landline carrier's network. The notion of the existence of only a single physical point of interconnection with the landline carriers is a fiction artifically relied upon to shift financial responsibility for transit charges to the terminating carrier. As the landline carriers are not complying with a request for interconnection on their network with the competing carrier, they are not even acting in compliance with their obligations under § 251(c)(2)(B). They voluntarily have agreed with indirect interconnection. They have waived the right to insist on any implicit protection connected with compliance with their 251(c)(2)(B) obligation. The wireless carriers have requested interconnection at the intermediate carrier's tandem outside the landline carrier's network, and the landline carrier has agreed. No request pursuant to 47 U.S.C. § 251(c)(2)(B) has been made.

Section 251(c)(2)(B) imposes an obligation on incumbent carriers. It does not bestow on them rights and privileges. Upon passage of the Act in 1996 the incumbents enjoyed a monopoly that Congress chose to replace with competition. Section 251(c)(2)(B) imposed obligations on the incumbent monopolists and rights and privileges on the new entrants, not vice versa.

Aside from the inherent lack of merit in the landline carriers' argument, the federal courts that have directly addressed this interpretation have rejected it, and, based on the submissions in this arbitration, a majority of state commissions have agreed with the federal court interpretation. The favored and correctly reasoned interpretation now is that the section of TA 96 that controls the outcome of this dispute is 47 U.S.C. § 251(a), which imposes on each telecommunications carrier "a duty to interconnect directly or <u>indirectly</u> with the facilities and equipment of other telecommunication carriers", not § 251(c)(2) (emphasis added).

In <u>Atlas</u> <u>Telephone</u> v. <u>Oklahoma</u> <u>Corporation</u> <u>Comm</u>., 400 F.3d 1256 (10th Cir. 2005) the rural local exchange carriers (RLECs) argued that they could not be forced to bear the additional expense of transporting traffic bound for a CMRS across the SWBT (intermediate carrier) network on the theory that the RLECs only were responsible for transport to a point of interconnection on their own network. The Tenth Circuit rejected this argument, holding that "because we hold that 47 U.S.C. § 251(c)(2) does not govern interconnection for purposes of local exchange traffic, the RTC's argument that CMRS providers must bear the expense of transporting RTC-originated traffic on the SWBT network must fail." 400 F. 3d at 1266, n. 11.

The Tenth Circuit explained its ruling:

> The RTCs contend that the general requirement imposed on all carriers to interconnect "directly or <u>indirectly</u>," 47 U.S.C. § 251(a) (emphases added), is superseded by the more specific obligations under § 251(c)(2). Yet, as noted above, the obligation under § 251(c)(2) applies only to a far more limited class of ILECs, as opposed to the obligation on all telecommunications carriers under §251(a). The RTC's interpretation would impose concomitant duties on both the ILECs and the <u>requesting</u> carrier. That

> contravenes the express terms of the statute identifying only ILECs as entities bearing additional burdens under §251(c). We cannot conclude that such a provision, embracing only a limited class of obligees, can provide the governing framework for the exchange of local traffic.

400 F. 3d at 1265.

Recent state commission decisions adopt and follow the holding of Atlas Telephone. Order of Arbitration Award, Tennessee Regulatory Authority. Docket No. 03-00585, January 12, 2006, p. 30 ("if a call originates in a switch on one party's network, then the party is responsible for the transiting costs"); Florida Public Service Commission Order No. PSC-06-0776-FOF-TP in Docket Nos. 05-0119-TP and 05-0125-TP, issued September 18, 2006, p. 21 ("The Record evidence is persuasive that the originating carrier utilizing BellSouth's transit service is responsible to compensate BellSouth for that service"); Order on Clarification and Reconsideration, Georgia Public Service Commission, Docket No. 16772-U, released May 2, 2005, pp. 3-4. ("In Atlas, the Tenth Circuit concluded that commercial mobile radio service providers should not have to bear the cost of transporting calls that originate in the networks of rural telephone companies. . .. The Commission finds the reasoning of Atlas compelling.")

The United States Court of Appeals for the District of Columbia Circuit reached a similar result in Mountain Communications, Inc. v. Federal Communications Commission, 355 F.3d 644 (D.C. Cir. 2004). The D. C. Circuit ruled that Qwest, the ILEC, could not assess charges against Mountain, a paging carrier, for calls originating with Qwest subscribers that Qwest delivered to Mountain's single POI within a LATA in Colorado where the POI was not within the boundaries of the originating subscriber's local calling area and where Mountain delivered the call to its paging subscriber within the LATA. Relying upon TSR Wireless, LLC v. U. S. West Communications, Inc., 15 FCCR 11166, 11184 ¶ 31 (2000), aff'd Qwest v. FCC, 252 F.3d 462 (D.C. Cir. 2000), 47 C.F.R. §§ 51.703(b) and 51.701(b)(2), the Court prevented Qwest from assessing the charge.

In TSR the FCC ruled that "[s]ection 51.703(b), when read in conjunction with Section 51.701(b)(2), requires LECs to deliver, without charge, traffic to [wireless] providers anywhere within the MTA [Major Trading Area] in which the call originated. . ." TSR, 15 FCCR at 11184 ¶ 3.

Also at issue in Mountain was whether Qwest could charge Mountain transit charges for delivering calls to Mountain initiated by subscribers of third party carriers. The FCC had ruled that Qwest could charge Mountain for the transit service but indicated that Mountain could seek reimbursement from the originating carrier. The issue became moot at oral argument. Nevertheless, the Court stated, "In any event, by indicating that Mountain could charge the originating carrier, it [the FCC] suggested that Mountain was essentially correct in claiming that the originating carrier should bear all the transport costs." 355 F.3d at 649 See, also, Texcom v. BellAltantic Corp. Order on Reconsideration, March 27, 2002, FCC 02-96 (intermediate carrier can assess transit charges to terminating wireless carrier, but wireless carrier can seek reimbursement from originating carrier).

Were the Commission's decision on these issues to be based solely on the evidence of record and the authorities cited from other jurisdictions, there should be no question that the wireless carriers should prevail. The complicating factor, however, is the Commission's October 8, 2004 Recommended Arbitration Order in Docket No. P-118, Sub 130, a case involving Verizon Wireless and Alltel addressing similar issues.

The holding of the Commission in that docket is:

> For this reason, the Commission believes it should apply the holding and reasoning of the Fourth Circuit opinion regarding direct interconnection and find that the originating carrier is responsible, both technically and financially, for transporting calls to the POI [which must be located on the landline carrier's network]; that the terminating carrier is responsible, in the first instance, for the cost of completing the call beyond the POI, and that the originating carrier must pay reciprocal compensation to the terminating carrier to reimburse the terminating carrier for those call completion costs.

The justification for this holding is difficult to discern from the Commission's discussion, and the holding is not supported by the authorities cited. The Commission cited MCIMetro Access Transmission Servs. v. BellSouth Telecommunications Inc., 352 F.3d 872 (4th Cir., 2003) as the primary authority for its decision. MCIMetro, however, supports the wireless position on the issues in dispute in these arbitrations, not the rural landline carriers'. The issue in MCIMetro was whether BellSouth, the incumbent, or MCIMetro, the competing local exchange carrier, should bear financial responsibility for the cost of transporting traffic originating on BellSouth's network beyond the boundary of the local calling area to a distant point of interconnection between BellSouth and MCI selected by MCI as permitted by 47 U.S.C. 251(c)(2)(B). The Fourth Circuit ruled that BellSouth must bear these transport costs. The Fourth Circuit based its decision on 47 U.S.C. 251(b)(5) and 47 C.F.R. § 51.703(b). Section 703(b) states: "[a] LEC may not assess charges on any other telecommunications carrier for telecommunications traffic that originates on the LEC's network." The Fourth Circuit ruled "Rule 703(b) is unequivocal in prohibiting LECs from levying charges for traffic originating on their own networks, and, by its own terms, admits no exceptions." 352 F.3d at 881.

The Fourth Circuit rejected BellSouth's argument that BellSouth should be permitted to shift its transport costs to MCI because MCI had chosen the distant point of physical interconnection pursuant to 47 U.S.C. 251(c)(2). The Fourth Circuit ruled that the dispute appropriately should be resolved under section 251(b) of the Act as a dispute over reciprocal compensation. The Fourth Circuit, like the Tenth Circuit, stressed that section 251(c) deals solely with obligations imposed on incumbents and therefore is not authority under the Act for imposing costs on competitive carriers. 352 F. 3d at 874-75. MCIMetro is not appropriate authority for a decision requiring the competitive wireless or landline carriers to bear financial responsibility for transit costs on incumbent originated traffic.

The other significant authority the Commission cites is 47 C.F.R. 51.305(a)(2). This rule repeats the requirement of section 251(c)(2)(B) obligating the incumbent to provide physical interconnection to the competing carrier on the incumbent's network at a technically feasible point. The Commission relies upon this rule for the proposition that the physical interconnection must be on the incumbent's network and that the incumbent's financial responsibility for incumbent originated traffic ends at this point of physical interconnection. The rule does not contain this requirement. Both the Fourth Circuit and the Tenth Circuit have ruled that the 251(c) interconnection requirements do not control in disputes over reciprocal compensation. No other authority is cited to support the conclusion the Commission reached in Alltel.

In Alltel the Commission stated that it preferred a result contrary to the ruling it concluded to be required by the interpretation of the authorities it cited. "The Commission believes the POI outside ALLTEL's network that was originally proposed by Verizon Wireless may be practical and preferred by both parties over the result the Commission believes is compelled by a strict application of the relevant FCC rules."[1]

Unfortunately, the Commission was following a strict application of an FCC rule that addresses an incumbent's duty to interconnect, not the rules addressing financial responsibility for incumbent originated calls that terminate on a competing carrier's network. To the extent the ruling in Alltel was permissible before Atlas, it should not be permissible now. Ample controlling authority exists for the Commission to order the "practical and preferred result." To the extent reliance on Alltel stands in the way of a result that is both legally and practically necessary, the Commission should not be bound by it. At the least the full Commission should readdress the issue in the context of the law and evidence in this docket cited above. While the Commission should adhere to precedent in most circumstances, in this case significant federal authority dated subsequent to Alltel rejects the Alltel reasoning. In rendering arbitration decisions, the Commission is applying federal law, and in this case federal law is at odds with Alltel.

\s\ Edward S. Finley, Jr.
Chairman Edward S. Finley, Jr.

[1] The Commission ruled that it was without authority to require the rural landline carriers and the wireless carriers to interconnect indirectly beyond the landline carrier's network: "For two carriers to interconnect, either directly or indirectly, they must have a POI—that is, a point at which traffic is physically exchanged between the two carriers' networks. However, in defining the POI, the Commission does not have the authority to do what the parties are free to do by agreement, i.e., the Commission cannot define the POI to be of a point outside of the ALLTEL network." The Tenth Circuit in Atlas rejected this Commission determination as well. "The RTCs interpret 47 U.S.C. § 251(c) as imposing a requirement of direct connection on a competing carrier. We disagree. As detailed above, the affirmative duty established in § 251(c) runs solely to the ILEC, and is only triggered on request for direct connection. The physical interconnection contemplated by § 251(c) in no way undermines telecommunications carriers' obligation under § 251(a) to interconnect "directly or indirectly." 400 F. 3d at 1268.

DOCKET NO. P-35, SUB 96

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of MebTel, Inc. for Approval	)	ORDER CONCERNING
of a Price Regulation Plan Pursuant to	)	ACCESS TARIFF
N.C.G.S. 62-133.5(a)	)	

HEARD: Monday, March 26, 2007, in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William T. Culpepper, III, Presiding; Commissioners Robert V. Owens, Jr.; Sam J. Ervin, IV; James Y. Kerr, II; Howard N. Lee; and Edward S. Finley, Jr.

APPEARANCES:

FOR MEBTEL, INC.:

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FOR THE USING AND CONSUMING PUBLIC:

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BY THE COMMISSION: On March 9, 2007, the Public Staff filed a Motion asking that the Commission suspend a recent tariff filing by MebTel, Inc. (MebTel) and set it for investigation. In its February 28, 2007, filing, MebTel submitted tariffs and supporting documentation to revise the rates it charges for switched access service. Specifically, these changes would increase the rates for local transport, local switching, and line termination. MebTel also proposed to increase its terminating carrier common line (CCL) rate, which is charged to cover costs associated with the access line that connects the end user to MebTel's switch and is the only way wireline long distance calls can be completed to MebTel subscribers. The effect of the proposed rate increases is an increase in revenue to MebTel of approximately $203,000, or about 9.4% in MebTel's Interconnection Services category.

The Public Staff stated that it had reviewed the proposed tariffs for compliance with MebTel's Price Regulation Plan. It conceded that the increases are within the constraints allowed under the Plan, and the Service Price Index (SPI) is less than the Price Regulation Index (PRI) for the Interconnection Services category.

However, the Public Staff expressed several concerns regarding the increases proposed by MebTel such that approval of this tariff would not be in the public interest. First, the Public Staff stated that the increases proposed by MebTel would reverse the direction of access charge changes implemented under Commission directives or approval for the past twenty years. Similarly, the Federal Communications Commission (FCC) has been moving in that direction also. Increasing switched access rates in light of current industry trends would be shortsighted and unfair. Second, the Public Staff argued that MebTel's proposed rate increases are unreasonably discriminatory and anti-competitive because they provide incumbent local exchange companies (ILECs) with lower rates for terminating intraLATA traffic to MebTel subscribers while charging interexchange carriers (IXCs) more for the same service. Third, even if MebTel were to cure the discrimination problem, the Public Staff suggested that approval of MebTel's tariff would lead to higher rates throughout the state for consumers as LECs could be expected to increase the rates for both intraLATA toll calls as well as calls to exchanges included in Expanded Local Calling Area (ELCA) plans. Such increases would also be detrimental to the LECs' and competing local providers' (CLPs') efforts to remain competitive with wireless carriers.

On March 12, 2007, the Commission issued an Order Suspending Tariff and Scheduling Oral Argument and also required MebTel to file a Response to the Public Staff's Motion. The tariff in question was suspended for up to 45 days—that, is, until April 26, 2007.

<u>MebTel Reply</u>

On March 19, 2007, MebTel filed a Reply to the Public Staff's Motion.

First, MebTel noted that Section 5.A.(1) of its price regulation plan provides in pertinent part that a "tariff filing limited to a price change in an existing rate element shall only be investigated with regard to whether it is in compliance with Section 6 of this Plan." (Section 6 addresses pricing rules). Even the Public Staff has conceded that the increases fall within the constraints allowed under the Plan. Hence, MebTel has complied with Section 6 of the price regulation plan, and the Commission should conclude its investigation and allow MebTel's revised tariff to take effect.

Second, MebTel responded to various statements in the Public Staff's Motion. MebTel acknowledged that there had been a downward trend in access charges, but denied that this fact should affect whether MebTel is entitled to raise access charges under its price plan. Indeed, the downward trend in access charges is not universal: the National Exchange Carrier Association (NECA) recently sought increased interstate access charges, which became effective July 1, 2006. For similar reasons, speculation regarding the Missoula Plan is also irrelevant.

MebTel disagreed with the Public Staff that its access charge increases are "shortsighted and unfair," or that the access rate increases are unreasonably discriminatory or anticompetitive. MebTel met with the Public Staff prior to the filing of the tariff, and, when the Public Staff expressed concern about the proposed access rate element increases on the IntraLATA Toll Originating Responsibility Plan (ITORP), under which ILECs exchange intraLATA traffic, MebTel revised its original proposal to leave ITORP rates at their current level. In light of the concerns expressed by the Public Staff, MebTel said it is willing to increase its ITORP rates, but the Public Staff has already preemptively opposed such a move, saying that it fears higher rates for consumers. MebTel observed that the ability to raise rates under the Plan is an inherent feature of these Plans, and it noted that it would not be charging higher rates to consumers. MebTel stated that such increases would be up to the LEC or CLP serving end-users. MebTel also observed that the access rate structure under ITORP already makes provision for different access charge regimes between IXCs and ILECs.

MebTel rejected the Public Staff's view that increasing intrastate access charges would be detrimental to ILECs' and CLPs' efforts to remain competitive with wireless carriers. This argument is purely speculative and is premised on the invalid assumption that end-user pricing relates immediately and directly to intercarrier compensation rates. To be sure, there are adverse secular trends for traditional carriers, especially small ones, but this has nothing to do with MebTel's ability to revise access rate elements in conformity with its approved price plan.

Finally, MebTel noted that the Stipulation and Agreement between itself and the Public Staff stated that the parties agreed that, along with meeting the other statutory criteria under G.S. 62-133.5(c), MebTel's plan was "consistent with the public interest" and did not "unreasonably prejudice any class of telephone customers, including telecommunications companies." The Commission's October 24, 2006, Recommended Order concluded likewise.

Verizon Comments

On March 23, 2007, Verizon South, Inc., MCImetro Access Transmission Services LLC d/b/a Verizon Access Transmission Services and MCI Communications Services, Inc. d/b/a Verizon Business Services (collectively, Verizon) filed a Petition to Intervene and Comments in this docket. Verizon's Petition to Intervene was granted on April 3, 2007. In its Comments Verizon asked the Commission to reject MebTel's February 28, 2007, tariff filing to increase access rates, arguing that such an increase would not be in the public interest and would reverse the efforts of this Commission and the FCC to reform switched access pricing. MebTel should be looking to its end users, not other carriers, if it needs to increase revenues. If the Commission does not wish to deny MebTel's proposed increase outright, it should continue the tariff suspension and proceed with an investigation in which all interested parties may participate.

MebTel Reply to Verizon

On March 30, 2007, MebTel responded to Verizon's comments. MebTel stated that, while it did not object to Verizon's request to intervene, it believed that Verizon's comments assert matters which are irrelevant to the issue before the Commission and have no more merit than the quite similar arguments put forth by the Public Staff.

Oral Argument

An oral argument was held as scheduled on March 26, 2007, in which the Public Staff and MebTel participated. Both parties reiterated and expanded upon points made in their written filings and responded to Commissioners' questions. Much of the oral argument dealt with how various provisions of the price plan should be construed. Proposed Orders and Briefs were filed by the parties on April 20, 2007.

The Public Staff conceded that MebTel's proposed increase in access charges complied with the "mechanical" provisions of the price plan relating to pricing. However, the Public Staff noted that, while Section 5.A.(1) included a proviso that "a tariff filing limited to a price change in an existing rate element shall only be investigated with regard to whether it is in compliance with Section 6 of this Plan," Section 6.A.(8) also states as follows:

> (8) This Plan shall not operate to permit anticompetitive practices. The Company shall not engage in unlawful price discrimination, predatory pricing, price squeezing, or anticompetitive bundling or tying arrangements as those terms are commonly applied in antitrust law. Nor shall the Company give any unreasonable or unlawful preference or advantage to the competitive services of affiliated entities.

The Public Staff also noted the existence of Section 6.B.(3), which was inserted as a result of MebTel's acquisition of BellSouth Telecommunications, Inc.'s Milton and Gatewood exchanges in Docket No. P-35, Sub 101. The Public Staff suggested that this provision shows the Plan contemplates lower access charges. This provision states in pertinent part:

> (3) [H]eadroom created in the Interconnection Category by reductions in switched access rates may be transferred to the Moderate Pricing Flexibility Services Category without having to request Commission approval.

MebTel, on the other hand, pointed to various provisions of the Plan which, it maintained, contemplate that access charge rates are allowed to go up as well as down.
Such provisions include: Definition of "Multiplier" (use of a 1.5 factor in allowing category revenue increase for interconnection services), Definition of Price Regulation Index (allowing for increases), Section 6.A.(1) (allowing for interconnection services to increase by 1.5 times inflation), and Section 6.B.(4) (interconnection services "may be increased or decreased by varying amounts").

There was considerable discussion over whether the divergent rate increases applicable to ILECs under ITORP and those applicable to IXCs under access charges constituted unreasonable or unlawful discrimination. ITORP and access charges perform the same functions under a different rubric. MebTel noted that BellSouth charges an ITORP rate to other LECs that is greater than that to IXCs. MebTel's line of argument appeared to suggest that a distinction between LECs and IXCs with respect to the level of access charges is not in itself discriminatory. However, MebTel stated it willingness to equalize the rates if that would cure the discrimination concern.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that MebTel's Price Plan clearly allows for increases in access charges as long as MebTel has complied with the pricing provisions in the Plan under Section 6, including Section 6.A.(8). There is no question that MebTel has complied with the pure pricing, or "mechanical," part of Section 6. The sole question is whether the way in which MebTel has so structured its increase in access charges violates Section 6.A.(8), which does not allow the Plan "to operate to permit anticompetitive practices" nor to "engage in unlawful price discrimination, predatory pricing, price squeezing, or anticompetitive bundling or tying arrangements as those terms are commonly applied in antitrust law."

In the instant case, MebTel has so structured its increases that ILECs will be paying a lower rate than IXCs for an comparable service, but the Commission is unable to state, based on the record before it, that this constitutes a violation of the provisions of Section 6.A.(8). A differential between ITORP rates applicable to ILECs and access charges applicable to IXCs is not necessarily anticompetitive or unreasonably discriminatory. It is a matter of degree and of evidence. Finally, the Commission notes that, if the Commission were to find the IXC access rate anticompetitive, this might lead to the anomalous result that MebTel might be able under the pricing provisions of the Plan to simply *raise* another rate—that is, the ITORP rate—in order to cure the problem.

Accordingly, the Commission concludes that good cause exists to lift the suspension on MebTel's proposed tariff and allow it to go into effect.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of April, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Commissioner Lorinzo L. Joyner did not participate.

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DOCKET NO. P-55, SUB 1013

In the Matter of		
Application of BellSouth Telecommunications	)	ORDER RULING ON
Inc. for, and Election of, Price Regulation	)	AT&T'S REQUEST
	)	FOR REDUCTIONS IN
	)	FREE DIRECTORY
	)	ASSISTANCE
	)	ALLOWANCES

BY THE COMMISSION: On December 20, 2006, BellSouth Telecommunications, Inc. (hereinafter, AT&T[1]) filed a Request for Reductions in Free Directory Assistance Allowances (Request). By Order dated December 22, 2006, the Commission requested that the Public Staff and any other intervenors file comments by January 19, 2007, and that AT&T file reply comments by February 2, 2007, concerning the Request.

On January 19, 2007, initial comments were filed by Carolina Telephone and Telegraph Company and Central Telephone Company (collectively Embarq), the Public Staff, and Verizon South Inc. (Verizon). On January 25, 2007, the Public Staff – Communications Division filed a copy of an e-mail received by its office from a customer concerning AT&T's Request for inclusion in this docket. The customer stated that "[u]nless BellSouth and cell phone companies publish and distribute phone books containing these numbers, the free listing for those who do not have easy access to computers is necessary." On February 2, 2007, AT&T filed its reply comments.

REQUEST

AT&T requested, in its filing, that the Commission reduce the number of free local directory assistance allowances for both residence and business customers from four to three in the current Price Regulation Plan year; that an additional reduction in free call allowances from three to two be approved in the subsequent Plan year; and that the other allowances be eliminated on the basis of one per Plan year. AT&T also requested that the Commission allow AT&T the flexibility to move headroom in its Plan from the Moderate Flexibility Services Basket to the High Flexibility Services Basket to offset the revenue impact of reducing the allowances.

AT&T asserted that its customers are using competitive directory assistance alternatives. AT&T expressed the opinion that North Carolina consumers and businesses have numerous alternatives to AT&T's traditional 411 Local Directory Assistance service that include: (1) Pay-per-use directory assistance offered by competing local providers (CLPs) and wireless companies; (2) pay-per-use and free directory assistance offered by new competitive directory assistance companies; (3) Short Messaging Directory Services (SMS) offered by Internet and wireless companies; and (4) white and yellow page search engines offered by Internet

[1] By letter dated January 2, 2007, BellSouth informed the Commission that the merger between AT&T Inc. and BellSouth Corporation closed on December 29, 2006, at which time BellSouth Corporation became a wholly-owned, first-tier subsidiary of AT&T Inc. BellSouth noted that, as a result of the merger, it would adopt the AT&T brand name for its products and services.

companies. AT&T maintained that its rapidly declining local directory assistance call volume confirms that many of its customers have migrated to these services. AT&T noted that the number of local directory assistance calls placed to AT&T's Local Directory Assistance Service, including both free allowance calls and paid for calls, has declined by over 74% in the past five years. AT&T explained that its local exchange customers are making fewer calls to AT&T's Local Directory Assistance Service when they incur a charge, and AT&T has also seen a similar drop (68%) in the number of free 411 calls placed during the same timeframe.

AT&T further noted that, in addition to this substantial decline in the total number of local directory assistance calls, AT&T has seen a dramatic plunge in the number of customers who continue to use its 411 service. AT&T stated that between July 2001 and July 2006, the number of access lines that called AT&T's Local 411 service one or more times dropped by 64%.

AT&T asserted that, clearly, some of the drop-off in AT&T's local directory assistance usage can be attributed to CLPs, who now serve many of AT&T's former local exchange customers. AT&T stated that, during the study period between July 2001 and July 2006, AT&T's access lines dropped by about 28% due to local exchange competition. AT&T noted that many CLPs provide their own directory assistance service and that some choose to use competitive wholesale companies to provide their 411 service. AT&T maintained that these competitive wholesale companies include INFONXX, Excell, Metro One, Sprint, and others. AT&T observed that Excell provides enhanced directory assistance services, including movie listings, stock quotes, and more for Vonage customers. AT&T further noted that INFONXX has one of its six call centers located in North Carolina, and that it is the largest independent directory assistance supplier in the world, handling 500 million directory assistance calls per year.

However, AT&T maintained that, with local directory assistance calls declining at a substantially higher rate than access lines, it is also clear that many customers who have remained with AT&T for local exchange service are electing to use alternative directory assistance services.

AT&T argued that consumers and businesses are shifting directory assistance use to mobile devices. AT&T explained that with over 5.7 million wireless subscribers in North Carolina as of December 2005, and with subscribers continuing to grow at an annual rate of 12%, wireless users have played a strong role in pushing the evolution of directory assistance services beyond the traditional 411 service that consumers have used from their residence, business, or a public pay station. AT&T maintained that, as more and more consumers continue to shift their communications needs to wireless devices, the need for directory assistance services has grown because mobile consumers do not have access to published white or yellow page directories that they would normally have at home. AT&T noted that a survey conducted by Harris Interactive between March 31 and June 7, 2006, shows that half of adults who currently use directory assistance say they use it most often in mobile situations. AT&T stated that nearly two-thirds (63%) of adults between the ages of 18 to 28 use directory assistance most often when driving or away from home.

AT&T further asserted that most wireless users have access to several alternative forms of directory assistance. AT&T stated that the more traditional form, by dialing 411, operates in a similar manner to AT&T's landline version except that, in order to compensate for a higher rate (typically, wireless directory assistance runs between $1.40 and $1.80 with no allowances), many wireless carriers also provide value-added services when their customers use this service. AT&T noted that Sprint, Cingular, Verizon, and other cell phone companies offer customers value-added services that typically include such features as business searches by category, movie listings, driving directions, etc., in addition to regular directory listing service.

AT&T observed that cell phones with text messaging capability also have access to SMS that allows users to obtain short information streams, including business addresses and telephone numbers, by merely sending a text message with the name of the company and city to one of several companies, including Google, AskMeNow, and Interexchange Corporation. AT&T explained that, typically within a few seconds, a text message is sent back to the wireless user with the company address and telephone number. AT&T asserted that most of these services are free as long as the user has free text messaging with their wireless carrier. AT&T noted that, if the user pays for text messaging, there is typically a very nominal fee per kilobit of data used. AT&T further observed that SMS also provides additional information such as movie times, sports scores, directions, weather information, stock quotes, and other useful data.

AT&T argued that directory assistance companies offer free/low-cost options to wireline/wireless users. AT&T noted that several companies that specialize in providing directory assistance services have emerged over the past year offering free or extremely low-cost directory alternatives for wireline and wireless users. AT&T explained that Jingle Networks began offering its 1-800-FREE411 service in September 2005 whereby callers receive free directory assistance if they are willing to listen to a short advertisement before receiving the requested telephone number. AT&T observed that businesses that advertise with Jingle Networks benefit since they only pay for advertising when customers select an option to hear more about an advertised offer during a 1-800-FREE411 call. AT&T maintained that Jingle Networks has processed 72 million calls since its introduction and daily call volume is now exceeding 500,000. AT&T also pointed out that a competitor of Jingle Networks, 1-800-411-SAVE, offers a similar service at no charge. AT&T stated that while wireline users can obviously benefit by having free 411 service, cell phone users can also benefit from using these services by only having to pay for airtime from their wireless carriers as compared to the $1.40 to $1.80 fee per call typically charged by cell phone companies for their 411 service. AT&T maintained that, if consumers and businesses want to avoid advertisements, they can use 1-877-Easy411, which charges about $0.65 per call, including call completion. AT&T noted that, in order to use 1-877-Easy411, consumers must register at the company's website and must provide a credit card for billing purposes.

AT&T further asserted that consumers and businesses who have access to the Internet through their computer or a wireless device (including blackberry devices and many cell phones) have no reason to use AT&T's Directory Assistance Service since they have numerous white and yellow page search engines to choose from in order to obtain residential and business telephone numbers. AT&T argued that the vast majority of these search engines also provide added benefits that include, among other features, mapping capabilities. AT&T stated that Internet directory search engines are free and include GoogleMaps, Any Who (AT&T), Addresses.com, AT&T White and Yellow Pages online, AOL Whitepages, InfoSpace, Qwest Dex, Smartpages, The Ultimates, Verizon Superpages, Verizon Big Book, WebCrawler, WhoWhere, World Pages, Yahoo People search, and many others. AT&T maintained that, in addition to allowing users to search for names of people or businesses, some of these also allow alternative searches by category and reverse searches by telephone number.

Next, AT&T asserted that its Directory Assistance average rate is below the market rate. AT&T commented that, in North Carolina, AT&T currently offers local directory assistance at a rate of $0.97 per call and allows four free calls per month. AT&T explained that, based on June 2006 local directory assistance call volumes, the average rate paid per call was actually $0.26 when free call allowances are taken into account. AT&T contended that its average rate is substantially lower than the rates charged by the majority, if not all, of its local exchange competitors. In supporting its argument, AT&T provided the following sample of rates charged by CLPs per call for directory assistance:

Company	Rate	Allowances
Time Warner Digital Phone	$0.99	0
MCI Neighborhood	$0.95	0
Vonage	$0.99	0
Access Integrated	$1.25	0
MyPhoneCo	$0.75	0
CoVista	$0.95	0

AT&T also noted that five of the largest wireless companies, Sprint, Verizon, Cingular, Alltel, and Suncom, all charge $1.40 or more per call for directory assistance, with no free call allowances, as shown below:

Company	Rate	Allowances
Sprint	$1.40	0
Verizon	$1.49	0
Cingular	$1.79	0
Alltel	$1.50	0
Suncom	$1.50	0

In addition, AT&T maintained that its average rate in North Carolina for Local Directory Assistance is, by far, the lowest rate provided throughout its nine-state region. AT&T noted that only two other states have any free local call allowances, and both of those states, Tennessee and Louisiana, only have one allowance. AT&T also asserted that customers in North Carolina also have a significantly larger area where Local Directory Assistance rates apply (versus higher National directory assistance rates) than other AT&T states due to the significant Expanded Local Calling Area arrangements in effect. AT&T provided the following information on rates in AT&T's southeastern states:

State	Rate	Allowance	Average Rate
North Carolina	$0.97	4	$0.26
Florida	$1.25	0	$1.25
Georgia	$1.35	0	$1.35
South Carolina	$1.35	0	$1.35
Tennessee	$1.14	1	$0.78
Alabama	$0.95	0	$0.95
Kentucky	$1.35	0	$1.35
Mississippi	$1.20	0	$1.20
Louisiana	$1.35	1 (Res only)	$0.91

AT&T argued that customers in AT&T's serving area of North Carolina are using numerous wireline, wireless, and Internet local directory assistance alternatives and, with a 74% drop in call volume over the past five years, AT&T no longer has a dominate share of this market. Further, AT&T asserted that, given the current status of competition in the directory assistance marketplace and the choices available to consumers, the Commission should have no concerns about either the price of directory assistance or the number of free allowances that the Company may offer. However, AT&T stated that, since the Commission has expressed concerns in the past about reductions in directory assistance call allowances, it is proposing a gradual transition plan in order to achieve market parity. AT&T proposed the elimination of one free call allowance in the current Plan Year and the elimination of one additional allowance in each of the subsequent Plan Years. AT&T also requested that the Commission allow it to move headroom from the Moderate Flexibility Services Category to the High Flexibility Services Category to offset the revenue impact of reducing these allowances. AT&T noted that the Commission and the Public Staff have approved prior requests from the Company to shift headroom between price regulation service categories or "baskets". AT&T maintained that, as specified in the current tariff, AT&T will continue to provide free 411 service for customers with physical or visual handicaps.

AT&T finally noted that, as required by its price regulation plan, it is prepared to notify customers 14 days in advance of this rate change upon approval of AT&T's Request by the Commission.

INITIAL COMMENTS

<u>Embarq</u> stated in its comments that it generally agrees with AT&T's proposal to eliminate free directory assistance calling and the price regulation plan adjustments associated with this proposal. Embarq noted that, like AT&T, it has experienced a steady decline in the use of its local directory assistance service. Embarq maintained that, as AT&T observed, this decline has resulted from consumers using alternatives to the service. Embarq asserted that these alternatives include the directory assistance service of wireless providers and the many sources of directory assistance that can be accessed via the Internet. Embarq further asserted that it shares AT&T's concern that local exchange carrier prices for local directory assistance in North Carolina are below the prices charged by other providers. Embarq maintained that several of the largest wireless providers, for example, charge local directory assistance rates that are higher than Embarq's rates, and these wireless providers do not offer any free calls for such services.

Embarq commented that, while it agrees with AT&T that free calls to directory assistance should be eliminated, it asks the Commission not to impose on other local exchange carriers AT&T's schedule for eliminating the free calls. Embarq asserted that doing so could discourage the development of enhanced directory assistance services. Specifically, Embarq explained, it is currently considering the development of an enhanced directory assistance service to differentiate its product from that of competitors. Embarq remarked that its enhanced directory assistance service will likely be more costly to provide than its current directory assistance service. Embarq asserted that phasing out free directory assistance calls over four years, as AT&T is proposing, would discourage Embarq's introduction of an enhanced directory assistance service because Embarq would not have the opportunity to more quickly begin recovering the higher costs of the enhanced service.

Embarq maintained that, if the Commission agrees with AT&T's proposal, Embarq sees no reason why AT&T's proposal should be imposed upon Embarq or other local exchange carriers attempting to differentiate services in a competitive market. Embarq noted that a company's proposal for enhanced local directory assistance service should be considered on its own merits.

The Public Staff acknowledged that the competitive landscape for local directory assistance has changed and continues to change and that customers have a variety of ways, through wireline and wireless services and the Internet, to obtain directory assistance. The Public Staff agreed that this increased competition, coupled with a recent price increase for AT&T's offering, has had a negative impact on customer use of AT&T's local directory assistance. The Public Staff further agreed that it has supported prior requests from AT&T to shift specific amounts of headroom between price regulation service categories.

The Public Staff explained that, to assist it in its evaluation of AT&T's Request, the Public Staff requested information from AT&T regarding the average number of customers making local directory assistance calls by number of calls per month. The Public Staff noted that, in response, AT&T provided data for the month of July 2006 that showed that 86% of the customers who accessed local directory assistance did so four or fewer times and 80% accessed local directory assistance three or fewer times.

The Public Staff asserted that reducing the number of free call allowance from four to three calls is reasonable and will continue to meet the needs of a majority of customers who utilize this service from AT&T, as shown by the information provided by AT&T concerning current usage of this service. The Public Staff, however, stated that it does oppose otherwise reducing and eventually eliminating free local directory assistance calls. The Public Staff argued that a limited number of calls are necessary because some customers do not have access to or know about the alternatives to AT&T's service and because some telephone numbers sought by customers are not in the current local directory since they are nonlisted or were added to the network after the directory was published.

In addition, the Public Staff argued that, because the effective date of AT&T's current Price Regulation Plan is May 18, if the Commission approved AT&T's request, AT&T would be able to further reduce the free call allowance in three or four months. The Public Staff opined that, if the Commission permits AT&T to reduce the free call allowance from four to three, the Commission should not consider any further reduction until at least 12 months from the effective date of the first reduction. The Public Staff maintained that this would allow adequate time for the Commission and the Public Staff to evaluate public reaction to the change and determine if further reductions in the free call allowance would be in the public interest.

The Public Staff maintained that, with respect to AT&T's request for headroom flexibility, the Public Staff is not opposed to the concept of moving headroom between price regulation service categories under these circumstances and in the manner requested. However, the Public Staff asserted that more information is needed concerning the amount of headroom AT&T proposes to shift before the Public Staff is able to respond. The Public Staff opined that, if the Commission approves the elimination of one call allowance, the Commission should require AT&T to file documentation on the revenue effect of the reduction before the Commission determines whether a shift in headroom is appropriate. The Public Staff noted that, once AT&T files adequate supporting documentation, the Public Staff will review the filing and make recommendations on the specific revenue effect at a Regular Commission Staff Conference.

Verizon stated in its comments that, like AT&T, it has witnessed a noticeable increase in competition in the North Carolina directory assistance market, and thus supports AT&T's Request.

Verizon noted that a substantial and increasing array of competitors is now offering North Carolina residents a multitude of directory assistance service options. Verizon maintained that it, like AT&T, has experienced a surge in the amount and types of competitors and substitutes for its traditional directory assistance services, among them wireline CLPs, wireless carriers, free telephonic directory assistance providers, and Internet-based services. Verizon stated that, given the current state of competition in North Carolina's directory assistance market and the choices available to consumers, AT&T submits that "the Commission should have no concerns about either the price of directory assistance or the number of free allowances that the Company may offer." Verizon stated that it agrees and supports AT&T's Request. Verizon argued that, given the competitive nature of directory assistance, rather than slowly reducing the size of the free call allowance, the Commission should declare the services competitive, place them in the Total Pricing Flexibility Services category for Companies under price regulation plans, allow companies to price directory assistance according to the market, and remove the free call allowance altogether.

Verizon further maintained that there are a significant number of CLPs competing fiercely for the directory assistance services of traditional wireline providers in North Carolina. Verizon noted that most of these CLPs either self-provision local directory assistance services or obtain directory assistance services on a wholesale basis from a competitive provider. Verizon asserted that, as AT&T has demonstrated, the decline in local directory assistance usage is only partially attributable to the wireline carriers' loss of customers to CLPs.

Verizon opined that AT&T is similarly correct that consumers and businesses are shifting directory assistance usage to wireless devices. Verizon noted that wireless carriers, such as

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Cingular, Sprint/Nextel, Verizon Wireless, and other wireless companies serving North Carolina, all compete with providers of traditional directory assistance service. Verizon noted that these carriers provide directory assistance services, most often with call-connect services that directly connect the caller to the number sought from the directory assistance operator. Verizon observed that wireline customers with a wireless phone, therefore, may choose to use their wireless phones for directory assistance, further diminishing the amount of traditional 411 directory assistance calls.

Verizon noted that a new breed of competitors has begun to offer free telephonic directory assistance services in North Carolina. Verizon asserted that, as AT&T has noted, Jingle Networks, Inc., recently launched a service that allows residential and business customers to make free directory assistance calls from any wireline or wireless telephone by simply dialing 1-800-FREE411.

Verizon maintained that Internet-based alternatives accessed through wireline and wireless enabled personal computers, wireless handsets, and personal data assistants are putting substantial and increasing pressure on traditional directory assistance services. Verizon noted that these Internet-based providers compete with traditional directory assistance services by allowing business and residential customers to obtain directory assistance information from a host of World Wide Web sites that are accessed for free via an Internet connection using telephone, cable, or satellite. Verizon commented that these websites provide access to a multitude of free "online" directory assistance database directories. Verizon observed that competitive pressure on traditional directory assistance services from Internet-based directory assistance services has increased as Internet usage and capabilities have increased. Verizon asserted that the high and increasing penetration of Internet access is noteworthy because a 2004 study by the Pew Center for the Internet and the Public Interest found that 54% of Internet users employed the Internet to search for telephone numbers or addresses. Moreover, Verizon noted, a recent report predicted that online directory assistance website visits would increase from 660 million per year in 1999 to over 5 billion visits per year in 2006.

Verizon remarked that it has also experienced increasing competitive pressure from Voice Over Internet Protocol (VoIP) providers, electronic media directory assistance service providers, Alternative Directory Assistance Providers (ADAPs), cable companies, and print directories. Verizon maintained that scores of VoIP providers have entered the directory assistance market in North Carolina. Verizon stated that Vonage, for example, touts the features of its "Enhanced 411" service as follows:

> With Vonage Enhanced Directory Assistance you get listings and information you need across a wide range of categories – fast. It's just 99 cents per 411 call anywhere in the US, Canada and Puerto Rico. (Our operators speak both English and Spanish.) (Each 411 call you make from a Vonage phone gets you up to two listings.)

Verizon further commented that examples of other VoIP providers offering residential and business directory assistance services include Via Talk and Sun Rocket, among others.

Verizon noted that electronic media directory assistance service providers similarly compete with providers of traditional directory assistance services. Verizon maintained that companies such as American Business Information and Info USA provide white and yellow page phonebooks on CD-ROM. Verizon also stated that, in addition to such listings, these products also provide reverse search and automatic telephone connection to the requested listing, and provide additional advanced features not available from providers of traditional directory assistance services. Verizon asserted that these products have been heavily marketed as cost-effective and widely used alternatives to telephonic directory assistance.

Verizon contended that, in addition, ADAPs offer a standalone suite of local and national directory assistance services to retail and wholesale customers. Verizon stated that, for example, INFONXX offers 411 Plus, which according to INFONXX, cuts corporate costs by providing employees with the highest-quality directory assistance services at a fraction of the cost charged by local telephone companies. Verizon also noted that the INFONXX plan includes enhanced features such as information on traffic and transportation, movie listings and dining information, sports scores, stock quotes, and text direct and SMS directory assistance, which allows a requested name, phone number, and address to be sent to a mobile device. Verizon maintained that, as another example, DAAmerica offers companies, organizations, and government entities nationwide directory assistance in monthly agreements with no set-up or maintenance charges. Verizon explained that DAAmerica programs the customer's Private Branch Exchange (PBX) to dial a toll-free directory assistance number whenever an employee calls "411" or "NPA-555-1212". Verizon also asserted that when DAAmerica compares its plan to those offered by Verizon, AT&T, and Sprint, DAAmerica claims that it "will instantly reduce these rates by 50 percent or more".

Further, Verizon commented that cable companies are also vying for market share. Verizon noted that cable companies are aggressively expanding their cable telephony and broadband offerings in North Carolina.

Verizon finally noted that well-established paper white and yellow-page telephone directories are provided free of charge throughout North Carolina to business and residence customers, and are valued and utilized by end users. Verizon maintained that customers can use telephone directories to get the same information as directory assistance and at no charge.

Verizon concluded that, given the wide array and growing popularity of competitive alternatives to traditional local directory assistance services, Verizon supports AT&T's Request. Verizon noted that the Commission should take the further actions of declaring directory assistance services competitive, placing them in the Total Pricing Flexibility Services category for companies under price regulation plans, allowing companies to price the directory assistance services according to the market, and removing the free call allowance altogether.

REPLY COMMENTS

<u>AT&T</u> noted in its reply comments that Verizon agreed with AT&T's assessment of the competitive landscape and supported AT&T's request to reduce free call allowances. However, AT&T maintained, Verizon encouraged the Commission to act more aggressively by declaring

local directory assistance competitive, placing it in the Total Pricing Flexibility Services category for companies under price regulation, and removing free call allowances all together. AT&T further noted that, in addition to concurring in the evidence presented by AT&T, and acknowledging that it, too, has experienced a surge in the amount and types of competitors offering substitutes for traditional directory assistance service, Verizon presented additional competitive evidence. AT&T asserted that Verizon cited a 2004 study by the Pew Center for the Internet and the Public Interest that found that 54% of Internet users employed the Internet to search for telephone numbers or addresses. AT&T further maintained that Verizon also indicated that it has also experienced increasing directory assistance competitive pressure from VoIP providers, electronic media directory assistance service providers, Alternative Directory Providers, cable companies, and print directories.

AT&T further noted that Embarq also generally agreed with AT&T's Request, acknowledging that it also had witnessed a steady decline in the use of local directory assistance service due to competition, but it encouraged the Commission to not impose on other local exchange carriers AT&T's schedule for eliminating free call allowances. AT&T maintained that Embarq had noted that doing so would discourage it from introducing enhanced directory assistance services since, under such a schedule, it would not have the opportunity to more quickly recover the higher costs of delivering enhanced services.

AT&T further noted that the Public Staff had acknowledged that the competitive landscape for local directory assistance had changed and continues to change and that customers have a variety of ways, through wireline and wireless services and the Internet, to obtain directory assistance. In addition, AT&T observed that the Public Staff agreed that this increased competition, coupled with a recent increase in the price for AT&T's offering, has had a negative impact on customer use of AT&T's local directory assistance. AT&T maintained that the Public Staff also pointed out that, based on July 2006 data provided by AT&T, 86% of the customers who accessed local directory assistance did so four or fewer times while 80% did so three or fewer times. AT&T also noted that the Public Staff had stated that reducing the number of allowable free calls from four to three was reasonable; however, the Public Staff opposed otherwise reducing and eventually eliminating free local directory assistance calls based on two factors:

1. A limited number of calls are necessary because some customers do not have access to or know about the alternatives to AT&T's service; and

2. Some telephone numbers sought by customers are not in the current local directory because they are nonlisted or were added to the network after the directory was published.

AT&T asserted that the Public Staff provided no empirical support for its view that the number of free call allowances should only be reduced by one other than references to July 2006 local directory assistance data that it requested from AT&T. AT&T argued that this usage data, however, is only relevant to the universe of customers who continue to use AT&T's local directory assistance. AT&T maintained that, with only about 14% of AT&T's access lines in North Carolina using this service, local directory assistance has clearly become a discretionary, highly competitive service. AT&T opined that it is also worth noting that, of this small universe of customers who continue to use AT&T local directory assistance service, 70% did so two or fewer times and 49% did so only one time.

AT&T contended that the Public Staff's argument that some customers do not have access to or know about competitive alternatives is only marginally relevant because "some" can represent a very small universe of customers. AT&T maintained that it does not have to prove that all customers are knowledgeable about competitive alternatives to justify its request. AT&T opined that it should only be required to show, as it has done, that these alternatives are available to a significant portion of its serving area and that customers are actively using these services. AT&T asserted that the competitive directory assistance services and alternatives that AT&T and Verizon address in their comments include:

- A plethora of Internet directory search engines including Anywho.com, Yellowpages.com, and others;
- Free and pay-per-use options offered by alternative directory assistance companies that may be accessed via wireline and wireless phones;
- Pay-per-use options offered by numerous wireless companies, CLPs, VoIP providers, and cable companies; and
- Published and electronic media (CD-ROM) directories.

AT&T argued that, with over 93% of households having telephone service in North Carolina, with over 5.7 million wireless telephone subscribers in North Carolina (11th highest in the nation) and with North Carolina also having the 11th highest number of high-speed Internet access lines in the nation, it is clear that the vast majority of consumers and businesses in North Carolina do have access, in some form, to several of these alternatives and that they are most likely aware of multiple alternatives since these competitive options are available through numerous methods of communication (i.e., telephone, Internet, wireless, published). AT&T opined that alternate directory assistance companies that provide their service through toll-free numbers both on a free or pay-per-use basis must be doing an effective job of advertising the availability of their service if Jingle Networks (1-800-FREE411), on its own, has been able to handle over 72 million directory inquiries since starting its business in September 2005 and is now averaging over 500,000 calls per day.

AT&T maintained that, likewise, Internet options are also widely available to the general public according to Pew Internet & American Life Project Surveys (Pew) and ComScope (a leader in measuring digital age usage). AT&T noted that Pew estimates that, as of the beginning of 2006, about 73% of all American adults go online. AT&T stated that Verizon's comments noted that a Pew study in 2004 showed that 53% of these Internet users employed the Internet to search for telephone numbers or addresses. AT&T argued that a more recent study by ComScope (covered in a September 2006 press release) reported that local searches, which include searches done by consumers on the local or directory (yellow pages) sections of leading search sites, totaled 849 million nationwide in July 2006 and that 63% of all Internet users in the United States (during the same study period) performed a local search. AT&T maintained that, providing further support that people are aware of and are actively using directory search sites, AT&T's YellowPages.com, one of many directory search websites, provides exposure to over 100 million consumer searches per month through its total network. AT&T opined that individuals are using the Internet to find telephone numbers, addresses, directions, and other information about businesses and people in their community which, prior to the Internet, they could only obtain through published directories and local directory assistance service.

Further, AT&T commented that the Public Staff's final point, that all numbers may not be in the current directory, should not require continuation of the status quo in a highly competitive directory assistance marketplace. AT&T asserted that it should not be required to offer free allowances when competitive services do not have comparable requirements. Additionally, AT&T argued, consumers and businesses have access to a number of free sources for directory listings that are continually updated including Internet directory search engines offered by AT&T and other companies as well as through alternative free directory assistance services available via both wireline and wireless phones.

AT&T asserted that it has made a very fair proposal to the Commission to gradually phase out free call allowances. AT&T opined that the directory assistance market is sufficiently competitive today to warrant total elimination of all allowances with no time delay. As such, AT&T requested that the Commission approve its original request without revisions.

DISCUSSION AND CONCLUSIONS

The Commission notes that it rejected AT&T's request in its most recent price regulation plan revision proceeding to include local directory assistance service in the Total Pricing Flexibility Basket. Specifically, the Commission ruled, in part, in its March 24, 2005 *Notice of Decision and Order* that:

> 1. The services initially included in each of the three price plan baskets will generally be as proposed by BellSouth in its Final Proposed Price Plan Revisions filed on March 2, 2005 (Attachment A, Exhibits 1 through 3), <u>except that local directory assistance service will be included in the High Pricing Flexibility Basket rather than the Total Pricing Flexibility Basket</u>. [Emphasis added.]
>
> 2. Local directory assistance service will continue to be provided as a tariffed service in the High Pricing Flexibility Basket and no free call allowances will be eliminated except upon express approval from the Commission.

AT&T's most recent price regulation plan reflecting this decision was effective as of May 18, 2005.

The Commission agrees with AT&T, Embarq, the Public Staff, and Verizon that there are an increasing number of alternatives available to customers seeking local directory assistance service. However, the Commission does not believe that enough persuasive support exists to determine that local directory assistance is sufficiently competitive today. After reviewing the comments filed in this regard, the Commission agrees with and supports the Public Staff's proposal of allowing AT&T to reduce the number of free call allowances by one (from four to three) during the upcoming price regulation plan year beginning in May 2007. The Commission believes that this decision should be acceptable to AT&T, at this point in time, since it provides for a reduction in call allowances and technically grants AT&T's Request for year one, while allowing the Commission flexibility and adequate time to evaluate the public reaction to the reduction and determine if further reductions in the free call allowances would be in the public interest.

The Commission finds persuasive the Public Staff's opinion that a limited number of calls are necessary because some customers do not have access to or know about the alternatives to AT&T's service, and some telephone numbers sought by customers are not in the current local directory because they are nonlisted or were added to the network after the directory was published. The Federal Communications Commission's (FCC's) most recent Report on the status of the broadband market, entitled "High-Speed Services for Internet Access: Status as of June 30, 2006", shows in Table 10 that North Carolina had 1,601,938 high-speed lines as of June 30, 2006, which puts North Carolina as 13th in the nation. According to the Public Staff's Telephone Development Report, incumbent local exchange companies (ILECs) had 3,820,513 total access lines in service for local switched access service at the end of June 2006. This number does not reflect any CLP or VoIP access lines in the State. The Commission believes that these numbers show that not all customers have access to the Internet to search for telephone numbers. In addition, while wireless carriers provide another source of directory assistance information, as AT&T noted in its Request, the five largest wireless carriers charge $1.40 or more for each local directory assistance call with no free call allowances. And not all customers have access to wireless directory assistance. Further, the Commission believes that it is reasonable to assume that not all customers have knowledge about alternatives to traditional 411 service or, if they do, that they may not find those alternatives to be acceptable substitutes for traditional 411 service. For example, customers using 1-800-FREE411 must find it acceptable to dial eight additional digits and listen to advertisements before receiving the desired telephone number for the service to be a substitute for traditional 411.

With respect to AT&T's request to be allowed to move headroom in its Plan from the Moderate Flexibility Services Basket to the High Flexibility Services Basket to offset the revenue impact of reducing the allowances, the Commission finds the Public Staff's recommendation on this issue reasonable. Therefore, the Commission finds it appropriate to require AT&T to file documentation on the revenue effect of the reduction in allowances from four to three before the Commission will determine if the shift in headroom is appropriate. The Public Staff is requested to review the documentation once it is filed and make recommendations on the specific revenue effect to the Commission at a Regular Commission Staff Conference.

IT IS, THEREFORE, ORDERED as follows:

1. That AT&T may reduce its free directory assistance call allowances from four calls a month to three calls a month effective at the beginning of the upcoming price regulation Plan year;

2. That this approved reduction applies solely to AT&T and not to any other carriers;

3. That AT&T may file another Request with the Commission in approximately 12 months to further reduce the free directory assistance call allowances;

4. That AT&T shall file supporting documentation on the revenue effect of the approved reduction from four calls to three free calls; and

5. That the Public Staff shall review the documentation once it is filed by AT&T and make recommendations on the specific revenue effect to the Commission at a Regular Commission Staff Conference.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of March, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp031407.01

Commissioner Sam J. Ervin, IV, concurs in the result.
Commissioner James Y. Kerr, II dissents.
Commissioner Edward S. Finley, Jr. did not participate.

DOCKET NO. P-55, SUB 1013

Commissioner Sam J. Ervin, IV, concurring in the result:

Although I concur in the result reached by the Commission with respect to AT&T's request for gradual elimination of the existing free directory assistance call allowances, I write separately to indicate my concern about the absence of a standard under which this and similar proposals to eliminate or reduce the number of free directory assistance call allowances should be evaluated and my concern about the reasoning on which the Commission has based its decision in this instance. As a result, I concur in the result reached by the Commission without adopting the reasoning under which the Commission reached its decision.

At the time that I examined AT&T's filing and the related comments, I struggled with attempting to identify the standard against which the Company's request should be evaluated. Should, for example, the outcome hinge solely on an analysis of competitive conditions in the market for local directory assistance service? Or should the outcome, at least in part, be affected by public interest considerations separate and apart from competitive conditions? The parties do not explicitly discuss this issue in their filings, as best I have been able to determine, and the Commission does not definitively adopt a standard for evaluating such requests in its Order. I believe that this is an important issue and would like for it to be resolved so as to establish an orderly process for dealing with such requests as they arise. I trust that the parties will clearly address the standard against which issues of this nature should be evaluated and that the Commission will clearly decide this issue at such time as AT&T renews its request for the complete elimination of or a reduction in the number of free directory assistance call allowances established in this Order.

At this point, I have not reached a personal decision with respect to the "standard" issue and will be open to persuasion in future proceedings. I am confident that the Commission will inevitably have to address this issue in the future and hope that we will resolve it one way or another the next time that AT&T or any other price-regulated local exchange carrier seeks an alteration in the number of free local directory assistance calls which it is required to provide to its local exchange customers. Until we have addressed and resolved the "standard" issue, I think that the Commission and the parties will continue to struggle to resolve issues of the nature raised by AT&T's filings in a consistent and predictable manner.

Furthermore, an examination of the Commission's Order reveals an apparent inconsistency in the analysis that is employed to support the Commission's decision. At the beginning of its analysis, the Commission agrees "that there are an increasing number of alternatives available to customers seeking local directory assistance service." At that point, one could conclude that the Commission believes that evidence of competition for local directory assistance service would, at some level, suffice to justify granting the relief that AT&T has requested in this proceeding. Having said that, however, the Commission further expresses its belief "that [not] enough persuasive support exists to determine that local directory assistance is sufficiently competitive today." Such language would tend to suggest that AT&T has failed to make an adequate showing that the market for local directory assistance is sufficiently competitive and that, were AT&T to make such a showing, the relief the Company has requested would be granted. On the other hand, the Commission expresses agreement with "the Public Staff's opinion that a limited number of calls are necessary because some customers do not have access to or know about the alternatives to AT&T's service, and because some telephone numbers sought by customers are not in the local directory because they are nonlisted or were added to the network after the directory was published." As a result of the fact that there will always be numbers that are not listed in local directories due to changes in the composition of the local population base, this statement would tend to suggest that the Commission believes that some number of free local directory assistance calls is an inherent part of the provision of local exchange service and should be required in perpetuity. In view of this apparent inconsistency, I am unable to join the Commission's Order without qualification.

I am not, however, convinced that my concern over the Commission's failure to address and resolve the "standard" issue or my concern about the analytical component of the Commission's Order requires me to dissent from the Commission's ultimate decision. At this point, AT&T has only requested to eliminate one free call allowance in the near term, no party to this proceeding has opposed that request, and the comments disclose the existence of a number of competitive alternatives to local exchange company directory assistance service. Although adoption of AT&T's exact proposal would result in the adoption of a definitive schedule for the phased elimination of the remaining free local directory assistance call allowances and would allow the elimination of a second allowance within a relatively short period of time, the fact that the "standard" issue remains open and the fact that approval of AT&T's proposal would require the Commission to make an immediate decision about what should happen in the future causes me to conclude that the majority has reached the correct result despite my concerns about the lack of any resolution of the "standard" issue and the inconsistency inherent in the analysis adopted in the Commission's Order. As a result, I concur in the result without necessarily agreeing with all of the language in the analytical portion of the Commission's Order.

/s/ Commissioner Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

Docket P-55, Sub 1013

Commissioner James Y. Kerr, II, dissenting:

I am dissenting from the Majority's decision in this docket not because I necessarily believe that there should be *no* free directory assistance calls available to subscribers but because I believe we lack at this time a reasonably objective standard to judge such applications for reduction. We also lack a sufficient record to determine whether a given number of free directory assistance calls should be allowed. Accordingly, the Majority's decision amounts to an arbitrary conclusion that, for now, says "this is right because we say so."

It is not surprising that we lack a standard for decision-making in this docket because, at present, no reasonably objective standard for this purpose has been plainly articulated. The telephone companies, when they come before us, do not know what exactly it is they need to prove to us before their petition will be approved. This is not fair. There should be more predictability in the process—something more than "come back to us in about a year." The Commission should have attempted to provide more guidance as to what needs to be demonstrated and what needs to change to allow for a different result.

The Majority attempts to rely on three main rationales for supporting its result. First, the Majority noted that the Commission had recently rejected AT&T's request for a reduction in free directory assistance calls in its March 24, 2005, *Notice of Decision and Order*, concerning the latest price plan revision.[1] The second rationale was that a limited number of free directory assistance calls are necessary because some customers do not have access or know about alternatives to AT&T's service, and current local directories are not completely current. Third, while acknowledging that competitive alternatives exist and are increasingly available, the Majority stated that there was not "enough persuasive support to determine that local directory assistance is sufficiently competitive today." Nevertheless, the Majority followed the Public Staff's recommendation and allowed for the reduction of one free call and the possibility of a revision of headroom from the Moderate Flexibility Services Basket to the High Flexibility Services Basket.

It is not clear to me what precisely has changed since 2005 to justify the reduction of one free call but not two or more calls—or, on the other hand, any calls at all. This renders highly

[1] The Commission did, however, provide that local directory assistance service would be included in the High Pricing Flexibility Basket rather than the Total Price Flexibility Basket.

problematic the Majority's invitation for AT&T to reapply in a year. AT&T still will not know what it needs to prove. It is uncontroverted that of the other states in AT&T's region all but two do not provide for a free call allowance, and those that do provide for only one. What is the difference, if any, between North Carolina and those other states? This is left unexplained. The more general question is what is the evidence that AT&T or other similar applicants need to bring forth to the Commission so the answer will not again be "No"; or, if the answer is still "No," why this is so.

My own view is that there should be universal agreement that a reasonably objective standard would relate to the existence of effective competition in access to directory assistance information. As AT&T and other intervenors pointed out, they believe that effective competition with incumbent local exchange carriers exists in many forms—from competing local providers, from VoIP, from cellular services, and from the internet. But it is also true, as the old saying goes, that the "devil's in the details." The details that need to be supplied are more precise measurements of the nature and degree of competition relevant to this service, so it can be determined whether the competition is truly effective competition. Perhaps a certain degree of subjectivity in decision-making is inevitable, but the decision-making process can certainly be improved through the application of more objective standards and the recognition of clear competitive trends.

Most simply put, this particular controversy has to do with local exchange company subscriber access, directly or indirectly, to directory—i.e., computer—databases. In my view, the most important competitive trend in this area relates to the increased pervasiveness of the internet, especially broadband. AT&T and the intervenors supporting them rightly pointed out the existence of competitive alternatives, including those to be found on the internet. Nevertheless, it is certainly a relevant consideration that not all subscribers, especially those of limited means, have access to the internet; but we have no information in this docket as to how many that might be.[1] Such information could be very useful in determining whether the number free directory assistance calls should be maintained or reduced. I believe that, as internet penetration (especially broadband) increases, the case for the current number of free directory assistance calls will also be reduced. In terms of proof of internet and broadband penetration, I believe that the more specific such information is to the franchise territory of the company concerned, the better and more probative the information is.

Ultimately, of course, it is up to the telephone companies to prove their case before the Commission. But the Commission can improve the process by insisting upon and abiding by reasonably objective standards for decision, while the petitioners and other interested parties can assist by providing specific and up-to-date data regarding the relative criteria.

/s/ Commissioner James Y. Kerr, II
Commissioner James Y. Kerr, II

[1] All subscribers receive published directories for local numbers, but published directories, while helpful, are incomplete almost from the date of publication and, because of the limitations of the medium, are inherently incomplete and cannot be updated before the following year. On the other hand, electronic databases are more capable of being updated closer to real time. The important question is not whether such electronic databases exist but rather the degree to which incumbent local exchange carrier subscribers have direct access to them through personal computers, especially through broadband.

DOCKET NO. P-75, SUB 63
DOCKET NO. P-76, SUB 53
DOCKET NO. P-60, SUB 73

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of Barnardsville Telephone Company, Saluda Mountain Telephone Company, and Service Telephone Company for Approval of a Price Regulation Plan Pursuant to G.S. 62-133.5(a))	ORDER APPROVING PRICE REGULATION PLAN

HEARD: Wednesday, February 7, 2007, at the Barnardsville Family Resource Center, 540 Dillingham Road, Barnardsville, North Carolina

Thursday, February 8, 2007, at the Saluda Community Library, Council Room, 44 W. Main Street, Saluda. North Carolina

Tuesday, March 6, 2007, at the Dempsey B. Herring Courthouse Annex, Hearing Room, 112 W. Smith Street, Whiteville, North Carolina

Wednesday, March 7, 2007, in Commission Hearing Room 2115, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorenzo L. Joyner, Presiding; and Commissioners Sam J. Ervin, IV, and William T. Culpepper, III

APPEARANCES.

FOR THE TDS COMPANIES:

Daniel C. Higgins
Burns, Day & Presnell, P.A.
2626 Glenwood Ave., Suite 560
Raleigh, North Carolina 27608

FOR THE USING AND CONSUMING PUBLIC:

Elizabeth D. Szafran
Public Staff- North Carolina Utilities Commission
4326 Mail Service Center
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BY THE COMMISSION: G.S. 62-133.5(a) provides that "[a]ny local exchange company [LEC], subject to the provisions of G.S. 62-110(f1), that is subject to rate of return regulation pursuant to G.S. 62-133 . . . may elect to have rates, terms and conditions of its services determined pursuant to a form of price regulation, rather than rate of return or other forms of earnings regulation."

Under the form of price regulation authorized by G.S. 62-133.5(a), "the Commission shall, among other things, permit the local exchange company to determine and set its own depreciation rates, to rebalance its rates, and to adjust its prices in the aggregate, or to adjust its prices for various aggregated categories of services, based upon changes in generally accepted indices of prices."

G.S. 62-133.5(a) requires notice and a hearing, allows different forms of price regulation as between different LECs, and requires the Commission to decide price regulation cases within 90 days subject to an extension by the Commission for an additional 90 days, or a total of 180 days from the filing of the Application. The statute requires the Commission to approve price regulation for a LEC upon finding that a proposed plan:

(i) protects the affordability of basic local exchange service, as such service is defined by the Commission;

(ii) reasonably assures the continuation of basic local exchange service that meets reasonable service standards that the Commission may adopt;

(iii) will not unreasonably prejudice any class of telephone customers, including telecommunications companies; and

(iv) is otherwise consistent with the public interest.

Barnardsville Telephone Company, Saluda Mountain Telephone Company and Service Telephone Company (collectively "the TDS Companies") are all currently operating under traditional rate of return regulation as provided for in G.S. 62-133.

On October 30, 2006, the TDS Companies filed with the Commission a Petition for Approval of Price Regulation Plan. In the Petition, the TDS Companies advised the Commission that they sought to implement a price regulation plan substantially identical to the price regulation plans recently approved by the Commission for other local exchange companies. On that same date, the TDS Companies also filed with the Commission a Stipulation and Agreement with the Public Staff in which those parties agreed to a price regulation plan for the TDS Companies (the "Stipulated Plan" or "Plan").

The Stipulated Plan provides for the following:

- Classification of existing services into four new categories of service designated as Moderate Pricing Flexibility, Discretionary Pricing Flexibility, High Pricing Flexibility, and Total Pricing Flexibility.

- Services that would be classified in the Moderate Pricing Flexibility category include business and residential basic local exchange services and switched access charges applicable to interexchange carriers. Prices for these services could be increased by a maximum of 10% in each Plan year, provided that revenues for the category do not increase by more than one and one-half times the rate of inflation.

- Initially, there would be no services that would be classified to the Discretionary Pricing Flexibility category. Prices for services placed into the Discretionary category will be no higher than tariff rates but may be reduced to individual customers, for competitive reasons, below tariff rates at the TDS Companies' discretion.

- Services that would be classified to the High Pricing Flexibility category include operator assisted local calls and optional business and residential calling features. Prices for these services could be increased by a maximum of 20% in each Plan year, provided that revenues for the category do not increase by more than two and one-half times the rate of inflation.

- Services in the Total Pricing Flexibility category include Centrex service. Prices for these services would not be regulated by the Plan.

- Revisions to extended local calling. In conjunction with their implementation of the proposed Plan, the TDS Companies will rebalance certain rates.

  For Barnardsville Telephone Company ("Barnardsville"), the rebalancing proposal calls for a unification of the rates associated with Barnardsville's TDS Plus Plan. The rate for usage based calling throughout the TDS Plus Plan, Calling Areas 1 and 2, will be 4 cents per minute. The monthly rate for optional flat-rate unlimited expanded local calling will be reduced to $7.00. This rate is the same as the rate for calling to Calling Area 1 only. Customers subscribing to Calling Area 1 optional flat-rated plan will be moved to the plan that includes both Calling Areas 1 and 2. Also proposed are rate increases for local directory assistance, directory listings, service connection charges and some optional calling feature services. Barnardsville will freeze rates for two years for any rebalanced rate element initially increased by more than the allowed rate element constraint.

  For Saluda Mountain Telephone Company ("Saluda"), the rebalancing proposal calls for rate reductions to the optional flat-rate unlimited plan and the measured initial per minute rate for Saluda's TDS Plus Plan. In addition to these reductions, rebalancing of the service connection charges and rate increases for local directory assistance, directory listings, and some optional custom calling feature services are proposed. The Plan also proposes to roll Touchtone charges into the basic rate. Customers with Touchtone will not experience an increase. Saluda will freeze rates for two years for any rebalanced rate element initially increased by more than the allowed rate element constraint.

  For Service Telephone Company ("Service"), the rebalancing proposal calls for rate reductions to the flat-rate unlimited plan ($13.20 to $8.50) and the measured per minute rate for the TDS Plus Plan (9 and 7 cents to 3 cents per minute). In addition to these reductions, rebalancing of the service connection charges and rate increases for basic local exchange rates, local directory assistance, directory listings, and some optional custom calling feature sen/ices are being proposed. Service will freeze rates for two years for any rebalanced rate element initially increased by more than the allowed rate element constraint.

- Financial penalties to be paid to customers if the TDS Companies fail to meet service objectives established by the Commission.

On December 13, 2006, the Commission issued its Order Scheduling Hearing and Requiring Public Notice. This Order scheduled public hearings in each of the TDS Companies' service areas with respect to the TDS Companies' Petition Seeking Approval of Price Regulation Plan and the Stipulation and Agreement between the TDS Companies and the Public Staff. That Order scheduled hearings in Barnardsville for February 7, 2007. in Saluda for February 8, 2007, and in Whiteville for March 6, 2007. This Order also set the evidentiary hearing in these dockets for Raleigh on March 7, 2007. The Order required that the TDS Companies publish notice of the hearings in newspapers having general circulation in each of their service areas for two weeks beginning the weeks of January 15 and 22, 2007; that the TDS Companies send the Notice to their customers by means of bill inserts for receipt on or about January 8, 2007; that the TDS Companies prefile direct testimony not later than February 2, 2007; that the Public Staff and any other intervener prefile direct testimony not later than February 23, 2007; that rebuttal testimony be filed not later than February 27, 2007; that petitions to intervene be filed no later than January 29, 2007; and that parties file witness lists, proposed order of witnesses and estimated cross-examination times not later than March 2. 2007.

No interested person petitioned to intervene in these dockets. On February 2, 2007, the TDS Companies filed the direct testimony of witness James C. Meade, Director of Regulatory Affairs. On February 5, 2007, the TDS Companies filed affidavits of publication that public notice had been provided in accordance with the Commission's Procedural Order. On February 23, 2007, the Public Staff filed the direct testimony of witness Charles B. Moye, an Engineer with the Communications Division. Both witnesses supported the Stipulated Plan.

At the February 7, 2007 public hearing in Barnardsville, both parties were present, as well as one member of the public, who chose not to remain for the hearing and did not testify.

At the February 8, 2007 public hearing in Saluda, both parties were present, as well as several members of the public. Those members of the public present included Jane Gado and Gene Dickson.

At the March 6, 2007 public hearing in Whiteville, both parties were present. No member of the public appeared.

At the March 7, 2007, public and evidentiary hearing in Raleigh, no member of the public appeared. TDS witness Meade and Public Staff witness Moye testified without objection.

A Joint Proposed Order was filed by the TDS Companies and the Public Staff on April 16, 2007.

WHEREFORE, based on the foregoing, the evidence adduced at the hearing, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Each of the TDS Companies is a "local exchange company" as the term is defined in G.S. 62-3(16a). The TDS Companies are currently subject to rate of return regulation pursuant to the provisions of G.S. 62-133 and have sought to elect price regulation pursuant to G.S. 62-133.5. Thus, this matter is properly before the Commission for consideration, and the TDS Companies meet all of the requirements for price regulation under G.S. 62-133.5.

2. The Stipulated Plan wilt protect the affordability of basic local exchange service.

3. The Stipulated Plan will reasonably assure the continuation of basic local exchange service that meets reasonable service standards.

4. The Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

5. The Stipulated Plan is otherwise consistent with the public interest.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 1

Finding of Fact and Conclusion of Law No. 1 is supported by the record as a whole and is not contested.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 2-AFFORDABILITY

Finding of Fact and Conclusion of Law No. 2 (and Nos. 3-5 as well) are supported by the testimony and exhibits of TDS witness Meade and Public Staff witness Moye. The Commission has also taken into account the testimony of public witnesses Gado and Dickson concerning the implementation by Saluda of the extended area service ("EAS") proposal approved by the Commission in Docket P-76, Sub 50.

TDS witness Meade testified as to the economic rationale for the TDS Companies' adoption of the Plan; the economic context in which the Plan should be evaluated; the recent changes in competitive landscape for telecommunications services in the United States and North Carolina; and the effects of new technology and increased competitive options. In addition, witness Meade explained why the TDS Companies sought to move to a price plan. Specifically, witness Meade testified that the Stipulated Plan would enable the TDS Companies to more quickly react to competitive pressures and changing customer expectations and demand. The flexibility provided for in the Stipulated Plan would provide immediate as well as long-term benefits to many of the TDS Companies' customers and would allow the TDS Companies to better meet competitive challenges within their territories.

In his direct testimony, witness Meade discussed the detailed provisions of the Stipulated Plan, explained why it is consistent with the requirements of G.S. 62-133.5(a), and stated that it represents a compromise supported by representatives of the using and consuming public and the TDS Companies. Witness Meade stated that the TDS Companies have experienced a net loss of access lines to competition, that such losses continue to date, and that the prospect for future losses through competition is high. Witness Meade testified to significant risk for traditional wireline local telephone companies from competition from wireless and Voice over Internet Protocol ("VoIP") providers.

Public Staff witness Moye also testified that developments have changed the landscape of the telecommunications industry in North Carolina since local competition was authorized by state and federal law. Specifically, witness Moye described these changes as the growth in access line competition from CLPs; the growth in wireless service; the halt and possible permanent reversal of access line growth for incumbent LECs; and the potential for further competition from new technologies. In addition, witness Moye testified that the Stipulated Plan satisfies the criteria of G.S. 62-133.5(a). Like witness Meade, he indicated that the Stipulated Plan is a reasonable compromise between the TDS Companies and the Public Staff. The testimony of witnesses Meade and Moye establishes that, for many services in the TDS Companies' service areas, price constraints imposed by the existence of competitors are current, real and generally effective, aiding the Commission's determination that the Stipulated Plan will result in affordable rates.

In Commission Rule R17-1(a) the Commission has defined basic local exchange service as "[t]he telephone service comprised of an access line, dial tone, the availability of touchtone, and usage provided to the premises of residential customers or business customers within a local exchange area." In the Stipulated Plan, basic local exchange service is included in the Moderate Pricing Flexibility Services category, which allows the TDS Companies greater flexibility to adjust the price of basic local exchange service. Under the Stipulated Plan, aggregate annual price changes for services included in the Moderate Pricing Flexibility Services category are limited to one and one half times the rate of inflation as measured by the annual change in the Gross Domestic Product Price Index ("GDPPI"), minus a productivity offset of zero. The constraint for the High Pricing Flexibility Services category is set at two and one-half times the GDPPI minus the offset.

As witness Moye noted, the rate element constraints are based on a set percentage. Under the Stipulated Plan, the rate element constraint is 10% in the Moderate Pricing Flexibility Service category. In the High Pricing Flexibility Services category the rate element constraint is 20%. The Stipulated Plan also includes a provision under which any rate element in the Moderate Pricing Flexibility Services category may be increased on an annual basis by up to ten percent (10%) or thirty-five cents ($0.35). whichever is greater, if it is priced on a flat-rated monthly basis and up to ten percent (10%) or fifteen cents ($0.15), whichever is greater, if it is priced on a peruse basis. A similar constraint is available for rate elements in the High Pricing Flexibility Services category with the following allowed rate increases: up to twenty percent (20%) or fifty cents ($0.50), whichever is greater, for rate elements priced on a flat-rated monthly basis, and up to twenty percent (20%) or thirty cents ($.30), whichever is greater, for rate elements priced on a per-use basis.

The Commission concludes that the incremental increase in pricing flexibility allowed by the Stipulated Plan is appropriate and still protects the affordability of basic local exchange service. Prices for Moderate Pricing Flexibility Services in the aggregate can increase no more than the one and one half times the change in GDPPI. Aggregate price increases for rate elements in this category above this rate must be accompanied by commensurate (offsetting) aggregate price reductions in other rate elements. The Stipulated Plan further protects the affordability of local exchange services by generally limiting the potential annual price increase for any single rate element to ten percent (10%) for services in the Moderate Pricing Flexibility basket and twenty percent (20%) for services in the High Pricing Flexibility basket.

In reaching this conclusion, the Commission notes that the last general rate case involving any of the TDS Companies was almost over 15 years ago, and current rates were set under circumstances very different from those in existence today. The record shows that in the past four years, Barnardsville and Saluda Mountain have collectively lost more than 7.5% of their customer base and Service has lost nearly 5% of its access lines since 2004, as a result of changes in technology and competition. In contrast, when the TDS Companies' current rates were adopted there was no competition for basic service. The limited increase in pricing flexibility allowed under the Stipulated Plan for basic local exchange services and discretionary services is fully justified by the increased competition that exists in the TDS Companies' North Carolina telecommunications market. It is also consistent with increased pricing flexibility approved for other North Carolina incumbent LECs.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 3 - SERVICE QUALITY

Finding of Fact and Conclusion of Law No. 3 was not disputed by any party. In the Stipulated Plan there are provisions expressly relating to service quality measurements and provision for appropriate service quality penalties. The Commission retains powers and authority with regard to the provision of quality service. The TDS Companies will continue to operate under Commission Rule R9-8 and will be subject to the service quality penalties set forth in the Stipulated Plan. Furthermore, the Commission will retain oversight for service quality, complaint resolution, and compliance with all elements of the Stipulated Plan and applicable state law.

Thus, the Commission concludes that the Stipulated Plan reasonably assures the continuation of basic local exchange service that meets the reasonable service standards established in Commission Rule R9-8.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 4 - NO PREJUDICE AMONG CUSTOMER CLASSES

TDS witness Meade's testimony addressed the issue of whether the Stipulated Plan will unreasonably prejudice any class of telephone customers. He stated that, for several reasons, the Stipulated Plan will not result in such prejudice. First, he asserted that the TDS Companies will continue to charge tariffed rates for services on nondiscriminatory terms and conditions and that those prices will be restrained by the Stipulated Plan's pricing limits and by competition.

Second, customers in a position to negotiate customer-specific agreements will obtain prices that are constrained by the existence of competitive alternatives.

Third, the Stipulated Plan does not change any terms and conditions applicable to the TDS Companies' relationships with other carriers, such as the terms of access tariffs, interconnection agreements, or wholesale service arrangements and numbering, and applicable non-discrimination requirements remain in effect.

Finally, the Stipulated Plan uses existing rates as a starting point and therefore preserves the pricing for basic residential services. At the same time, the Stipulated Plan permits the TDS Companies to modify their basic residential prices, over time, without necessarily making corresponding changes in basic business prices that begin at higher levels. In this way, the Stipulated Plan preserves a balance between the treatment that residential customers have traditionally enjoyed and the possibility that basic business rates may require a somewhat different treatment in the future because they are more competitive.

Public Staff witness Moye did not take issue with witness Meade's analysis and agreed that the Stipulated Plan will not be unreasonably prejudicial to customers.

The Commission finds the testimony of witnesses Meade and Moye to be persuasive and concludes that the Stipulated Plan will not unreasonably prejudice any class of telephone customers, including telecommunications companies.

DISCUSSION OF FINDING OF FACT AND CONCLUSION OF LAW NO. 5 - PUBLIC INTEREST STANDARD

The public interest standard is one the Commission has employed in its deliberations for many years. The Commission finds the Stipulated Plan to be in the public interest for several reasons. First, it permits the rate rebalancing necessary for the ongoing transition to competition, without allowing the rebalancing process to proceed at such a rapid pace as to impose an undue burden upon those customers whose rates may increase. Second, the Stipulated Plan provides affordable rates and assures that the TDS Companies will continue to provide adequate service to their customers. Third, the Stipulated Plan contains specific service performance measures and penalties. Fourth, the Commission believes that a competitive marketplace is consistent with the goals established by the legislature, and will engender significant benefits for the citizens of the State through improved services, generally lower prices, and greater technological innovation, and that it will therefore offer significant potential for enhanced economic development.

At the same time, the Commission recognizes that the public interest could be adversely affected if telecommunications services were fully deregulated, or regulated so lightly that the only limitations on prices were those imposed by competition, at a time when competition has not yet progressed to the point where it could discipline prices effectively in the TDS Companies' North Carolina service territories.

In addressing this concern, the Commission notes that there is a close correlation between the assignment of telecommunications services to pricing categories under the

Stipulated Plan and the degree of competition for particular services in the TDS Companies' service areas. The assignment of services to categories in the Stipulated Plan was determined by negotiation between the TDS Companies and the Public Staff; however, the services assigned to the Total Pricing Flexibility Services category are those to which the greatest degree of competition exists. In contrast, the services categorized as Moderate Pricing Flexibility Services are those for which competition is less vigorous. The Commission finds it significant that the Public Staff, which is responsible under G.S. 62-15 for protecting the interests of the using and consuming public, has been willing to agree to the Stipulated Plan. Under the Stipulated Plan, the Commission will retain sufficient authority to monitor and maintain service quality, to review rate structures and the terms and conditions of tariffs against public interests standards, to decide complaints concerning anticompetitive behavior, and to oversee the reclassification and regrouping of services and the financial impacts of governmental actions.

In addition, the Commission notes that although four hearings were held, no public witnesses testified in opposition to the Stipulated Plan.

Although the Commission is concerned about the lack of provisions in the Stipulated Plan that would allow the Commission to revisit the Plan in the event a change of circumstances or events should require, this concern does not. given the evidence in the record, justify a refusal to approve the Stipulated Plan.

Accordingly, while still concerned about the irreversible nature of the Stipulated Plan, the Commission nevertheless concludes that the provisions of the Stipulated Plan are sufficiently limited, and that the Stipulated Plan is consistent with the public interest given the current level of competition in the TDS Companies' service territories. Furthermore, the Commission recognizes that, under the Stipulated Plan, it retains the regulatory oversight authority for any request by the TDS Companies to classify new services or reclassify existing services to a Category providing greater pricing flexibility. This continuing authority regarding the appropriate classification of services is important, as it enables the Commission going forward to ensure that each request to classify or reclassify services is supported by a showing of increased competition for these services.

FINAL OBSERVATIONS AND CONCLUSIONS

Consistent with the law and policy of this State, the TDS Companies and the Public Staff have negotiated a Stipulated Plan that meets each of the criteria prescribed by G.S. 62-133.5(c) and therefore the Commission finds that approval of the Stipulated Plan is appropriate. The Commission has approved similar price plans for similarly situated companies. The Stipulated Plan in this case has many elements in common with these previously approved price regulation plans. The record shows that the competitive landscape has changed considerably since 1996. The Commission believes that the flexibility afforded by the Stipulated Plan will enable the TDS Companies to compete effectively and continue to provide reasonably affordable basic local exchange service. The Commission's decision to approve the Stipulated Plan is based upon its analysis of competitive conditions in the TDS Companies' service territories, and should not be understood as indicating that a different plan would not be appropriate given the existence of different competitive conditions.

IT IS, THEREFORE, ORDERED that the Stipulated Plan be. and the same is hereby, approved for implementation by the TDS Companies effective no later than May 22, 2007, provided that the TDS Companies shall, not later than May 11, 2007, refile the Stipulated Plan bearing an effective date not later than May 22, 2007.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of May, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Pb050907.04

DOCKET NO. P-1262, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Arbitration of Time Warner Cable	)	
Information Services (North Carolina), LLC	)	RECOMMENDED
for Arbitration with LEXCOM Telephone	)	ARBITRATION ORDER
Company	)	

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, Sam J. Ervin, IV, and Commissioner William T. Culpepper, III

BY THE COMMISSION: On March 30, 2007 Time Warner Cable Information Services (North Carolina), LLC (TWCIS), filed a petition for arbitration with LEXCOM Telephone Company (LEXCOM), pursuant to Section 252(b) of the Communications Act of 1934, as amended (the Act). TWCIS requested a waiver of the Commission's requirement regarding the simultaneous filing of testimony as part of its petition for arbitration.

On April 2, 2007 the Commission issued an order granting a waiver of the simultaneous filing requirement and establishing deadlines for the filing of testimony by the parties.

LEXCOM filed a response to the TWCIS petition on April 20, 2007.

On May 1, 2007 TWCIS filed a reply and also filed the direct testimony of Maribeth Bailey. LEXCOM filed the direct testimony of Donna K. Arnold on May 29, 2007, and TWCIS filed the rebuttal testimony of Witness Bailey on June 7, 2007.

On August 15, 2007 TWCIS and LEXCOM filed a Joint Proposed Procedural Schedule and Request for Decision Without Hearing requesting that LEXCOM be given the opportunity to file surrebuttal testimony by a prescribed date; that a date be set for the filing of briefs and proposed orders; and that the matter be decided on the basis of the prefiled testimony without a hearing.

In an order issued on August 17, 2007, the Commission granted the parties' request that the matter be decided without a hearing, established deadlines for the filing of surrebuttal testimony by LEXCOM and briefs and proposed orders by all parties, and authorized the Public Staff to file a proposed order or brief.

LEXCOM filed the surrebuttal testimony of Witness Arnold on August 31, 2007. Briefs or proposed orders were filed by all parties on September 12, 2007.

Based on the foregoing, the parties' prefiled testimony, and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

1. LEXCOM negotiated in good faith, and no full and binding agreement was reached at the conclusion of the parties' negotiations.

2. The interconnection agreement (ICA) between the parties should include language under which LEXCOM indemnifies TWCIS for liability incurred by TWCIS as a result of LEXCOM's negligence in connection with directory listings for TWCIS end users.

3. The sentence proposed by LEXCOM referencing section 6 of LEXCOM's General Customer Services Tariff, and objected to by TWCIS, should not be included in the ICA.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

POSITIONS OF PARTIES

TWCIS: TWCIS argues that a binding agreement was reached as to all of the provisions of the ICA during the negotiation process. The redlined agreement presented as Exhibit 7 of the Petition memorializes all the terms and conditions of the ICA, including TWCIS's acceptance of LEXCOM's pricing proposal. LEXCOM has not negotiated in good faith.

LEXCOM: LEXCOM argues that no binding agreement could be reached concerning the provisions of the ICA until all the provisions had been reviewed and approved by LEXCOM's president. After LEXCOM's president reviewed the interim agreement, a revised ICA was later circulated to TWCIS.

PUBLIC STAFF: The record does not show that LEXCOM failed to negotiate in good faith.

DISCUSSION

It is not often that an arbitration proceeding comes before this Commission in which one of the parties argues that there should not be an arbitration because the disputed matters have already been resolved. Nevertheless, that has happened in this docket. TWCIS has argued that a full, binding agreement has been reached and that LEXCOM should not be allowed to reopen issues about which the parties previously reached agreement. This, on its face, constitutes a threshold issue in need of resolution before the issues that are actually contested in this arbitration can be addressed.

It is clear from the evidence that LEXCOM did not consider that its agents, Mr. Scott and Ms. Arnold, were fully empowered to conclude an agreement with TWCIS until LEXCOM's upper management—principally, its president, Mr. Reese—had reviewed it. LEXCOM argued that, as a small company engaged in its first negotiation of an ICA with a competing local provider, this approach was entirely reasonable. The evidence also shows that TWCIS did not believe that Mr. Scott and Ms. Arnold were *not* fully empowered to reach a binding agreement. There was a difference of opinion as to whether LEXCOM had conveyed to TWCIS on a timely basis the limits on its negotiators' authority to reach a final agreement. In any event, TWCIS construed LEXCOM's course of behavior toward the end of negotiations in referring the contract to its president as an example of LEXCOM negotiating in bad faith and, for that reason, argued that the Commission should rule in TWCIS's favor on the issues actually disputed.

Certainly, both the Telecommunications Act and accompanying rules provide that incumbent local exchange companies are required to negotiate in good faith. For example, 47 C.F.R. 51.301(a) provides that "[a]n incumbent LEC shall negotiate in good faith the terms and conditions of agreements to fulfill its duties established by section 251(b) and (c) of the Act." Further, 47 C.F.R. 51.301(c) provides that "the following actions or practices, among others, violate the duty to negotiate in good faith: . . . (3) Refusing throughout the negotiations process to designate a representative with authority to make binding representations, if such refusal significantly delays resolutions of issues." However, in its *Interconnection Order*,[1] the Federal Communications Commission (FCC) noted at paragraph 154 that "it is unreasonable to expect an agent to have authority to bind the principal on every issue—i.e., a person may reasonably be an agent of limited authority."

LEXCOM's apparent position is that its negotiator possessed no authority to bind it and that the negotiators' decisions concerning all issues must be referred to upper management for ultimate approval. Limited authority to bind is recognized by the FCC; no authority to bind is more problematical. The applicable test is whether the refusal to designate a representative with authority "significantly delays resolution of the issues." In the instant case, LEXCOM's president responded in a timely manner with approximately 16 changes, all of which were accepted TWCIS except the two which have become the subject of this arbitration.

If a company abuses the management review process by changing its position arbitrarily for the purpose of delay and such delay occurs, such conduct could violate the general obligation of good faith set forth in section 51.301. However, the record does not show that such an abuse occurred in the negotiations between TWCIS and LEXCOM. LEXCOM's late day reference of the contract to its president may have been exasperating to TWCIS, but it was not abusive. It is not unreasonable that a small company such as LEXCOM would wish to have a contract reviewed by its president.

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[1] *Implementation of the Local Competition Provisions in the Telecommunications Act of 1996, Interconnection Between Local Exchange Carriers and Commercial Mobile Radio Service Providers*, CC Docket Nos. 96-98, 95-185, First Report and Order, 11 FCC Rcd. 15499 (1996).

Nevertheless, it is regrettable that the parties were not clearer in their dealings with each other regarding the extent of their negotiators' authorities. The Commission therefore admonishes that, early on in any future negotiations with each other or with other parties, TWCIS should specifically ask and LEXCOM should specifically tell the other party the precise limits, if any, of their negotiators' authority so that misunderstandings of this nature will not occur again.

CONCLUSION

The Commission concludes that LEXCOM negotiated in good faith and that no full and binding agreement was reached at the conclusion of the negotiations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

ISSUE NO. 2: Should LEXCOM be immune from liability for its negligence in connection with directory listings services provided to TWCIS?

POSITIONS OF THE PARTIES

TWCIS: No. LEXCOM should not be entitled to disclaim all liability for errors or omissions in its handling of directory listings, including errors and omissions that are the result of negligence.

LEXCOM: Yes. LEXCOM should be immune from liability in connection with the performance of its directory obligations under the interconnection agreement, including errors and omissions that are a result of negligence.

PUBLIC STAFF: No. LEXCOM should not be entitled to disclaim all liability for errors or omissions in its handling of directory listings, including errors and omissions that are the result of negligence. The language proposed by TWCIS, with the correction of a typographical error in section 9.9, which does not require TWCIS to indemnify LEXCOM for liability arising out of LEXCOM's negligence, is preferable to the broader indemnity obligation that LEXCOM's language would impose.

DISCUSSION

This issue concerns LEXCOM's proposed revision to Section 9.9 and 9.10 of the draft interconnection agreement. In LEXCOM witness Arnold's testimony, she stated that the revision being proposed was based upon the provisions of Section 2.5.5 of LEXCOM's General Customer Service Tariff (GCST). In that section, LEXCOM "assumes no liability for damage claimed on account of errors or omission from its directories and, in accepting listings as prescribed by applicants or customers, will not assume responsibility for the result of their publication in the directory." LEXCOM does not believe that it should be forced to agree to language in an ICA which would be inconsistent with the terms of its tariff or which would potentially expose it to any liability beyond what it would accept as to its own customers. Thus, LEXCOM has excised those portions of the Section 9.9 and 9.10 of the ICA which would expose it to any liability for any acts of negligence on its part or the part of any third party retained or employed by LEXCOM. Briefly summarized, LEXCOM's position on this issue is based on the following: (1) LEXCOM directories are handled by a third-party publishing company, so it should not bear any responsibility for errors caused by this third party; (2) LEXCOM's retail tariff provides that it bears no liability to its end users for errors or omissions in directory listings, so LEXCOM should have no greater liability to TWCIS than it has to its end users; and (3) various Time Warner Cable entities have adopted similar disclaimers of liability in other ICAs, and such disclaimers are standard in the industry.

TWCIS argues that LEXCOM should not be entitled to disclaim all liability for errors or omissions in its handling of directory listings, including errors and omissions that are a result of negligence. Testimony from TWCIS witness Bailey indicates that TWCIS bases its position on the obligations that carriers owe to other carriers under federal law and the fact that these obligations differ from the obligations that carriers owe to retail customers. *See* Bailey Direct, at 13; Bailey Rebuttal, at 6-7. In its brief, TWCIS further argued that the ICA provisions cited by LEXCOM did not support LEXCOM's position but rather supported TWCIS, and that limitations of liability by public utilities are against State public policy.

In its Proposed Order, the Public Staff contends that LEXCOM should not be entitled to disclaim all liability for errors or omissions in its handling of directory listings, including errors and omissions that are the result of negligence. Further, the Public Staff stated that the language proposed by TWCIS, with the correction of a typographical error in section 9.9, which does not require TWCIS to indemnify LEXCOM for liability arising out of LEXCOM's negligence, is preferable to the broader indemnity obligation that LEXCOM's language would impose.

Since the parties are in good-faith disagreement as to the indemnity language to be included in sections 9.9 and 9.10 of the ICA, the Commission must resolve the issue. In her testimony, LEXCOM witness Arnold stated that LEXCOM does not publish its own directory and contends that this fact supports shielding it from liability for directory publishing errors. It is indeed true that LEXCOM does not publish its own directory and has chosen instead to contract with a third party to publish the directory. In the telecommunications industry, it is a fairly common practice for third parties to assume responsibility for publication of LEC directories. It is also most certainly true that the Commission has, in the past, allowed LEXCOM to limit its liability to its retail customers for publication errors in its directories by approving a tariff which states that LEXCOM "assumes no liability for damage claimed on account of errors or omission from its directories and, in accepting listings as prescribed by applicants or customers, will not assume responsibility for the result of their publication in the directory." Even though it is a fairly common practice for a third party to publish the directory and even though the Commission has allowed a LEC to limit its liability to its retail customers for publication errors in its directories, the ultimate responsibility and the liability attendant therewith for providing directories and ensuring the correctness of the listings contained therein remains with the LEC under the Telecommunications Act. *See* 47 U.S.C. 251(b)(3).

The Telecommunications Act permits an ILEC such as LEXCOM to shift some or all of its liability for ensuring the accuracy of the directory from the LEC to a competitor of the ILEC, such as TWCIS, through good faith negotiations. Thus, the parties may, through negotiation and agreement, absolve or limit an ILEC's financial responsibility for its negligent acts that damage a competitor such as TWCIS. The negotiations between LEXCOM and TWCIS have not resulted in such an agreement. In the absence of such negotiated agreement, the Commission believes that it is unwise to allow LEXCOM to disclaim any and all liability for errors or omissions in its handling of directory listings, including errors and omissions that are a result of its negligence. Were it to do so, the Commission would be allowing LEXCOM to shift complete responsibility for ensuring the accuracy of the directory from LEXCOM, the entity that has statutory responsibility for providing the directory, to TWCIS, a party that is, by statute, entitled to nondiscriminatory access to directory listings and, more importantly, a competitor with the ILEC in the telecommunications services market.

In reaching this decision, the Commission acknowledges that it has previously approved broadly worded provisions in retail tariffs that relieved LEXCOM of liability for errors and omissions in directory listings, even when caused by the LEXCOM's negligence. By definition, those tariff approvals primarily affected LEXCOM's retail customers and did not affect the obligations that a carrier owes to other carriers such as CLPs under federal law. In the Commission's opinion, this is a very important distinction. An ILEC has every incentive to list its retail customers correctly in its directory; any error that occurs is likely to be an isolated aberration. In contrast, if it becomes apparent that CLP customers are often being listed incorrectly in an ILEC's directory, customers will be motivated to take service from the ILEC rather than the ILEC's competitor, the CLP. The prospect of being held liable for directory listing errors resulting from its own negligence will tend to limit any incentive that may otherwise exist for an ILEC to seek to obtain a competitive advantage through questionable means.[1] A policy which encourages this result fosters the pro-competitive policies embodied in the Telecommunications Act.

Consistent with its retail tariffs, LEXCOM has proposed that it be completely absolved of any liability for its negligence or the negligence of a third party publisher employed by it in the publication of its directory. By contrast, TWCIS has proposed that LEXCOM's should be subject to some limited liability for publication errors resulting from its negligence or the negligence of a third party publisher employed by LEXCOM. In the Commission's judgment, the language proposed by TWCIS, which does not require TWCIS to indemnify LEXCOM for liability arising out of LEXCOM's negligence, is preferable to the broader indemnity obligation that LEXCOM's language would impose. Under the language proposed by TWCIS, if a TWCIS customer is improperly listed because of an error on the part of the publisher hired by LEXCOM, it is likely that LEXCOM will not be found negligent; thus, the indemnity exception proposed by TWCIS will have no application. In the event that LEXCOM is found liable for an error even though the primary fault is that of the publisher, LEXCOM should be able to obtain reimbursement from the publisher under common-law principles.

Finally, the Commission notes Witness Arnold's claim that LEXCOM's language is similar to that adopted by TWCIS in other ICAs. In the Commission's opinion, there is a distinct difference between the broad indemnity language proposed by LEXCOM and the more limited indemnity language included in the ICA between ALLTEL Carolina and Time Warner Telecom

[1] The Commission is not, of course, suggesting that LEXCOM or any other North Carolina ILEC would yield to the temptation to act unscrupulously – only that a deterrent mechanism will prevent any temptation from arising.

or the agreement adopted by TWCIS between North State Communications and MCImetro. The examples included in the surrebuttal testimony of Witness Arnold clearly reflect language that speaks to the limitation of the losses or damages except those that result from gross negligence or willful misconduct of the ILEC. In each of those examples, the ILEC had some continuing responsibility for its misconduct and was not completely absolved of liability as LEXCOM herein proposes. In the Commission view, it is appropriate that LEXCOM have, in some form, continuing responsibility for ensuring the accuracy of its directory in the absence of an agreement with its competitor absolving it of all responsibility for publication errors. Since LEXCOM's proposal eliminates any possibility that it will be held accountable for any listing errors by either LEXCOM or its third party publisher, the Commission rejects LEXCOM's proposal and adopts the proposal made by TWCIS.

In doing so, the Commission notes an apparent typographical error in the language proposed by TWCIS. The second sentence of section 9.9 of the ICA, as proposed by TWCIS, contains the phrase "its and LEXCOM's to TWCIS (NC) End User Customers." The Commission believes that a word was inadvertently omitted, and that this phrase should read "its and LEXCOM's liability to TWCIS (NC) End User Customers."

With this minor correction, the Commission concludes that the language proposed by TWCIS for sections 9.9 and 9.10 of the ICA should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

ISSUE NO. 3: Should the sentence proposed by LEXCOM, referencing section 6 of LEXCOM's General Customer Services Tariff (GCST), and objected to by TWCIS, be included in section 9.1 of the ICA?

POSITIONS OF THE PARTIES

TWCIS: No. TWCIS's position is that language referencing Section 6 of LEXCOM's General Customer Service Tariff should not be included because it is directed towards end-user, retail customers and has no bearing on the carrier-to-carrier relationship established by the ICA. Additionally, the provisions of the general subscriber tariff differ in some respects from the directory listings criteria and standards negotiated between the Parties.

LEXCOM: Yes. LEXCOM favors language referencing Section 6 of its General Customer Service Tariff primarily for purposes of clarity concerning the format of directory listings.

PUBLIC STAFF: No. The sentence in Section 6 of LEXCOM's General Customer Service Tariff should not be included in the interconnection agreement.

DISCUSSION

At the outset, the Commission notes that LEXCOM contends that this issue has not been properly brought forward for arbitration, because TWCIS raised only one issue in its petition – the issue relating to liability for errors and omissions in directory listings resulting from

LEXCOM's negligence – and because it identified this second issue only in its reply, filed after the deadline established by the Act had passed. With respect to this assertion, the Commission finds that it was LEXCOM who initially proposed inserting the sentence in question, following its president's review of the proposed ICA at the conclusion of the negotiating process. The evidence presented shows that the sentence at issue did not appear in the proposed ICA attached to the initial TWCIS petition; rather it seems to have first appeared as an unhighlighted change to the interconnection agreement LEXCOM provided to TWCIS after LEXCOM's president had completed his review.

Further, the Commission finds that, in its Petition for Arbitration, TWCIS made clear that it sought adoption of the ICA resulting from the negotiations of the parties' respective negotiating teams. See Petition for Arbitration, Exhibit 7. In its response, LEXCOM noted that it sought additional changes to Exhibit 7, other than the changes identified by TWCIS in its original matrix and stated that it would seek arbitration of this additional language if TWCIS did not accede to it. In response, TWCIS submitted, without objection, a revised matrix reflecting the additional change not agreed to by TWCIS and, subsequently, both parties filed testimony setting forth their respective positions on this issue. These filings were entirely consistent with the procedure set forth in 47 U.S.C, 252(b) of the Telecommunications, Act which expressly provides that the Commission may resolve any issue presented to it in either the Petition or the response. *See* 47 U.S.C. 252(b)(4)(A). For this reason, the Commission finds that this issue has been properly raised by TWCIS. Moreover, the Commission believes that, as a matter of fairness, LEXCOM should not be allowed to propose the inclusion of this sentence and then contend that TWCIS has no right to challenge it.

With regard to the substantive issue, LEXCOM proposes to insert into section 9.1 of the ICA the following sentence: "All directory listings will be handled in accordance with the provisions of Section 6 of LEXCOM's General Customer Service Tariff." TWCIS witness Bailey testified that this sentence should not be included because the GCST is designed to address end user issues, not carrier-to-carrier issues. Moreover, according to witness Bailey, the two companies' subject matter experts met during the negotiations and agreed on the procedures to be followed by TWCIS in submitting directory listings to LEXCOM, and some of these procedures – which are set out in MB Direct Exhibit 7 – are not identical to the provisions of the GCST. Witness Bailey also expressed concern that the inclusion of a reference to the GCST, with its provision excluding all liability on LEXCOM's part for errors and omissions in directory listings, might be inconsistent with the position of TWCIS that LEXCOM should not be immunized from liability for its own negligence.

LEXCOM Witness Arnold testified that section 6 of the GCST specifies the format to be used for listings in LEXCOM's directory, and it is appropriate to reference this section in the ICA. She stated that, in her opinion, there is no real dispute between the parties on this matter, since the sentence that will immediately follow the contested language in section 9.1 of the ICA provides: "Listing inclusion in a given directory will be in accordance with LEXCOM's solely determined directory configuration, scope, and schedules, and listings will be treated in the same manner as LEXCOM's listings." According to LEXCOM, the disputed sentence merely confirms, and adds nothing substantive to this sentence to which TWCIS has agreed.

After carefully examining the contentions of the parties, the evidence presented, the language proposed in the ICA and the GCST, the Commission agrees with TWCIS that the disputed sentence should not be included in the ICA. In her testimony, LEXCOM witness Arnold acknowledged that the disputed sentence is not intended to add anything substantive to the sentence that comes after it. The Commission agrees with this assessment. In its view, the parties have reached consensus on the main issue, the proposed sentence adds nothing to substance to the section, and it has the potential to unnecessarily create confusion where there would otherwise be none. Accordingly, the Commission concludes that the sentence proposed by LEXCOM for inclusion in section 9.1 of the ICA should not be included.

IT IS, THEREFORE, ORDERED as follows:

1. That TWCIS and LEXCOM 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 30 days after the issuance of this Recommended Order, any interested party to the arbitration may file objections to this Recommended Order consistent with paragraph 3 of the *Arbitration Procedure Order.*

3. That, not later than 30 days after the issuance of this Recommended Order, 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 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, on an MS-DOS formatted 3.5-inch computer diskette containing the noncompressed files created or saved in Microsoft Word format.

ISSUED BY ORDER OF THE COMMISSION.

This the 26th day of November, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

DI112607.01

WATER AND SEWER – COMPLAINT

DOCKET NO. W-1143, SUB 8

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Charlie C. Gregory, 812 Willbrook Circle, Sneads Ferry, North Carolina 28460, Complainant v. North Topsail Utilities, P.O. Box 240908, Charlotte, North Carolina 28224, Respondent	)))))))))	RECOMMENDED ORDER DENYING COMPLAINT

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Thursday, June 28, 2007, at 9:00 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; Commissioners Robert V. Owens, Jr., and William T. Culpepper, III

APPEARANCES:

For Complainant:

Daniel F. Hayes, 540 Lexington Avenue, 16th Floor, New York, New York 10022 (*Pro Hac Vice*)

For Respondent:

Christopher J. Ayers, Hunton & Williams, Attorneys-at-Law, Post Office Box 109, Raleigh, North Carolina 27602

BY THE COMMISSION: On February 28, 2007, Charlie C. Gregory (Complainant) filed a complaint with the Commission against North Topsail Utilities (Respondent) alleging it refused to honor a commitment to transfer sewer connections from two properties he owns in Sneads Ferry to two properties he owns on North Topsail Island. Complainant further alleges that Respondent's transfer policy is discriminatory and unreasonable, in violation of N.C.G.S. 62-140(a). He requests that the Commission enforce the alleged agreement and order the Respondent to transfer the sewer connections.

On March 22, 2007, the Respondent filed its Answer and Motion to Dismiss. In its motion, Respondent argued that the complaint should be dismissed for failure to state a claim upon which relief could be granted.

On March 27, 2007, the Commission issued an Order Serving Answer on Complainant for review and response. The Commission did not address Respondent's motion to dismiss.

On April 12, 2007, Complainant filed a Reply wherein he indicated that Respondent's Answer was not satisfactory and requested a hearing on his complaint.

On April 23, 2007, the Commission issued an Order Serving the Reply on Respondent. That Order directed the Respondent to review the filing and to submit any additional information to the Commission before any further action was taken.

On April 30, 2007, the Respondent filed a response to Complainant's Rely which addressed the additional concerns raised by the Complainant. Respondent renewed its motion to dismiss the complaint on the grounds that it fails to state a claim upon which relief could be granted by the Commission.

On May 14, 2007, the Commission issued an Order Denying Respondent's Motion to Dismiss and Scheduling this matter for hearing.

This matter came on for hearing on June 28, 2007. Complainant testified in support of his complaint. Complainant also offered the testimony of Richard J. Durham, Respondent's Regional Director, and Lillian Trifoli, Respondent's customer service representative. Additionally, the Complainant submitted exhibits and other documents related to Respondent's transfers of sewer connections. The proffered records and documents were admitted into evidence without objection.

Based on the foregoing, the evidence introduced at the hearing and the entire record in this docket, the Commission makes the following:

FINDINGS OF FACT

1. Respondent is a duly franchised public utility as defined by G.S. 62-3(23).

2. Respondent provides sewer utility service in North Topsail Beach and certain other areas on the mainland of Onslow County pursuant to a certificate of public convenience and necessary granted by the Commission on June 28, 2000.

3. Complainant is a developer and builder in the North Topsail vicinity. Prior to November 2005, Complainant visited the office of Respondent on several occasions to inquire about the availability of sewer connections for properties on North Topsail Beach. Complainant learned that he was number 119 on the list to receive sewer service.

4. In November 2005, Complainant visited the Respondent's office and spoke with customer service representative Lillian Trifoli and generally inquired about the ability to transfer sewer capacity from a lot in Sneads Ferry to a lot at North Topsail Beach.

5. During Complainant's November 2005, visit to Respondent's office, Complainant did not identify or otherwise refer specifically to any lot(s) in Sneads Ferry from which he wished to transfer sewer capacity.

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6. Ms. Trifoli informed Complainant that Respondent could transfer capacity from a lot in Sneads Ferry to a lot in North Topsail Beach provided that he owned both lots.

7. During Complainant's November 2005, visit to Respondent's office, Complainant did not identify any specific lot(s) on North Topsail Beach to which he wished to transfer the sewer capacity.

8. Complainant did not request and was not provided a copy of Respondent's transfer policy.

9. Complainant did not request that Respondent put its answer to him in writing.

10. Complainant had no other conversation with Ms. Trifoli about the possibility of transferring the sewer connections relating to any Sneads Ferry properties.

11. In December 2005, Complainant entered into a contract to purchase a lot at 271 Clay Hill in Sneads Ferry for $48,000.

12. In February 2006, Complainant entered into a contract to purchase a second lot at 273 Clay Hill in Sneads Ferry for $35,000.

13. At the time Complainant purchased the two lots in Sneads Ferry, each had a single-wide mobile home on them that was being serviced by a simplex sewer pump.

14. In March 2006, the Complainant returned to Respondent's office to inform Ms. Trifioli that he had purchased one property in Sneads Ferry and was closing on a second, and wanted to find out how to complete a transfer.

15. When Complainant provided Ms. Trifoli with the addresses of the Sneads Ferry properties which he purchased, Ms. Trifoli recognized the addresses as having existing sewer service. She informed the Complainant that there was a problem and that he would not be able to transfer capacity from these properties and immediately referred the matter to her superior, Eddie Baldwin.

16. Mr. Baldwin explained to the Complainant that he could not transfer sewer service from the properties in Sneads Ferry to properties on North Topsail Beach because the properties in Sneads Ferry had existing sewer service and it would be against the transfer policy.

17. The Complainant thereafter spoke with Jim Highley, Senior Regional Manager for Respondent's corporate parent Utilities, Inc., who confirmed the policy and notified the Complainant that he would not be allowed to transfer the capacity from the properties on Sneads Ferry to North Topsail Island.

18. The Complainant then contacted Mr. Rich Durham, Respondent's Regional Director, who informed him as a result of the policy he would not receive the service he requested.

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19. Respondent maintains a policy whereby owners of an unimproved or uninhabitable lot can transfer capacity from that lot to another provided that the owner owns both lots.

20. Respondent does not permit its customers to terminate existing sewer service on one lot and transfer that flow to a different lot. Once a customer is online, the flow cannot be transferred. An exception to this policy exists when a lot with existing sewer service is destroyed and rendered unbuildable. In such circumstances, lot owners may transfer capacity from such a lot to a buildable lot that they own.

21. Several property owners have been allowed to transfer sewer service under the parameters of the transfer policy.

22. Complainant is the first individual who has attempted to transfer existing sewer service from a habitable lot to a vacant lot.

23. Respondent acquired the assets comprising the Respondent system from the bankruptcy trustee through the bankruptcy court proceeding in 1999.

24. At the time of acquisition, the permitted capacity at the waster water treatment system had been substantially reduced from the permitted capacity of 877,000 gpd to 629,000 gpd due to improper operations.

25. In June 2002, the Respondent entered into a contractual agreement with Mr. Mark Evans, a developer, to provide him with 167 sewer taps, at a time when sufficient sewer capacity existed on the system and <u>before</u> the waiting list was created in March 2003. Mr. Evans' agreement with the Respondent also provided a source of funds of $150,000 for the Respondent to draw upon to fund necessary improvements to the sewer system.

26. Respondent has expended hundreds of thousands of dollars on the waste water treatment system to recover the lost capacity.

27. All capacity that can be recovered in the waste water treatment system as it is currently constructed has been recovered.

28. As lost capacity was recovered, this capacity was allocated to customers pursuant to a waiting list established by Respondent in March 2003.

29. Beginning in March 2005, Respondent implemented a policy limiting customers on the waiting list to eight taps when Respondent got its allocation from the Division of Water Quality.

30. Future additional capacity will only be available through an expansion of the existing system. As there is no remaining lost capacity to recover, the waiting list has become obsolete because once the system is expanded sufficient capacity will exist to serve all customers.

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DISCUSSION AND ANALYSIS

This matter arose out of a dispute between Complainant and Respondent concerning Respondent's refusal to permit Complainant to transfer sewer capacity. Specifically, Complainant alleges that Respondent's employee, Lillian Trifoli, agreed to the transfer and subsequently failed to honor its agreement to permit him to transfer sewer capacity assigned to lots he owned in Sneads Ferry to undeveloped property he owned on North Topsail Island. Complainant also contends that Respondent's failure to honor the agreement constitutes an unreasonable and discriminatory application of its transfer policy. Complainant requests that the Commission enforce the commitment and order the Respondent to transfer the sewer service to its properties in North Topsail Island.

Complainant fails to meet his burden of proof as required under G.S. 62-75.

Complainant argues that Ms. Trifoli, in her capacity as Respondent's authorized representative, agreed to transfer sewer capacity assigned to two lots in Sneads Ferry to undeveloped lots that he owned on North Topsail Island. Complainant asserts that he relied upon Ms. Trifoli's statement or agreement that he would be permitted to transfer the capacity when he purchased the Sneads Ferry properties. Complainant contends that Respondent is required to honor the commitment made to him by Ms. Trifoli

Pursuant to G.S. 62-75, the burden of proof in complaint proceedings is on the complaining party to present persuasive evidence against the public utility to prove that the action taken by the utility is unjust and unreasonable. If Complainant is to prevail in this case, he must show that his inquiry of Ms. Trifoli constituted an agreement to transfer sewer capacity, that Ms. Trifoli was authorized to enter into the alleged agreement, and that Respondent's refusal to transfer sewer service to Complainant's properties on North Topsail Island is unjust and unreasonable. For the reasons which follow, the Commission concludes that Complainant has not met that burden.

An agreement is defined as a concord of understanding and intention between two or more parties with respect to the effect upon their relative rights and duties, of certain past or future facts or performances.[1] A valid agreement arises only where the parties assent to the same thing in the same sense and their minds meet as to all terms.[2] There must be mutual agreement to all terms.[3]

Despite the Complainant's assertions, the evidence shows that there was no meeting of the minds between him and Ms. Trifoli regarding the transfer of sewer capacity from the properties at 271 Clay Hill and 273 Clay Hill in Sneads Ferry to his property on North Topsail Island.

Complainant testified that when he initially began to stop by Respondent's office to inquire about sewer availability, he was concerned about obtaining service for his home on North

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[1] Black's Law Dictionary 67 (6th ed. West Publishing Co., 1990).
[2] *Id.*
[3] *Id.*

Topsail Island. In November 2005, Complainant visited Respondent's office and again inquired about sewer availability; this time, however, he was interested in obtaining service to surplus property on North Topsail Island that he acquired from Onslow County. According to Complainant, he asked Ms. Trifoli, "If I had properties in Sneads Ferry with taps could I transfer those taps to North Topsail beach where we had other properties?"[1] Ms. Trifoli responded, "Yes, I see no problem with that as long as one person owns both properties."[2] Complainant testified that he purchased the Sneads Ferry lots for the sole purpose of obtaining the sewer connections to transfer to the North Topsail property so that he would resell that property to a builder. He asserted that he would not have purchased those lots if Ms. Trifoli had told him that he could not transfer the taps. No additional details were provided or requested and the discussion was not reduced to writing.

Ms. Trifoli testified that she had been employed as Respondent's Customer Service Representative for almost seven years and that no one else had ever requested to transfer sewer allocation from a property that was currently receiving sewer service and had an installed tap. Had she known Complainant intended to transfer capacity from a property that was currently receiving sewer service she would have explained that Respondent's policy did not permit such transfers. It was only when Complainant returned to her office and provided her with the addresses of the Sneads Ferry properties that she realized what he intended to do. She testified that she immediately referred Complainant to her supervisor, Mr. Baldwin because "I had never had this situation in front of me before."[3]

Clearly during his initial inquiry, Complainant spoke to Ms. Trifoli in general, hypothetical terms; Complainant did not identify the specific property from which he wished to transfer capacity; he did not identify the specific property to which he wished to transfer capacity; he neither requested nor obtained anything in writing to memorialize the alleged agreement; he did not inquire as to the existence of any restrictions on his ability to transfer taps; and he did not tell Ms. Trifoli that he intended to purchase property and then transfer the service connections from those properties. Complainant failed to disclose that he intended to purchase property with existing sewer flows and transfer such capacity to undeveloped land he had acquired. There was also no discussion about the amount of capacity he wished to have transferred. Complainant supplied none of these details during his second conversation with Ms. Trifoli, even though by that time he had purchased one lot and the second lot was under contract.

Complainant is not an unsophisticated land owner. He has developed land in North Carolina for over 20 years and has lived in the area served by Respondent (and its predecessor) for nearly 8 years.[4] He was fully aware of the problems with sewer capacity in the area of North Topsail Island; yet when he inquired of Ms. Trifoli, he failed to disclose details critical to the success of his real estate venture. On these facts, Commission concludes that there was no meeting of the minds, and therefore no enforceable agreement that Complainant would be permitted to transfer sewer connections from the two properties he owns in Sneads Ferry to the properties he owns on North Topsail Island.

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[1] Transcript of Formal Hearing, W-1143, Sub 8, June 28, 2007, at 40.
[2] *Id.*
[3] *Id.* at 81.
[4] *Id.* at 27.

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Even assuming that an agreement existed, the Commission does not believe that Complainant has shown that Ms. Trifoli was authorized to bind Respondent. Under principles of agency law, two factors are essential to establish an agency relationship: First, the agent must be authorized to act for the principal; and second, the principal must exercise control over the agent.[1]

Without question, Ms. Trifoli, in her capacity as Respondent's customer service representative, acted as Respondent's agent. Respondent employs Ms. Trifoli in a position which gives her significant exposure to the general public. She communicates with the public and Respondent's customers. In doing so, she implements policies Respondent has adopted and conveys Respondent's efforts to provide sewer service to the area. The Respondent provides direction on what Ms. Trifoli can and cannot share with the public.

However, finding that Ms. Trifoli was Respondent's agent does not end the inquiry. A principal is bound by the acts of its agent acting within the scope of his authority, either express or apparent.[2] Apparent authority is "that authority which the principal has held the agent out as possessing or which he has permitted the agent to represent that he possesses."[3] The scope of an agent's apparent authority is determined not by the agent's own representations, but by the manifestations of authority which the principal accords to him.[4] It must be shown that a third party was reasonable in believing that the principal had conferred authority to the agent to act on its behalf.[5] If the agent is not acting within the apparent authority, the principal is not bound.[6]

The Complainant has not shown that Respondent has provided Ms. Trifoli authority to enter into an alleged agreement to transfer the sewer connections at issue. Complainant relies on the fact that Ms. Trifoli was the only individual in the office when he visited and provided him with information regarding the allocation list. The Commission does not believe that Respondent can be considered liable for Ms. Trifoli's statement simply because she is its employee and the only person Complainant spoke to when he visited Respondent's office. Her employment as Respondent's customer service representative does not automatically mean that Respondent will be liable for any statement that Ms. Trifoli made to him.[7] As stated above, the scope of an

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[1] Convergent Acquisitions and Development, Inc. v. Credent Real Estate, Inc. 2007 WL 2137829 (W.D.N.C.) (*citing* Crist v. Crist, 145 N.C. App. 418, 425, 550 S.E.2d 260, 266 (2001) (*quoting* Johnson v. Amethyst Corp., 120 N.C. App. 529, 532-33, 463 S.E. 2d 397, 400 (1995); Accord Van'd Rood v. County of Santa Clara, 113 Cal. App. 4th 549, 571, 6 Cal. Rptr. 3d 746, 764 (2003).

[2] Hudson v. Jim Simmons Pontiac-Buick, 94 N.C. App. 563, 380 S.E.2d 612 (*citing* Morpul Research Corp. v. Hardware, Co. 263 N.C. 718, 140 S.E.2d 416 (1965)).

[3] Capital Funds, Inc. v. Royal Indemnity Company, 119 N.C. App. 351, 458 S.E.2d 741 (1995) (*citing* Investors Title Ins. Co. v. Herzig, 320 N.C. 770, 360 S.E.2d 786, 788 (1987) (*citing* Zimmerman v. Hogg & Allen, 286 N.C. 24, 209 S.E.2d 795 (1994). *See also* Bell Atlantic Tricon Leasing Corp. v. DRR, Inc. 114 N.C. App. 771, 443 S.E.2d 374 (1994).

[4] *Jim Simmons Pontiac-Buick*, 94 N.C. App. 563 (citing Restatement (Second) of Agency sec. 27 (1958)).

[5] *Royal Indemnity Company*, 119 N.C. App. 351.

[6] Elliott v. Duke University, 66 N.C. App. 590, 311 S.E.2d 632 (*citing* Zimmerman v. Hogg & Allen, 286 N.C. 24, 209 S.E.2d 795 (1974)).

[7] *See* Branch v. High Rock Realty, Inc. 151 N.C. App. 244, 250, 565 S.E.2d 248, 253 (2002) (*emphasis added*) (holding that a real estate agency was not liable to plaintiff for promises made by its former real estate agent, even though such promises were made while the agent was still employed by agency).

agent's apparent authority is determined not by the agent's own representations, but by the manifestations of authority which the principal accords to her.

The Complainant failed to present evidence that Ms. Trifoli either made policy changes or undertook actions constituting executive decisions. Moreover, there was no evidence that Ms. Trifoli did more than act as an administrative staff person for the Respondent. Her creation of the allocation list does not mean that the Respondent granted her authority to bind it into agreements or to deviate from its traditional or longstanding policies and procedures. As Ms. Trifoli stated in her testimony, no one directed her to keep a list; she did it as a convenience because so many people were inquiring about securing sewer service. The list which she developed and maintained was to help her keep track of the people who wanted capacity. It made it easy for the Respondent and Ms. Trifoli, who had to field the calls regarding the availability of capacity.

Because there has been nothing presented in the record to support the finding that the Respondent had granted extensive responsibilities to Ms. Trifoli, the Commission does not believe a reasonable person would believe that she could do more than what was expected as a customer service representative.

Finally, the Commission notes that there was also no evidence in the record that the Respondent ratified Ms. Trifoli's statement to the Complainant. As applied to agency law, "ratification" is an affirmance by the principal of a prior act which did not bind him but which was done or professed to be done on his account, where by the act is given some effect as if originally authorized.[1] In fact as soon as Complainant revealed his intentions, Respondent informed him that it would not be able to facilitate the transfers that he was seeking because the transfers were not within the parameters of its transfer policy.

Based on the foregoing, the Commission does not believe Ms. Trifoli's statement in response to Complainant's general inquiry constituted a legally binding agreement and that her statement did not bind the Respondent to permit the transfers that the Complainant seeks. Therefore, Respondent's refusal to permit Complainant to transfer the sewer connections serving his Sneads Ferry properties to undeveloped property on North Topsail Island was not unreasonable on the facts of this case.

Respondent's transfer policy is not unreasonable and discriminatory as it applies to the Complainant.

The Complainant also asserts that Respondent has applied its transfer policy in an unreasonable and discriminatory manner in violation of G.S. 62-140(a). He alleges that Respondent has permitted other similarly situated property owners to freely transfer sewer connections from one property to another. Further, he contends that because his requested transfer would not "burden" the overall sewer system, he should be entitled to relief under the Commission's decision in Docket No. W-1143, Sub 5[2].

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1 Jones v. Bank of Chapel Hill, 214 N.C. 794, 1 S.E.2d 135 (1939).
2 Richard Twiford, v. North Topsail Utilities, Inc., Docket No. W-1143, Sub 5 (2006).

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G.S. 62-140(a) provides in pertinent part, "[n]o public utility shall, as to rates or services, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage" or establish or maintain any unreasonable difference as to rates or services as between localities or as between classes of service." In essence, G.S. 62-140 prohibits materially different treatment of similarly-situated customers by North Carolina public utilities.

Complainant asserts that Respondent allowed several other similarly situated customers to transfer capacity under its transfer policy. Specifically, Complainant argued that Mr. Mark Evans, a developer, was given preferential treatment and received sewer service in violation of Respondent's first-come, first-served policy. The undisputed evidence showed that Mr. Evans had entered into an agreement in June 2002, for 167 sewer taps, at a time when sufficient sewer capacity existed on the system and <u>before</u> the waiting list was created in March 2003.[1] Mr. Evans' agreement with the Respondent also provided a source of funds for the Respondent to draw upon to fund necessary improvements to the sewer system.[2] Clearly, the Complainant's hypothetical query to Ms. Trifoli was not substantially similarly to Respondent's contractual agreement with Mr. Evans.

Complainant also claimed that several others were freely allowed to transfer sewer service between properties they owned. He sought to establish his claim through the use of Respondent's business records which were admitted into evidence at his request and without objection. The evidence showed that the transfers at issue were either from one undeveloped lot to another where sewer service had not commenced and no tap had been installed or the original lot had been condemned as unbuildable or uninhabitable. Under these conditions, the several property owners to which Complainant referred (Janice Forster, Robert and Barbara Briggs and M&T General Partnership and Twiford) were permitted to transfer their sewer connections from their initial property to another property they owned.[3]

The Complainant also contends that he is entitled to transfer the existing Sneads Ferry service connections to his undeveloped beach property pursuant to the Commission's decision in Docket No. W-1143, Sub 5. The Commission does not find its decision in that case controlling. At issue in Docket No. W-1143, Sub 5, was the reasonableness of Respondent's "eight tap" policy as applied to Complainant Twiford. Respondent implemented an "eight tap" policy after it determined that the newly-released additional sewer capacity was still insufficient to serve all who applied for sewer service. The purpose of the policy is to ensure that all of the newly-available sewer capacity would be not consumed by developers, leaving none for individual homeowners.[4] After consulting with the Public Staff, Respondent implemented a policy that limited the number of taps that a developer could obtain to eight to more equitably allocate the newly-released capacity.[5] The "eight tap" policy became effective in March 2005.

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[1] Transcript at 68.
[2] *Id.*
[3] *Id.* at 84-90.
[4] *Twiford*, W-1143, Sub 5 (2006).
[5] *Id.*

The dispute in that case revolved around whether two sewer connections which Complainant Twiford obtained and paid for before the "eight tap" policy was implemented were appropriately deducted from the "eight tap" maximum. The two taps were used to provide service to Complainant's properties in Sea Dragon which had been destroyed by Hurricane Fran. After the property was destroyed, Respondent permitted Complainant to transfer the two Sea Dragon taps or connections to other habitable property owned by Complainant, but deducted those two taps from the eight pre-paid taps allocated to developers.[1] The Commission was called upon to decide whether, under the facts of that case, Respondent's deduction of the two taps was reasonable. For purposes of assessing the reasonableness of Respondent's "eight tap" policy and whether its application to Complainant Twiford furthered the intent of the policy, the Commission drew a distinction between pre-paid taps for a future physical connection and taps where a previous connection to the system already existed.[2] The Commission noted that the two connections at issue were not pre-paid taps; they actually represented pre-existing flows rather than flows that could be served for the first time as the result of the availability of new capacity.[3] The Commission concluded that because the two connections that Complainant had transferred were not pre-paid taps and did not impose any new burden on the system, deducting them from the number otherwise available to Complainant did not constitute a reasonable application of an otherwise non-discriminatory policy.[4]

In this docket, the Complainant asserts that Respondent's transfer policy is unreasonable. However, the Commission recognizes that there is a need for such a policy given the history of the system and the need for service in the area. That history is set forth in the Commission Order Granting Complaint in Part in Docket No. W-1143, Sub 5, issued April 3, 2006, and incorporated herein by reference. The transfer policy has been in effect for years. According to Respondent, the policy allows lot owners to transfer sewer capacity between two undeveloped lots where the owner owns both lots. It was designed to permit undeveloped lot owners to transfer capacity that has not already been assigned to a specific lot. In exceptional cases, the policy permits lot owners with allocated capacity or a service connection to utilize that connection in the event that use at the original location becomes non-viable. This means that customers will not be harmed because they have allocated capacity at a location but are unable to use it because of problems with the property.

The Complainant in this case attempted to advance his position on Respondent's waiting list for sewer allocation. However, the Commission believes that allowing the Complainant, developers and others to circumvent the waiting list by going out and purchasing lots with existing sewer service and seeking to have the capacity transferred would set a dangerous precedent and is not sound public policy. It places the individuals who have waited patiently for capacity at a disadvantage and might jeopardize the stability of service and the viability of the sewer system. Allowing transfers of the sort requested by Complainant would place a potentially crippling impact on the system if a strict gallon-to-gallon transfer of capacity is not enforced. Trades of property for property that might involve greater flow capacity would certainly place undue burdens on an already stressed system.

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[1] *Id.*
[2] *Id.*
[3] *Id.*
[4] *Id.*

In addition, the possibility and impact of imbalanced transfers is greater in light the Division of Water Quality's new rules that consider each "habitable space" within a property to constitute a bedroom for purposes of calculating sewer capacity requirements.[1] The Commission concludes that the public interest is not served by putting Respondent in the position of having to monitor and enforce development to this extent.

After careful consideration of the facts of this case and the applicable law, the Commission concludes that Complainant has not shown that the Respondent applied its transfer policy in an unreasonable and discriminatory manner in violation of G.S. 62-140(a).

Complainant is not entitled to the relief of specific performance under the doctrine of equitable estoppel.

Complainant's final argument is that he is entitled to relief because he relied upon Trifoli's representations and purchased the properties in Sneads Ferry. The Commission therefore considered whether the Complainant should be required to transfer the sewer capacity from the Complainant's Sneads Ferry properties under the theory of equitable estoppel.

Based on all the evidence of the record, the Commission concludes that the doctrine of equitable estoppel should not be applied in this case. The doctrine of equitable estoppel applies when any one by his acts, representation, or admissions, or by his silence when he ought to speak out, intentionally or through culpable negligence induces another to believe certain facts exists, and such other rightfully relies and acts on such belief, so that he will be prejudiced if the former is permitted to deny the existence of such facts.[2] Under the doctrine of equitable estoppel, the party whose words or conduct induced another's detrimental reliance may be estopped to deny the truth of his earlier representation in the interests of fairness to the other party.[3] Although there need not be actual fraud, bad faith, or an intent to mislead for the doctrine to apply,[4] the Court must consider the conduct of both parties.[5]

The application of the doctrine of equitable estoppel presupposes the existence of several important factors; First, there must be some definite and intentional or negligent representation. That representation must induce another to believe that certain facts exist. Further, the representation must have lead one of the parties to rely on it to his detriment.[6]

The Commission has previously concluded that Respondent was not bound by Ms. Trifoli's statement such that it was required to transfer sewer service from Complainant's Sneads Ferry properties to his North Topsail properties. In addition, in considering the evidence relating to the conduct of the parties in the instant case, the Commission is not persuaded that Ms. Trifoli's response to Complainant's hypothetical question induced Complainant to purchase the

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[1] *See* 15A North Carolina Administrative Code 02T.0114(e)(2).

[2] Whitacre Partnership v. Biosignia, Inc., 358 N.C. 1, 591 S.E.2d 870 (2004).

[3] Thompson v. Soles, 299 N.C. 484, 263 S.E.2d 599 (1980) (*citing* McNinch v. American Trust Co., 183 N.C. 33, 110 S.E. 663 (1922).

[4] White v. Consolidated Planning, 166 N.C. App. 283, 603 S.E.2d 147 (2004) (*citing* Duke University v. Stainback, 320 N.C. 337, 357 S.E.2d 690 (1987).

[5] Whitacre Partnership v. Biosignia, Inc., 358 N.C. 1.

[6] Thompson v. Soles, at 487.

Sneads Ferry properties. Complainant visited Respondent's office several times to inquire about the availability of sewer service. On one of those occasions, he inquired about the possibility of transferring taps from other properties he owned. However, the general, non-specific nature of his question and Ms. Trifoli's response, without more, simply does not support a finding that there was a meeting of the minds. Moreover, the evidence does not support an inference that Ms. Trifoli was intentional or negligence in responding to Complainant's hypothetical question. Finally, the Commission concludes that Complainant's alleged reliance on Ms. Trifoi's response was unreasonable, given his knowledge of development and the availability of sewer capacity in the area. The Complainant was a developer in the area that had been his home for many years; he knew that there was very limited sewer capacity. Prior to his approaching Ms. Trifoli with his general inquiry, he testified that he had undertaken other efforts to obtain sewer service to his North Topsail properties. In addition to having a soil scientist test the property for viability of a septic system, Complainant discussed with Mark Evans the possibility of obtaining some of the capacity that had been allotted to him.[1] Complainant knew that he was number 119 on the list of persons requesting sewer capacity and set out to find a way to move himself in the front of the line of developers and individuals already on the list.

Complainant's final contention is that he relied upon Ms. Trifoli's representation that he could transfer sewer capacity and incurred considerable expense in purchasing the Sneads Ferry properties. In evaluating Complainant's claim of detrimental reliance, the Commission notes that he purchased the North Topsail Beach property without any assurance that he could obtain the requisite sewer capacity to make the property attractive to a builder. Complaint purchased the Sneads Ferry property without fully investigating his options and without disclosing facts critical to the success of his business plan. Nothing prohibits Complainant from moving the mobile homes to a mobile home park that he owns and holding the lots as he originally intended or from reselling the single-wide mobile home lots in Sneads Ferry. Given the options available to Complainant, the Commission is not convinced that Complainant has suffered financial harm.

The doctrine of estoppel rests upon principles of equity and is designed to aid the law in the administration of justice when without its intervention injustice would result.[2] The Commission is not unsympathetic to the situation in which Complainant finds himself. However, after reviewing the conduct of both parties, the Commission does not find that Ms. Trifoli was culpably negligent in responding to Complainant's general inquiry about transferring connections, or that she misrepresented the manner in which he could receive sewer capacity earlier than he was entitled to under Respondent's transfer policy.

CONCLUSION

Complainant has not shown that Respondent agreed to transfer sewer capacity from his Sneads Ferry properties to undeveloped property he owns on North Topsail Beach. Moreover, the Commission has been presented with no evidence tending to show that Respondent failed to uniformly and consistently apply its sewer capacity transfer policy or that Respondent acted in a discriminatory and unreasonable manner in denying the Complainant's request. Finally, the Commission concludes that the evidence does not support Complainant's contention that

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1 Transcript at 68.

2 *Thompson v. Soles*, at 486 (*See also* Hawkins v. M. & J. Finance Corporation, 238 N.C. 174, 77 S.E.2d 669 (1953)).

Respondent should be estopped from denying him the right to effect the capacity transfer he seeks. As a result, the Commission hereby denies the Complainant the relief requested in this complaint docket.

IT IS, THEREFORE ORDERED that the Complaint is hereby dismissed.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of November, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Ah112807.02

Commissioner William Culpepper, III, dissents from this decision.

DOCKET NO. W-1143, SUB 8

COMMISSIONER WILLIAM T. CULPEPPER, III, DISSENTING: I respectfully dissent. While I do concur with the majority's conclusion that the Complainant has not shown that the Respondent applied its sewer tap transfer policy in a manner that discriminated against Complainant in violation of G.S. 62-140(a), I am of the opinion that the hearing evidence clearly shows that Respondent's agent, Lillian Trifoli, had (at a minimum) the apparent authority to bind her principal and that Complainant is entitled to have the sewer capacity assigned to his Sneads Ferry lots transferred to his North Topsail Island property under the doctrine of equitable estoppel. To the extent that the Complainant's pleadings in this docket fail to state a claim against the Respondent based upon the doctrine of equitable estoppel, they have been amended by evidence introduced at the hearing received without objection. G.S. 1A-1, Rule 15 (b); Mangum v. Surles, 281 N.C. 91 (1972). The Commission's jurisdiction over this claim is pursuant to G.S. 62-73.

The majority's decision rests, in part, on the premise that Respondent's agent, Lillian Trifoli, lacked authority, both actual and apparent, to make binding representations on behalf of her principal with respect to the transfer of sewer taps from Sneads Ferry properties to properties located on North Topsail Island. In my opinion the evidence overwhelmingly indicates to the contrary.

Mr. Gregory's first contact with North Topsail Utilities, Inc. was in 2003. The home he and his wife were living in on North Topsail Island had a septic tank and he went in to the utility's office to determine if they had any sewer availability. He was advised at that time they did not. Towards the end of 2003 he dropped by again to see "if there were any changes, any sewer availability." (Transcript at 28).

When Gregory went to the office of North Topsail Utilities, he spoke to Lillian Trifoli. Gregory came to visit the utility's office eight to ten times. During all of these visits he dealt, for the most part, with Lillian Trifoli. On one visit he met and had some dealings with Eddie Baldwin. There was never anyone else in the utility's office other than Lillian Trifoli and "the one time Eddie Baldwin" who was a representative for North Topsail Utilities that dealt with Gregory. (Transcript at 29).

In March of 2004 Gregory went to the North Topsail Utilities office for the purpose of inquiring about the availability of sewer connections for two lots he had purchased from Onslow County located in the Topsail Villas Subdivision. (Transcript at 30-32). At that time he spoke to Lillian Trifoli who informed him that "there were no taps available," but that there was going to be an allocation in six to eight months. (Transcript at 32). Subsequently in 2004 Gregory would periodically return to the North Topsail Utilities office to check on sewer availability with Ms. Trifoli who would tell him that there was no progress in the allocations. (Transcript at 33). Sometime in 2004 Ms. Trifoli informed Gregory that she was keeping a list of people that were applying for taps. Gregory asked to be put on that list and was assigned number 119 by Ms. Trifoli. (Transcript at 33-34). During 2004 Gregory never spoke to anyone other than Ms. Trifoli during his visits to the North Topsail Utilities office. (Transcript at 34-35).

In November of 2005 Gregory passed by some properties in Sneads Ferry with a realtor sign on one of them upon which was located a singlewide mobile home with a Simplex pump in the yard (Transcript at 36), indicating to Gregory that there was a connection to the North Topsail Utilities sewer facility. (Transcript at 37). Upon discovering this property with the Simplex pump, Gregory went to see Ms. Trifoli and asked her "if I had properties in Sneads Ferry with taps could I transfer those taps to North Topsail Beach where we had other properties." Ms. Trifoli's reply was "yes, I see no problem with that as long as one person owns both properties." She did not say anything else at that time. (Transcript at 40). She did not mention any kind of restrictions or modifications to that policy. (Transcript at 40-41). She did not provide Gregory with anything in writing that described the policy about transfers. She did not say that she needed to speak to her superior to get clearance for the permission to do the transfer. At that time there was no one else there. She didn't tell Gregory that she needed to go to another level of authority and she did not ask him to put his request in writing. (Transcript at 41).

After this conversation with Ms. Trifoli, Gregory purchased the Sneads Ferry property with the Simplex pump that he had previously identified for $48,000 (Transcript at 41) and thereafter signed a contract for a second property because he "...was wanting two taps for the big lot on North Topsail so that there could be a duplex built." The purchase price for the second property was $35,000. These two properties in Sneads Ferry are small lots along Clay Hill Road that have singlewide mobile homes on them with the Simplex pump alarm system showing in the yard. (Transcript at 42).

After Gregory signed the contract for the second property, he went back to North Topsail Utilities and told Ms. Trifoli that he had purchased one lot and had a contract on another and wanted to know how to go about the transfer of sewer capacity. (Transcript at 42-43). At this point he was referred by Ms. Trifoli to Eddie Baldwin. Up until this point he had never seen or spoken to Mr. Baldwin. Prior to this point Ms. Trifoli had never referred Gregory to Mr. Baldwin. (Transcript at 43). Mr. Baldwin advised Gregory that the proposed tap transfer would not be allowed. (Transcript at 44). This denial was later reiterated by utility officials Jim Highley and Richard Durham notwithstanding Ms. Trifoli's previous statement that such a transfer would be permitted. Mr. Durham confirmed that Ms. Trifoli had in fact made the statement to Gregory that he could transfer taps but that in doing so she "did not understand the circumstances at that time." (Transcript at 45-47).

On a typical day in the North Topsail community, Ms. Trifoli is the person that talks to the public on behalf of North Topsail Utilities. (Transcript at 75). While Mr. Baldwin also has an office there, "he has other areas he has to cover, so he's not there..." (Transcript at 75). When Ms. Trifoli told Gregory that taps in Sneads Ferry could be transferred to North Topsail Beach property provided the same owner owns both properties (Transcript at 76), she never told him that there were any restrictions on this transfer policy. (Transcript at 78).

In addition to all of the foregoing testimony, I find the following exchange between Complainant's attorney and Ms. Trifoli particularly compelling as it relates to her authority as Respondent's agent:

Q. And you're the voice of North Topsail (Utilities) to Mr. Gregory as you are to everyone else in North Topsail (beach) that makes inquires about sewer connection ..

A. Right.
Q. .. isn't that true?

A. Yes, sir. (Transcript at 78).

I also find it noteworthy that the evidence clearly shows that with respect to tap transfers that were allowed by Respondent, it was Ms. Trifoli who filled out the transfer permits and otherwise acted to effect the transfers. (See Transcript at 83-84; 88-89; 92-92).

All of the foregoing leads me to the inescapable conclusion that Ms. Trifoli, as agent for Respondent, was clearly vested with apparent, if not actual, authority to bind her principal regarding representations made by her to the Complainant pertaining to the transfer of sewer capacity on Respondent's wastewater facilities.

There is no doubt that Ms. Trifoli did state to the Complainant that the Respondent would permit a transfer of sewer taps from Sneads Ferry properties to North Topsail Island properties and that, in so stating, she failed to communicate any qualifications or exceptions for improved properties with sewer service already in place. Having reached the conclusion that Ms. Trifoli had the authority (apparent at a minimum, if not actual) to bind the Respondent with her statement, inquiry now shifts to whether or not Respondent should be estopped from denying the transfer of Complainant's tap capacities.

The elements of equitable estoppel are outlined in <u>Hawkins v. Finance Corp.</u>, 238 N.C.174, 177-178 (1953), which case is more recently cited in <u>Meacham v. Board of Education</u>, 47 N.C. App. 271, 277-278 (1980), <u>appeal after remand</u>, 59 A.C. App. 381, 386 (1982), <u>disc review denied</u>, 307 N.C. 577 (1983).

Stated in a manner that I believe to be most relevant to this case, the essential elements of an equitable estoppel as related to the party estopped are: (1) Conduct ... at least, which is reasonably calculated to convey the impression that the facts are otherwise than, and inconsistent with, those which the party afterwards attempts to assert, Meacham, 59 N.C. App. at 386; (2) ...conduct which at least is calculated to induce a reasonably prudent person to believe such conduct was intended or expected to be relied and acted upon; (3) knowledge, actual or constructive, of the real facts. As related to the party claiming the estoppel, they are: (1) lack of knowledge and means of knowledge of the truth as to the facts in question; (2) reliance upon the conduct of the party sought to be estopped; and (3) action based thereon of such a character as to change his position prejudicially. Hawkins, supra., at 177-178.

With respect to the elements related to the Respondent as the party to be estopped: (1) Ms. Trifoli's conduct as Respondent's agent in making her unqualified, unconditional statement to Complainant that, if he had properties in Sneads Ferry with taps, he could transfer those taps to North Topsail beach where he had other properties so long as the same person owns both properties is clearly inconsistent with the position that Respondent now asserts in denying the transfer.

(2) Because of Ms. Trifoli's self-proclaimed position as Respondent's voice to everyone in North Topsail beach that makes inquiries about sewer connections, a position that has not otherwise been refuted by Respondent, and the numerous inquiries made of her by Gregory pertaining to acquiring sewer capacity for his North Topsail properties, it is entirely reasonable and prudent for both Ms. Trifoli and Gregory to believe that he could rely on her representations and act thereon if necessary to acquire sewer capacity for his beach properties. Moreover, it is entirely reasonable under the circumstances that Ms. Trifoli's statement was calculated to induce Gregory to purchase the properties that he acquired. Gregory was obviously highly motivated to obtain sewer capacity for his beach lots. Had he already owned properties in Sneads Ferry at the time of his conversation with Ms. Trifoli, the conversation would not have stopped where it did. He would have identified his Sneads Ferry properties on the spot and made further inquiry then as to how to effect the transfer. At the time Gregory walked away with Ms. Trifoli's unqualified representation in hand, it should then have been reasonably clear to her that there existed a distinct possibility that Gregory did not then own, and would act on her representation to purchase, Sneads Ferry properties.

(3) At the time she made the subject representation to Gregory, Ms. Trifoli had either actual or constructive knowledge of the Respondent's transfer policy which, in fact, was not unconditional and did not allow for the transfer of already connected capacity to unimproved lots.

With respect to the elements related to the Complainant as the party claiming the estoppel: (1) Gregory obviously did not have knowledge of the full extent of the Respondent's sewer capacity transfer policy. It is unreasonable to believe that he would have purchased the Sneads Ferry properties had he known that they would not qualify for a capacity transfer. Moreover, in light of Ms. Trifoli's unqualified and absolute statement to Gregory pertaining to transfer of sewer capacity from Sneads Ferry properties to North Topsail beach, I do not find the requirement of "lack of ... the means of knowledge of the truth as to the facts in question" to preclude Complainant's assertion of estoppel against Respondent. I find Meacham, supra. to be instructive in this regard. In Meacham the plaintiff school teacher, experiencing severe medical problems, sought advice from her school board's agents regarding her options and was recommended disability retirement, being assured that "the retirement aspect was just a formality because the state regulations provide that the benefits stop automatically when one returns to work." Id. 59 N.C. App. at 382. It was only after the plaintiff, her medical problems resolved, later made inquiry about what steps she needed to take about returning to work, that she was for the first time informed that disability retirement was tantamount to a resignation. As to the issue of plaintiff's lack of knowledge and means of knowledge, the court stated, "we do not agree that plaintiff was required to make extensive inquiry for herself after being advised the 'the retirement aspect was just a formality.'" Id. at 383 citing 49 N.C. App. at 279. Following Meacham, I do not believe Complainant in this docket was required to make extensive inquiry for himself after receiving unqualified advice from Respondent that Sneads Ferry sewer capacities could be transferred to North Topsail beach properties.

(2) The evidence is clear that Gregory relied upon Ms. Trifoli's representation in purchasing the Sneads Ferry properties, which he would not have done had he known the real facts. His sole purpose in buying the Sneads Ferry properties was to transfer the sewer taps to his North Topsail beach property. (Transcript at 47).

(3) Gregory's expenditure of $83,000 to purchase properties that he would not have purchased but for Respondent's representation clearly constitutes action based thereon as to change his position prejudicially. I am not persuaded by the majority's opinion that Complainant has not been prejudiced, because he can make other uses of the purchased Sneads Ferry properties. The more important point in this regard is that Gregory is unable to make use of the properties for the purpose for which they were purchased, which purchase would not have taken place but for Respondent's false representation that it now seeks to avoid.

I am mindful of Respondent's contention that the decision I would reach in this case would cause it some financial loss. Hearing testimony indicates that the company spent $3,000 per lot installing the Simplex pumps on the two Sneads Ferry properties purchased by Gregory, which costs have been only partially offset by two tap fees of $2,000 each which have already been paid. It is not known for sure how long the subject properties have been serviced by the utility (Transcript at 97-98), so the undepreciated value of these assets to the utility, if any, is also unknown. In any event, application of the so-called "he-who" rule[1] dictates that it is the Respondent who must bear any loss in this regard. "The rule rests upon the broad equitable doctrine that where one of two equally innocent persons must suffer, he who has so conducted himself, by his negligence or otherwise, as to occasion the loss, must sustain it." (citations omitted). Hawkins, supra. at 179.

I would not have my decision constitute any precedent that requires an amendment to the Respondent's sewer capacity transfer policy dictating that Respondent would be bound in the future to permit the type of transfer that I believe should be allowed under the unique circumstances of this docket. Respondent can easily avoid a replication of what has occurred here by simply correctly articulating the details of its transfer policy to any future would-be customers.

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[1] A term coined by former Wake Forest University law school Professor Robert E. Lee and used during his lectures on his publication, Cases On Personal Property, Fall of 1970.

Furthermore, my decision would not create any new burden on Respondent's sewer system which remains under a moratorium. Mr. Gregory's request is to transfer the 720 g.p.d. capacity currently assigned to his two Sneads Ferry properties over to his North Topsail beach property. He does not request, nor would I vote to permit, any additional capacity for his beach property beyond that already assigned to the 271 and 273 Clay Hill Road, Sneads Ferry properties.

In conclusion, I am of the opinion that the facts presented in this docket, together with the law applicable thereto as more fully set forth above, dictates that the Commission should issue an order requiring the Respondent to transfer the 720 g.p.d. sewer capacity allotted on its system to the properties located at 271 and 273 Clay Hill Road, Sneads Ferry to Complainant's property located on New River Inlet Road on North Topsail Island designated as Tax Parcel 774-88. I am mindful of Complainant's desire to have the option of assigning half of the total 720 g.p.d. capacity to his other North Topsail lot designated as Tax Parcel 774-95. It is my understanding that this could occur at Complainant's option under Respondent's existing transfer policy, since both lots are currently unimproved.

\s\ William T. Culpepper, III
Commissioner William T. Culpepper, III

DOCKET NO. W-354, SUB 297

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 Increase Rates for Water and Sewer Utility Service in All of Its Service Areas in North Carolina	ORDER GRANTING PARTIAL RATE INCREASE AND REQUIRING CUSTOMER NOTICE

HEARD IN: Watauga County Courthouse, 842 West King Street, Boone, North Carolina on Tuesday, January 23, 2007, at 7:00 p.m.

Public Works Building, 161 South Charlotte Street, Asheville, North Carolina on Wednesday, January 24, 2007, at 7:00 p.m.

Public Library of Charlotte and Mecklenburg County, 310 North Tryon Street, Charlotte, North Carolina on Thursday, January 25, 2007 at 7:00 p.m.

Municipal Building, 102 Town Hall Drive, Kill Devil Hills, North Carolina on Monday, February 5, 2007, at 7:00 p.m.

Onslow County Courthouse, E.W. Summersill Building, 109 Old Bridge Street, Jacksonville, North Carolina on Tuesday, February 6, 2007, at 7:00 p.m.

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, February 7, 2007, at 7:00 p.m. and Tuesday, April 17, 2007, at 9:30 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Commissioner Howard N. Lee, and Commissioner William T. Culpepper, III.

APPEARANCES: For Carolina Water Service, Inc. of North Carolina:

Christopher J. Ayers, Hunton & Williams LLP, P.O. Box 109, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Gina C. Holt and Tab C. Hunter, Staff Attorneys, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

WATER AND SEWER – RATE INCREASE

BY THE COMMISSION: On September 29, 2006, Carolina Water Service, Inc, of North Carolina (Carolina Water, Applicant, or Company) filed a letter notifying the Commission of its intent to file a general rate case as required by Commission Rule R1-17(a).

On November 1, 2006, Carolina Water[1] filed an application with the Commission for authority to increase its rates for water and sewer utility service in all its service areas in North Carolina.

On November 3, 2006, the Applicant filed a letter amending its Application to reflect the effective date for proposed rates as December 1, 2006.

On November 8, 2006, November 22, 2006, and November 27, 2006, the Company filed amendments to its Application.

On November 28, 2006, the Commission issued an Order Establishing General Rate Case and Suspending Rates.

On December 20, 2006, the Commission issued an Order Scheduling Hearings and Requiring Customer Notice. Customer hearings were scheduled to be held in Boone, Asheville, Charlotte, Kill Devil Hills, Jacksonville, and Raleigh, North Carolina, and an evidentiary hearing was scheduled in Raleigh for April 17 – 19, 2007.

On December 21, 2006, the Commission revised its December 20, 2006 Order to reflect only the start date of the evidentiary hearing, April 17, 2007.

On January 17, 2007, the Applicant filed an amendment to its Application.

On January 25, 2007, Carolina Water filed a Certificate of Service indicating that the public notice had been provided in accordance with the Commission's December 20, 2006 Order.

Public hearings were held as scheduled. The following public witnesses testified at the public hearings held in this proceeding:

January 23 – Boone	John Rainey and Alex Popper
January 24 – Asheville	Lee Luebbe, James Hemphill, Jimmy Harley, Burris Ramey, Richard Savard, James T. Tanner, Jr., and Tammy Leino
January 25 – Charlotte	Steven Smith, Joseph Constant, and William Boggs
February 5 - Kill Devil Hills	Robert Schultz, Hugh McCain, Karen Galganski, and Sandra Powers
February 6 – Jacksonville	Edwin Snider

[1] Carolina Water is a wholly owned subsidiary of Utilities, Inc. (UI). This rate proceeding also includes two other wholly owned subsidiaries of UI, Riverpointe Utility Corporation and Watauga Vista Water Corporation, which were authorized to be merged into Carolina Water by Commission Order dated January 19, 2007, in Docket Nos. W-962, Sub 3 and W-703, Sub 3. These two companies traditionally have had the same rate structure as Carolina Water.

WATER AND SEWER – RATE INCREASE

February 7 – Raleigh	David Eckel
April 17 – Raleigh	Randy Saunders, Bob Zschoche, Hugh McCain, and Donise Knight

On February 12, 2007, Christopher J. Ayers of the law firm of Hunton & Williams LLP filed a Motion to Withdraw and Appearance of New Attorney.

On February 15, 2007, the Commission issued an Order Allowing Withdrawal and Substitution whereby Edward S. Finley, Jr., was allowed to be withdrawn as counsel in this docket.

Also on February 15, 2007, Carolina Water and the Public Staff filed a Partial Settlement Agreement entered on February 14, 2007, in this proceeding which stipulated to the appropriate capital structure and cost rates on the components of the capital structure and return on rate base.

On February 16, 2007, the Company prefiled the testimony of Lena Georgiev, Senior Regulatory Accountant for Utilities, Inc.

On March 20, 2007, the Public Staff verbally requested an extension of time until March 27, 2007, within which to file its testimony and an extension until April 9, 2007, for Carolina Water to file its rebuttal testimony. On that same date, the Commission issued an Order Granting Extension of Time.

On March 27, 2007, the Public Staff verbally requested an extension until March 29, 2007, within which to file its testimony. On that same date, the Commission issued an Order Granting Extension of Time.

On March 29, 2007, Carolina Water and the Public Staff filed a Joint Stipulation that settled the outstanding issues between the parties related to proposed rates and charges. On that same date, the Public Staff filed the testimony of Jerry H. Tweed, Utilities Engineer, Water Division.

On April 4, 2007, the Commission issued an Order Requiring Reports on Customer Concerns Regarding Quality of Service.

On April 10, 2007, the Company filed a report addressing the service-related complaints expressed at the public hearings. On April 12, 2007, the Public Staff filed a letter stating that Carolina Water's April 10, 2007 Report was acceptable.

On April 16, 2007, Carolina Water and the Public Staff filed an Amended Joint Stipulation.

On April 17, 2007, an evidentiary hearing was held at the North Carolina Utilities Commission hearing room in Raleigh, North Carolina, as scheduled. The Commission received testimony from public witnesses Randy Saunders, Bob Zschoche, Hugh McCain, and Donise Knight.

Public witness Saunders testified on several service-related matters regarding the service in the Village of Whispering Pines. On cross-examination, he opined that the Company was working to correct the issues except for the issue related to the requested continuous upgrades in the system's infrastructure. Public witness Saunders testified that, as a Councilman for the Village of Whispering Pines, the customers would like to see the Company make a steady investment in the current infrastructure serving the customers of the Village of Whispering Pines, as opposed to the present "when you have to do it" basis. In response, Presiding Commissioner Ervin encouraged Mr. Saunders to stay in contact with the Public Staff and to use the Commission's established complaint procedures should the service in the Village of Whispering Pines fall below an acceptable standard.

Public witness Zschoche expressed concern regarding a Notice of Deficiency that Carolina Water received regarding the segment of a dam that it owns located in the Village of Whispering Pines, and he questioned if the resources to fund the required repairs would be obtained from Carolina Water's customers. During cross-examination it became apparent that Carolina Water had contacted the Army Corps of Engineers and had obtained a permit to make the necessary repairs; however, no monies associated with the repair of that dam have been included in this present proceeding.

Public witness McCain had previously provided a statement regarding service in the Monteray Shores community at the February 5, 2007 hearing in Kill Devil Hills, North Carolina, and on April 17, 2007, he provided additional statements, representing all homeowners, regarding, among other things, the building moratorium on sewer connections and the level of the requested rate increase. During cross-examination it became apparent that Carolina Water had recently been issued a final permit from the Department of Water Quality to expand the wastewater treatment plant at Monteray Shores and that the bidding process had begun.

Public witness Knight testified that she did not have a complaint about the service that she has received but that, "my concern here, as far as the rate increase, is if I'm receiving a rate increase, how will that benefit me".

The Applicant presented the direct prefiled testimony of Lena Georgiev. The Public Staff presented the prefiled testimony of Jerry H. Tweed. The Commission also took sworn testimony from Katherine A. Fernald, Water Supervisor, Public Staff Accounting Division, and Richard Durham, North Carolina Regional Director for Carolina Water.

On June 25, 2007, Carolina Water filed a motion requesting authority to implement rates equivalent to the rates included in Appendix A of the Amended Joint Stipulation filed on April 16, 2007, pending issuance of the Commission's final Order in this proceeding.

On the basis of the application, the Partial Settlement Agreement, the Joint Stipulation, the Amended Joint Stipulation, and the other evidence of record, the Commission makes the following

FINDINGS OF FACT

1. Carolina Water is a corporation duly organized under the laws of and authorized to do business in the State of North Carolina. Carolina Water is a franchised public utility providing water and/or sewer utility service to customers in North Carolina.

WATER AND SEWER – RATE INCREASE

2. Carolina Water 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 for its water and sewer operations.

3. The test period appropriate for use in this proceeding is the 12-month period ended June 30, 2006, updated through December 31, 2006.

4. The overall quality of service provided by Carolina Water to its customers is adequate.

5. A total of 21 customers testified at the public hearings in opposition to the proposed rate increase. Of those 21 customers, seven customers from five service areas testified on service-related issues. The water service concerns expressed by these customers included, but were not limited to, the presence of iron and manganese in the water, radiological contamination, the level of chlorine in the water, the hardness of the water, low pressure, discolored water, and air bubbles. Concerns regarding sewer service related primarily to reports of odor from the Cabarrus Woods wastewater treatment plant and a pump station in the Bradford Park service area.

6. Carolina Water filed a report with the Commission addressing the service-related concerns expressed by the customers at the public hearings. Subsequent to the filing of that report, the Public Staff filed a letter indicating that it found Carolina Water's Report to be acceptable. Information provided upon cross-examination of the public witnesses at the April 17, 2007 hearing addressed the concerns expressed by the customers that testified at the evidentiary hearing.

7. Carolina Water's present rates are as follows:

Water Rates and Charges

Monthly Metered Service:

Base Facilities Charges		
A.	Residential Single Family Residence	$ 11.90
B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 11.90
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (as in a condominium complex)	$ 10.90
D.	Commercial and Other (based on meter size):	
	<1" meter	$ 11.90
	1" meter	$ 29.75
	1½" meter	$ 59.50
	2" meter	$ 95.20
	3" meter	$ 178.50
	4" meter	$ 297.50

WATER AND SEWER – RATE INCREASE

6" meter	$ 595.00

Usage Charge:

A.	Treated Water, per 1,000 gallons	$ 3.60
B.	Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.40

Flat Rate Service:

A.	Single Family Residential	$ 25.60
B.	Commercial per single family equivalent (SFE)	$ 25.60

Availability Rates (semiannual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 14.40

Meter Testing Fee:	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charges:

If water service is cut off by utility for good cause	$ 27.00
If water service is disconnected at customer's request	$ 27.00

Management Fee (in the following subdivisions only):

Cambridge	$ 250.00
Windsor Chase	$ 63.00
Wolf Laurel	$ 150.00

Oversizing Fee (in the following subdivision only):

Winghurst	$ 400.00

Meter Fee:

For 5/8" or 3/4" meters	$ 50.00
For meters greater than 3/4"	Actual Cost

Sewer Rates and Charges

Monthly Metered Service: Commercial and Other

A. Base Facility Charge (based on meter size):

WATER AND SEWER – RATE INCREASE

<1" meter	$ 11.70
1" meter	$ 29.25
1½" meter	$ 58.50
2" meter	$ 93.60
3" meter	$ 175.50
4" meter	$ 292.50
6" meter	$ 585.50

B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 5.30
C.	Minimum Monthly Charge	$ 35.50
D.	Sewer customers who do not receive water service from the Company/SFE	$ 35.50

<u>Flat Rate Service</u>: Per Dwelling Unit $ 35.50

<u>Collection Service Only</u>:
(When sewage is collected by utility and transferred to another entity for treatment)

A.	Single Family Residence	$ 12.75
B.	Commercial/SFE	$ 12.75

<u>Mt. Carmel Subdivision Service Area</u> (based on metered water usage):

Monthly Base Facility Charge	$ 5.05
Usage Charge, per 1,000 gallons	$ 4.40

<u>Regalwood and White Oak Estates Subdivision Service Area</u>

Monthly Flat Rate Sewer Service:

Residential Service	$ 35.50
White Oak High School	$1,118.00
Child Castle Daycare	$ 143.00
Pantry	$ 78.00

<u>New Sewer Customer Charge</u>: $ 22.00

<u>Reconnection Charge</u>:

If sewer service is cut off by utility for good cause — Actual Cost

8. Carolina Water requested an increase in its water and sewer rates that would produce the following additional revenues:

Water	$1,797,580
Sewer	$1,312,820

WATER AND SEWER – RATE INCREASE

9. Carolina Water's original cost rate base for its water and sewer operations, respectively, at June 30, 2006, updated to December 31, 2006, is as follows:

Water	$22,086,168
Sewer	$11,857,543

10. Carolina Water had water plant in service of $54,361,700 and sewer plant in service of $40,551,550 at the end of the test year, including pro forma adjustments.

11. The accumulated depreciation at the end of the test year, including pro forma adjustments, was $9,190,810 for water operations and $7,635,399 for sewer operations.

12. The contributions in aid of construction (CIAC) at the end of the test year was $22,310,272 for water operations and $21,435,172 for sewer operations, reduced by accumulated amortization of $3,220,662 for water operations and $3,715,080 for sewer operations.

13. The pro forma plant to be included in the rate base is $1,060,351 for water operations and $149,735 for sewer operations.

14. Carolina Water is entitled to total rate case costs of $284,846, consisting of $500 of filing fees, $19,191 of costs to mail notices, $100,000 of legal fees, $87,300 of Water Service Corporation personnel costs, $10,000 of miscellaneous costs, $8,500 of travel costs, and $59,355 of unamortized costs from the prior rate case. These total rate case costs of $284,846 should be amortized over three years, thereby resulting in an annual rate case expense of $94,949 ($58,080 water operations and $36,869 sewer operations).

15. It is appropriate to calculate regulatory fees using the statutory rate of 0.12%.

16. It is appropriate to calculate gross receipts tax based upon the approved levels of revenues and the statutory rates of 4% for water operations and 6% for sewer operations.

17. It is appropriate to calculate state and federal income taxes based upon the corporate tax rates of 6.9% for state income tax and 34% for federal income tax.

18. Carolina Water's total operating revenue deductions under present rates are:

Water	$7,161,377
Sewer	$5,579,351

19. Carolina Water's present rates produce the following operating revenues:

Water	$8,429,176
Sewer	$6,375,943

20. On February 15, 2007, Carolina Water and the Public Staff entered into a Partial Settlement Agreement establishing the rate of return components to be used in this proceeding. The agreed-upon overall rate of return on rate base was established at 8.23%, which includes a return on common equity component of 10.55%.

WATER AND SEWER – RATE INCREASE

21. Carolina Water and the Public Staff entered into and filed a Joint Stipulation on March 27, 2007. The Joint Stipulation contained rates and charges agreed to by Carolina Water and the Public Staff as well as an agreement to amend such stipulation to include certain rate base projects and salaries adjustments if adequately documented by the Company and provided to the Public Staff by April 12, 2007.

22. Carolina Water and the Public Staff entered into and filed an Amended Joint Stipulation on April 16, 2007. The Amended Joint Stipulation contained the final, adjusted rates and charges agreed to by the Company and the Public Staff.

23. Carolina Water and the Public Staff have agreed that Carolina Water is entitled to changes in rates that will produce the following levels of annual operating revenues:

Water	$9,349,428
Sewer	$6,686,739

24. These stipulated rates will produce increases in revenues as follows:

Water	$920,252
Sewer	$310,796

25. Carolina Water's total operating revenue deductions under the stipulated rates are as follows:

Water	$7,531,736
Sewer	$5,710,863

26. The monthly water and sewer rates, as stipulated to by Carolina Water and the Public Staff, are as follows:

Water Utility Service

Monthly Metered Service:

Base Facilities Charges (zero usage)

A.	Residential Single Family Residence	$ 13.60
B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 13.60
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (as in a condominium complex)	$ 12.45
D.	Commercial and Other (based on meter size):	
	<1" meter	$ 13.60
	1" meter	$ 34.00
	1½" meter	$ 68.00
	2" meter	$108.80

WATER AND SEWER – RATE INCREASE

3" meter	$204.00
4" meter	$340.00
6" meter	$680.00

Usage Charge:

A.	Treated Water/1,000 gallons	$ 4.12
B.	Untreated Water/1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.74

Monthly Flat Rate Service:

A.	Single Family Residential	$ 29.70
B.	Commercial/SFE (single family equivalent)	$ 29.70

Availability Rates (semiannual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 16.50

Meter Testing Fee:	$ 20.00
New Water Customer Charge:	$ 27.00

Reconnection Charges:

If water service is cut off by utility for good cause	$ 27.00
If water service is disconnected at customer's request	$ 27.00

Management Fee (in the following subdivisions only):

Cambridge	$250.00
Windsor Chase	$ 63.00
Wolf Laurel	$150.00

Oversizing Fee (in the following subdivision only):

Winghurst	$400.00

Meter Fee:

For 5/8" or 3/4" meters	$ 50.00
For meters greater than 3/4"	Actual Cost

WATER AND SEWER – RATE INCREASE

Sewer Utility Service

Monthly Metered Service - Commercial and Other Non-Residential Users:

A. Base Facility Charges (based on meter size with zero usage)

5/8" x 3/4" meter	$ 12.50
1" meter	$ 31.25
1½ " meter	$ 62.50
2" meter	$100.00
3" meter	$187.50
4" meter	$312.50
6" meter	$625.00

B. Usage Charge/1,000 gallons (based on metered water usage) — $ 5.60

C. Minimum Monthly Charge — $ 37.25

D. Sewer customers who do not receive water service from the Company per SFE (single family equivalent) — $ 37.25

Monthly Flat Rate Service:

Per Dwelling Unit — $ 37.25

Monthly Collection Service Only:
(when sewage is collected by utility and transferred to another entity for treatment)

A. Single Family Residence — $ 13.50

B. Commercial/SFE — $ 13.50

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge — $ 5.05

Usage Charge/1,000 gallons (based on metered water usage) — $ 4.40

Regalwood and White Oak Estates Subdivision Service Areas:

A. Monthly Flat Rate Sewer Service:

Residential Service	$ 37.25
White Oak High School	$1,175.00
Child Castle Daycare	$ 150.00
Pantry	$ 82.00

B. Minimum Monthly Charge — $ 37.25

New Sewer Customer Charge:	$ 22.00
Reconnection Charges:	
If sewer service is cut off by utility for good cause	Actual Cost
Charges for Processing NSF Checks:	$ 15.00

27. The rates agreed to by Carolina Water and the Public Staff, as provided hereinbefore and included in Appendix A attached hereto, are just and reasonable and should be approved.

28. The Company should revise its calculation of allowance for funds used during construction (AFUDC) as stipulated, in the following manner:

a. All plant modification fees collected during the year should be applied to the project additions accruing AFUDC during the year such that AFUDC should not be calculated on amounts funded by CIAC through plant modification fees.

b. The calculation should be based on the actual costs for the year.

29. The Company should revise its procedures for handling work orders to prevent work order related costs from being booked directly to plant in service, as stipulated.

30. The Company should correct the entry made on its books to remove the amounts refunded from CIAC so that the amounts refunded will be recorded on a system-specific basis, as stipulated.

31. The Company should comply with the Order issued on April 15, 2005, in Docket No. W-354, Sub 266, and will begin recording antenna lease revenues in miscellaneous revenues on Carolina Water's North Carolina books, as stipulated.

32. The Company should begin recording all revenues collected in Mt. Carmel in service revenues on its books, as stipulated.

33. The Amended Joint Stipulation contained the provision that Carolina Water and the Public Staff agreed to waive appeal of a final Order of the Commission incorporating the matters stipulated in the Amended Joint Stipulation.

34. The Amended Joint Stipulation contained the provision that Carolina Water and the Public Staff agreed that none of the positions, treatments, figures, or other matters 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 in issue.

CONCLUSIONS

Based upon the foregoing findings of fact and the entire record in this proceeding, the Commission is of the opinion that the stipulated rates should be approved and the Amended Joint Stipulation, between the Public Staff and Carolina Water, entered and filed on April 16, 2007, which is incorporated by reference herein, should be approved.

In making our decision, the Commission has taken into account the testimony of the public witnesses. By Order issued April 4, 2007, the Commission required the Applicant to file a report addressing the quality of service concerns expressed by the customers at the public hearings and further required that the Public Staff file a response to such report. Additionally, the Commission's April 4, 2007 Order allowed for reply comments by Carolina Water. On April 10, 2007, the Company filed a report addressing the service-related complaints expressed at the public hearings. On April 12, 2007, the Public Staff filed a letter stating that Carolina Water's April 10, 2007 Report was acceptable. No reply comments were filed. The Commission believes that the April 10, 2007 filing by Carolina Water, as well as the information provided upon cross-examination of the public witnesses at the April 17, 2007 hearing, adequately addressed the service-related concerns expressed by all the public witnesses.

With respect to the Company's request to implement the rates included in the April 16, 2007 Amended Joint Stipulation, pending issuance of a final Order in this proceeding, the Commission finds and concludes that the issuance of the present Order renders such request moot.

IT IS THEREFORE, ORDERED as follows:

1. That the Schedule of Rates, attached hereto as Appendix A, is hereby approved and deemed to be filed with the Commission pursuant to G.S. 62-138.

2. That the Schedule of Rates is hereby authorized to become effective for service rendered on and after the issuance date of this Order.

3. That a copy of the Notice to Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all affected customers by the Company in conjunction with the next regularly scheduled billing process.

4. That the Applicant shall file the attached Certificate of Service, properly signed and notarized, no later than 30 days after the issuance date of this Order.

5. That the Amended Joint Stipulation among the parties to this proceeding, which is incorporated by reference, herein, is hereby approved.

6. That neither the Amended Joint Stipulation entered on April 16, 2007, nor this Order, shall be treated or cited as precedent in future proceedings.

7. That Carolina Water shall revise its calculation of AFUDC as follows:

a. All plant modification fees collected during the year shall be applied to the project additions accruing AFUDC during the year such that AFUDC shall not be calculated on amounts funded by CIAC through plant modification fees.

b. The calculation shall be based on the actual costs for the year.

8. That Carolina Water shall revise its procedures for handling work orders to prevent work-order related costs from being booked directly to plant in service.

9. That Carolina Water shall correct the entry made on its books to remove the amounts refunded from CIAC such that the amounts refunded will be recorded on a system-specific basis.

10. That Carolina Water shall comply with the Order issued on April 15, 2005 in Docket No. W-354, Sub 266, and will begin recording antenna lease revenues in miscellaneous revenues on Carolina Water's books.

11. That Carolina Water shall begin recording all revenues collected in Mt. Carmel in service revenues on its books.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of July, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Renné Vance, Chief Clerk

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APPENDIX A
PAGE 1 OF 9

SCHEDULE OF RATES

for

CAROLINA WATER SERVICE, INC. OF NORTH CAROLINA

for providing water and sewer utility service in

ALL ITS SERVICE AREAS IN NORTH CAROLINA

WATER RATES AND CHARGES

MONTHLY METERED SERVICE:

BASE FACILITIES CHARGES (zero usage)

A. Residential Single Family Residence $ 13.60

WATER AND SEWER – RATE INCREASE

B.	Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 13.60
C.	Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (as in a condominium complex)	$ 12.45
D.	Commercial and Other (Based on Meter Size):	
	<1" meter	$ 13.60
	1" meter	$ 34.00
	1½" meter	$ 68.00
	2" meter	$108.80
	3" meter	$204.00
	4" meter	$340.00
	6" meter	$680.00

USAGE CHARGE:

A.	Treated Water, per 1,000 gallons	$ 4.12
B.	Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.74

MONTHLY FLAT RATE SERVICE:

A.	Single Family Residential	$ 29.70
B.	Commercial per single family equivalent (SFE)	$ 29.70

AVAILABILITY RATES (semiannual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 16.50

METER TESTING FEE [1/]:	$ 20.00
NEW WATER CUSTOMER CHARGE:	$ 27.00

RECONNECTION CHARGES [2/]:

If water service is cut off by utility for good cause:	$ 27.00

WATER AND SEWER – RATE INCREASE

If water service is disconnected at customer's request:	$ 27.00

MANAGEMENT FEE (in the following subdivisions only):

Cambridge	$250.00
Windsor Chase	$ 63.00
Wolf Laurel	$150.00

OVERSIZING FEE (in the following subdivision only):

Winghurst	$400.00

METER FEE:

For 5/8" or 3/4" meters	$ 50.00
For meters greater than 3/4"	Actual Cost

UNIFORM CONNECTION FEES [3/]:

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE	$100.00
Plant Modification Fee (PMF), per SFE	$400.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Blue Mountain at Wolf Laurel	$ 925.00	$ 0.00
Britley	$ 0.00	$ 0.00
Buffalo Creek, Phase I, II, III, IV	$ 825.00	$ 0.00
Cambridge	$ 382.00	$ 0.00
Carolina Forest	$ 0.00	$ 0.00
Chapel Hills	$ 150.00	$ 400.00
Corolla Light	$ 500.00	$ 0.00

WATER AND SEWER – RATE INCREASE

Currituck Club	$ 100.00	$1,900.00
Eagle Crossing	$ 0.00	$ 0.00
Emerald Pointe/Rock Island	$ 0.00	$ 0.00
Forest Brook/Ole Lamp Place	$ 0.00	$ 0.00
Harbour	$ 75.00	$ 0.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Lemmond Acres	$ 0.00	$ 0.00
Monteray Shores	$ 500.00	$ 0.00

Subdivision	CC	PMF
Monteray Shores (Degabrielle Bldrs.)	$ 0.00	$ 0.00
Monterrey (Monterrey, LLC)	$ 0.00	$ 0.00
Quail Ridge	$ 750.00	$ 0.00
Queens Harbour/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Riverwood, Phase 6E (Johnston County)	$ 825.00	$ 0.00
Saddlewood/Oak Hollow (Summey Bldrs.)	$ 0.00	$ 0.00
Sherwood Forest	$ 950.00	$ 0.00
Ski Country	$ 100.00	$ 0.00
Stonehedge (Bradford Park)	$ 441.00	$ 0.00
Victoria Park	$ 344.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Wildlife Bay	$ 870.00	$ 0.00
Williams Crossing	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00

WATER AND SEWER – RATE INCREASE

Winston Plantation	$1,100.00	$ 0.00
Winston Pointe, Phase 1A	$ 500.00	$ 0.00
Wolf Laurel	$ 925.00	$ 0.00
Woodrun	$ 0.00	$ 0.00
Woodside Falls	$ 500.00	$ 0.00

APPENDIX A
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SEWER RATES AND CHARGES

MONTHLY METERED SERVICE - Commercial and Other:

A. Base Facility Charge (Based on Meter Size)

<1" meter	$ 12.50
1" meter	$ 31.25
1½" meter	$ 62.50
2" meter	$ 100.00
3" meter	$ 187.50
4" meter	$ 312.50
6" meter	$ 625.00

B. Usage Charge, per 1,000 gallons (based on metered water usage) — $ 5.60

C. Minimum Monthly Charge — $ 37.25

D. Sewer customers who do not receive water service from the Company/SFE — $ 37.25

MONTHLY FLAT RATE SERVICE: Per Dwelling Unit [4/] — $ 37.25

MONTHLY COLLECTION SERVICE ONLY [5/]:
(When sewage is collected by utility and transferred to another entity for treatment)

A. Single Family Residence — $ 13.50

B. Commercial/SFE — $ 13.50

WATER AND SEWER – RATE INCREASE

MT. CARMEL SUBDIVISION SERVICE AREA

Monthly Base Facility Charge	$ 5.05
Usage Charge, per 1,000 gallons (based on metered water usage)	$ 4.40

REGALWOOD AND WHITE OAK ESTATES SUBDIVISION SERVICE AREA

Monthly Flat Rate Sewer Service

Residential Service	$ 37.25
White Oak High School	$1,175.00
Child Castle Daycare	$ 150.00
Pantry	$ 82.00

NEW SEWER CUSTOMER CHARGE [6/]: $ 22.00

RECONNECTION CHARGE [7/]:

If sewer service is cut off by utility for good cause: Actual Cost

UNIFORM CONNECTION FEES [3/]:

The following uniform connection fees apply unless specified differently by contract approved by and on file with the North Carolina Utilities Commission.

Connection Charge (CC), per SFE	$ 100.00
Plant Modification Fee (PMF), per SFE	$1,000.00

The systems where connection fees other than the uniform fees have been approved by the North Carolina Utilities Commission are as follows:

Subdivision	CC	PMF
Abington	$ 0.00	$ 0.00
Abington, Phase 14	$ 0.00	$ 0.00
Amber Acres North (Phases II & IV)	$ 815.00	$ 0.00
Ashley Hills	$ 0.00	$ 0.00
Bent Creek	$ 0.00	$ 0.00
Brandywine Bay	$ 100.00	$1,456.00
Cambridge	$ 841.00	$ 0.00

WATER AND SEWER – RATE INCREASE

Camp Morehead by the Sea	$ 100.00	$1,456.00
Corolla Light	$ 700.00	$ 0.00
Emerald Pointe/Rock Island	$ 0.00	$ 0.00
Hammock Place	$ 100.00	$1,456.00
Hestron Park	$ 0.00	$ 0.00
Hound Ears	$ 300.00	$ 0.00
Huntwick	$ 0.00	$ 0.00
Independent/Hemby Acres/ Beacon Hills (Griffin Bldrs.)	$ 0.00	$ 0.00

Subdivision	CC	PMF
Kings Grant	$ 0.00	$ 0.00
Kings Grant/Willow Run	$ 0.00	$ 0.00
Kynwood	$ 0.00	$ 0.00
Monteray Shores	$ 700.00	$ 0.00
Monteray Shores (Degabrielle Bldrs.)	$ 0.00	$ 0.00
Mt. Carmel/Section 5A	$ 500.00	$ 0.00
Queens Harbor/Yachtsman	$ 0.00	$ 0.00
Riverpointe	$ 300.00	$ 0.00
Riverpointe (Simonini Bldrs.)	$ 0.00	$ 0.00
Steeplechase (Spartabrook)	$ 0.00	$ 0.00
Stonehedge (Bradford Park)	$ 971.00	$ 0.00
Victoria Park	$ 756.00	$ 0.00
White Oak Plantation	$ 0.00	$ 0.00
Williams Station	$ 0.00	$ 0.00
Willowbrook	$ 0.00	$ 0.00
Willowbrook (Phase 3)	$ 0.00	$ 0.00
Winston Pointe, Phase 1A	$2,000.00	$ 0.00
Woodside Falls	$ 0.00	$ 0.00

MISCELLANEOUS UTILITY MATTERS

BILLS DUE:	On billing date
BILLS PAST DUE:	21 days after billing date
BILLING FREQUENCY:	Bills shall be rendered monthly in all service areas, except for Mt. Carmel which will be billed bimonthly, and the availability charges in Carolina Forest and Woodrun Subdivisions which will be billed semiannually.
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.
CHARGES FOR PROCESSING NSF CHECKS:	$15.00

NOTES:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect the service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

2/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

3/ These fees are only applicable one time, when the unit is initially connected to the system.

4/ Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor building the unit.

5/ The utility shall charge for sewage treatment service provided by the other entity; the rate charged by the other entity will be billed to Carolina Water Service's affected customers on a pro rata basis, without markup.

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6/ These charges shall be waived if sewer customer is also a water customer within the same service area.

7/ The utility shall itemize the estimated cost of disconnecting and reconnecting service and shall furnish this estimate to customer with cut-off notice. This charge will be waived if customer also receives water service from Carolina Water Service within the same service area.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-354, Sub 297, on this the 5th day of July, 2007.

APPENDIX B
PAGE 1 OF 5

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-354, SUB 297

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 Adjust and	)	**NOTICE TO CUSTOMERS**
Increase Rates for Water and Sewer Utility	)	
Service in All of Its Service Areas in North	)	
Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Carolina Water Service, Inc. of North Carolina to charge increased rates for water and sewer utility service in all of its service areas in North Carolina. The new approved rates are as follows:

WATER AND SEWER – RATE INCREASE

WATER RATES AND CHARGES

<u>MONTHLY METERED SERVICE</u>:

Base Facilities Charges (zero usage)

A. Residential Single Family Residence	$ 13.60
B. Where Service is Provided Through a Master Meter and Each Dwelling Unit is Billed Individually	$ 13.60
C. Where Service is Provided Through a Master Meter and a Single Bill is Rendered for the Master Meter (as in a condominium complex)	$ 12.45

D. Commercial and Other (based on meter size):

<1" meter	$ 13.60
1" meter	$ 34.00
1½" meter	$ 68.00
2" meter	$108.80
3" meter	$204.00
4" meter	$340.00
6" meter	$680.00

<u>Usage Charge</u>:

A. Treated Water, per 1,000 gallons	$ 4.12
B. Untreated Water, per 1,000 gallons (Brandywine Bay Irrigation Water)	$ 2.74

<u>Monthly Flat Rate Service</u>:

A. Single Family Residential	$ 29.70
B. Commercial/SFE (single family equivalent)	$ 29.70

WATER AND SEWER – RATE INCREASE

AVAILABILITY RATES (semiannual):

Applicable only to property owners in Carolina Forest and Woodrun Subdivisions in Montgomery County	$ 16.50

Meter Testing Fee [1/]	$ 20.00
New Water Customer Charge	$ 27.00
Reconnection Charges [2/]:	
If water service is cut off by utility for good cause	$ 27.00
If water service is disconnected at customer's request	$ 27.00
Management Fee (in the following subdivisions only):	
Cambridge	$250.00
Windsor Chase	$ 63.00
Wolf Laurel	$150.00

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Oversizing Fee (in the following subdivision only):	
Winghurst	$400.00
Meter Fee:	
For 5/8" or 3/4" meters	$ 50.00
For meters greater than ¾"	Actual Cost

SEWER RATES AND CHARGES

MONTHLY METERED SERVICE - Commercial and Other Non-Residential Users:

A. Base Facility Charges (based on meter size with zero usage)

<1" meter	$ 12.50
1" meter	$ 31.25
1½" meter	$ 62.50
2" meter	$100.00

WATER AND SEWER – RATE INCREASE

3" meter	$187.50
4" meter	$312.50
6" meter	$625.00

B.	Usage Charge, per 1,000 gallons (based on metered water usage)	$ 5.60
C.	Minimum Monthly Charge	$ 37.25
D.	Sewer customers who do not receive water service from the Company per SFE (single family equivalent)	$ 37.25

Monthly Flat Rate Service [3/]:

Per Dwelling Unit	$ 37.25

Monthly Collection Service Only [4/]:
(When sewage is collected by utility and transferred to another entity for treatment)

A.	Single Family Residence	$ 13.50
B.	Commercial/SFE	$ 13.50

APPENDIX B
PAGE 4 OF 5

Mt. Carmel Subdivision Service Area:

Monthly Base Facility Charge	$ 5.05
Usage Charge, per 1,000 gallons (based on metered water usage)	$ 4.40

Regalwood and White Oak Estates Subdivision Service Areas:

Monthly Flat Rate Sewer Service:

Residential Service	$ 37.25
White Oak High School	$1,175.00
Child Castle Daycare	$ 150.00
Pantry	$ 82.00

New Sewer Customer Charge [5/]: $ 22.00

Reconnection Charges [6/]:

If sewer service is cut off by utility for good cause — Actual Cost

WATER AND SEWER – RATE INCREASE

MISCELLANEOUS UTILITY MATTERS

<u>Charges for Processing NSF Checks</u>: $ 15.00

<u>NOTES</u>:

1/ If a customer requests a test of a water meter more frequently than once in a 24-month period, the Company will collect the service charge to defray the cost of the test. If the meter is found to register in excess of the prescribed accuracy limits, the meter test charge will be waived. If the meter is found to register accurately or below such prescribed accuracy limits, the charge shall be retained by the Company. Regardless of the test results, customers may request a meter test once in a 24-month period without charge.

2/ Customers who request to be reconnected within nine months of disconnection at the same address shall be charged the base facility charge for the service period they were disconnected.

3/ Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor building the unit.

4/ The utility shall charge for sewage treatment service provided by the other entity; the rate charged by the other entity will be billed to the affected customers on a pro rata basis, without markup.

5/ These charges shall be waived if sewer customer is also a water customer within the same service area.

6/ The utility shall itemize the estimated cost of disconnecting and reconnection service and shall furnish this estimate to customers with cut-off notice. This charge will be waived if customers also receive water service from Carolina Water Service within the same service area.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of July, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Renné Vance, Chief Clerk

WATER AND SEWER – RATE INCREASE

CERTIFICATE OF SERVICE

I, ____, mailed with sufficient postage or hand delivered to all affected customers the attached Notice to Customers issued by the North Carolina Utilities Commission in Docket No. W-354, Sub 297, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of __________________, 2007.

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 297.

Witness my hand and notarial seal, this the ____ day of ______________, 2007.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________
Date

DOCKET NO. W-1236, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Enviracon Utilities, Inc., Post Office	)	ORDER
Box 610, Tarboro, North Carolina 27886, for Authority	)	GRANTING PARTIAL
to Increase Rates for Sewer Utility Service in Carteret	)	RATE INCREASE
County, North Carolina	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Wednesday, October 4, 2006, at 9:30 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Lorinzo L. Joyner, and James Y. Kerr, II

APPEARANCES:

WATER AND SEWER – RATE INCREASE

For Enviracon Utilities, Inc.:

Odes L. Stroupe, Jr., Bode, Call & Stroupe, L.L.P., Attorneys at Law, P.O. Box 6338, Raleigh, N.C. 27628-6338

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

For the Island Beach & Racquet Club Condominium Owners Association:

Ralph McDonald, Bailey & Dixon, L.L.P., Attorneys at Law, P.O. Box 1351, Raleigh, N.C. 27602

For GR&S Atlantic Beach, L.L.C.:

Daniel C. Higgins, Burns, Day & Presnell, P.A., Attorneys at Law, P.O. Box 10867, Raleigh, N.C. 27605

BY THE COMMISSION: On May 19, 2006, Enviracon Utilities, Inc. (Enviracon, Applicant, or Company), filed an application with the Commission for authority to increase its rates and for approval of emergency interim rates for sewer utility service to its two customers - Island Beach and Racquet Club Condominium Owners Association, Inc., (IBRC) and the Sheraton Atlantic Beach Hotel, which is owned by GR&S Atlantic Beach, LLC (Sheraton or GR&S), in Carteret County, North Carolina. The Commission allowed the interventions of IBRC and GR&S and recognized the intervention of the Public Staff pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On May 23, 2006, the Public Staff filed comments concerning Enviracon's request for an oral argument on the applied for emergency rates. On that same date, the Commission issued an Order Scheduling Oral Argument on the Applied for Emergency Interim Rates. The oral argument was held on May 25, 2006.

On May 31, 2006, the Commission issued an Order Establishing General Rate Case, Suspending Rates, and Granting Interim Rates subject to undertaking to refund any amount of the approved interim rate increase that the Commission ultimately determined to be excessive.

On June 14, 2006, the Commission entered an Order Scheduling Hearing for Wednesday October 4, 2006, and Requiring Customer Notice.

On June 26, 2006, Enviracon filed a Certificate of Service reflecting that it had given notice as required by the Commission's June 14, 2006 Order.

On August 1, 2006, IBRC filed, for consideration as an official document in this docket, a copy of a letter ruling dated July 28, 2006, by the Honorable Benjamin G. Alford, Senior Resident Superior Court Judge, which stated that the civil litigation among certain of the parties to this proceeding pending in Carteret County File No. 05 CVS 1313 had been stayed pending resolution of this matter before the Commission.

On August 16, 2006, Enviracon filed the testimony and exhibits of John Chapman. On August 30, 2006, GR&S filed the testimony and exhibits of Alfred Frazzini and Fredrick W. Hering and the Public Staff filed the testimony and exhibits of Calvin C. Craig, III, Windley E. Henry, and Jerry H. Tweed. On September 15, 2006, Enviracon filed the rebuttal testimony and exhibits of John Chapman.

On September 12, 2006, and September 28, 2006, respectively, Enviracon and the Public Staff filed motions to strike certain portions of the testimony of Alfred Frazzini. Also on September 28, 2006, IBRC filed a motion to strike certain portions of the rebuttal testimony of John Chapman. On October 2, 2006, GR&S filed a response to the motions to strike certain portions of the testimony of Alfred Frazzini filed by Enviracon and the Public Staff.[1]

On October 4, 2006, Enviracon filed its Undertaking to refund any amount of the approved interim rates that may be finally determined by the Commission to be excessive.

On October 4, 2006, the hearing was held as scheduled. Enviracon presented the direct and rebuttal testimony of Mr. Chapman; GR&S presented the testimony of Mr. Frazzini and Mr. Hering; and the Public Staff presented the testimony of Mr. Craig, Mr. Henry, and Mr. Tweed.

On November 1, 2006, Enviracon filed a Request for Extension of Time Within Which to File Briefs and Other Submissions to the Commission. Such request indicated that, if approved, Enviracon would waive its statutory right to place into effect increased rates after the six-month period specified in G.S. 62-135(a) and the 270-day period specified in G.S. 62-134(d) on the understanding that the waiver did not affect Enviracon's right to continue to collect the interim rates approved by the Commission.

On November 9, 2006, the Commission issued an Order Extending Time to File Briefs and Other Submissions.

On December 15, 2006, the Public Staff Late-Filed Report on Tank Collapse Vendor Negotiations, Updated Plant Collapse Expense Schedules, and Emergency Escrow Update was filed.

Based on the application, the testimony and exhibits, and the entire record in this proceeding, the Commission makes the following

[1] At the October 4, 2006 hearing, the Presiding Commissioner granted motions to strike directed at certain portions of witness Frazzini's testimony on relevance grounds and to certain portions of witness Chapman's rebuttal testimony on grounds of lack of personal knowledge. See Transcript Volume 1, Pages 8 – 9, for a specification of specific items that were stricken.

WATER AND SEWER – RATE INCREASE

FINDINGS OF FACT

General Matters

1. Enviracon is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina. Enviracon is a franchised public utility providing sewer service to customers in this State.

2. Enviracon 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 applied for rates for its sewer operations.

3. The test period appropriate for use in this proceeding is the 12-months ended December 31, 2005, updated for known changes through the date of the hearing.

4. At the end of the test year, Enviracon was providing sewer utility service to two flat rate commercial customers, IBRC and the Sheraton.

5. Enviracon's present sewer rates, interim rates, and rates recommended by the Public Staff and accepted by the Company are as follows:

Flat Monthly Rate:	Present	Interim	Public Staff/ Company Temporary Recommended	Public Staff/ Company Final Ongoing Recommended
IBRC	$ 2,515	$ 9,830	$13,536	$ 3,526
Sheraton	$ 4,600	$14,745	$20,303	$ 5,289

6. Enviracon is providing adequate sewer utility service to its customers.

Rate Base

7. The appropriate level of plant in service for use in this proceeding is $7,321.

8. The appropriate amount of accumulated depreciation to deduct from rate base in this proceeding is $1,464.

9. The appropriate level of cash working capital for use in this proceeding is $10,880.

10. The appropriate level of average tax accruals to be deducted from rate base is $1,048.

11. The appropriate level of original cost rate base used and useful in providing sewer utility service is $15,689, consisting of utility plant in service of $7,321; cash working capital of 10,880, reduced by accumulated depreciation of $1,464; and average tax accruals of $1,048.

WATER AND SEWER – RATE INCREASE

Revenues

12. The appropriate level of end-of-period ongoing annual sewer service revenues under existing rates is $85,380.

Ongoing Operation & Maintenance Expenses

13. The appropriate level of salaries and wages to include in this proceeding is $12,948.

14. The appropriate level of contract labor to include in this proceeding is $36,000.

15. The appropriate level of administrative and office expense to include in this proceeding is $806.

16. The appropriate level of maintenance and repair expense to include in this proceeding is $2,192.

17. It is appropriate to remove the plant collapse expenses from ongoing operation and maintenance expenses.

18. The appropriate level of transportation expense to include in this proceeding is $2,029.

19. The appropriate level of electric power expense to include in this proceeding is $6,037.

20. The appropriate level of chemical expense to include in this proceeding is $1,708.

21. The appropriate level of testing expense to include in this proceeding is $5,354.

22. The appropriate level of permit fees to include in this proceeding is $1,210.

23. The appropriate level of sludge hauling expense to include in this proceeding is $4,869.

24. The appropriate level of communication expense to include in this proceeding is $2,876.

25. The appropriate level of legal fee expense to include in this proceeding is $698.

26. The appropriate level of miscellaneous expense to include in this proceeding is $55.

27. The appropriate level of rate case expense to include in this proceeding is $10,260.

WATER AND SEWER – RATE INCREASE

<u>Extraordinary Expenses Including Tank Collapse/Cleanup/Pump and Haul/ Mobile Home Park Damage Claims and Legal Fees</u>

28. On August 3, 2005, a wall on one of the aeration tanks at Enviracon's wastewater treatment plant (WWTP) collapsed, spilling over 50,000 gallons of wastewater into an adjoining mobile home park, a creek, and Bogue Sound.

29. The expenses associated with the cost of cleanup of the August 3, 2005 tank collapse wastewater spill and the subsequent pumping and hauling, which Enviracon asked to be treated as extraordinary expenses and amortized over a two-year period, are as follows:

VENDOR	SERVICE	INVOICE AMOUNT
Hepaco	Cleanup	$138,492
Barnes Environmental, Inc.	Pump and Haul	31,970
Lewis Farms and Liquid Waste	Pump and Haul	19,596
Town of Morehead City	Treatment Cost	20,115
Stroud Engineering, PA	Engineering Certification	1,391
Terracon	Ultrasonic Testing	24,303
OBI Mechanical	Tank Modifications	85,157
Mobile Home Park Residents	Damage Claims	150,065
Town of Atlantic Beach	Emergency Response	621
Unlimited Hauling, Inc.	Tank Cleanout, etc.	6,400
Rountree & Boyette, LLP	Legal	8,110
Bode, Call & Stroupe, LLP	Legal	57,456
DENR	Pump and Haul Permit	1,090
Enviracon Beach Operations	Additional Operations	7,923
Enviracon Utilities	Additional Expenses	25,644
TOTAL		**$578,333**

30. It is appropriate to adjust the amount of extraordinary expenses to be allowed for ratemaking purposes from $578,333 down to $456,612 to reflect reduced amounts negotiated with Hepaco and Terracon, to include updates and adjustments to various expenses, and to reduce the total amount for mobile home park damage claims to $50,000.

31. The appropriate level of tank collapse/clean-up expense to include in this proceeding is $456,612, which includes the following:

VENDOR	ALLOWED
Hepaco	$120,003
Barnes Environmental, Inc.	33,578
Lewis Farms and Liquid Waste	20,961
Town of Morehead City	20,115
Stroud Engineering, PA	1,391
Terracon	21,504
OBI Mechanical	85,157
Mobile Home Park Residents	50,000

WATER AND SEWER – RATE INCREASE

Town of Atlantic Beach	621
Unlimited Hauling, Inc.	6,400
Rountree & Boyette, LLP	8,110
Bode, Call & Stroupe, LLP	57,146
DENR	1,090
Enviracon Beach Operations	7,922
Enviracon Utilities	22,614
TOTAL	$456,612

32. The appropriate level of gross revenues, including gross receipts taxes and regulatory fees, necessary to allow for the recovery of the extraordinary tank collapse/clean-up/pump-and-haul expenses through a temporary rate increment is $486,378.

33. It is appropriate to amortize these extraordinary expenses over a 24-month period beginning when the interim rates were approved in this docket on May 31, 2006.

<u>Depreciation and Taxes</u>

34. The appropriate level of depreciation expense for use in this proceeding is $1,464.

35. The appropriate level of payroll taxes to include in this proceeding is $1,162.

36. Based upon the other findings and conclusions set forth herein, the appropriate level of regulatory fees under present rates for use in this proceeding is $102.

37. Based upon the other findings and conclusions set forth herein, the appropriate level of gross receipts taxes under present rates for use in this proceeding is $5,123.

<u>Margin on Expenses</u>

38. The operating ratio method, which allows a margin on operating revenue deductions requiring a return, is the proper method for determining Enviracon's revenue requirement.

39. A margin of 8.5% on ongoing operating revenue deductions requiring a return is just and reasonable.

40. It is not appropriate to allow an 8.5% margin on the extraordinary expenses associated with the tank collapse, cleanup, pump and haul, mobile home park damage claims, and associated legal fees.

<u>Rates, Fees, and Other Matters</u>

41. The interim rates approved in the May 31, 2006 Order in this docket and the temporary rates to be established by further order of the Commission, based upon conclusions provided herein, include an ongoing level of rates and a temporary rate increment component resulting from an amortization of extraordinary expenses.

WATER AND SEWER – RATE INCREASE

42. Once the final Commission-approved extraordinary expense portion of the rates has been properly collected by Enviracon, then the ongoing rates for Enviracon should be reduced to $5,289 per month for GR&S and $3,526 per month for IBRC.

43. The appropriate level of end-of-period ongoing annual sewer service revenues is $105,773, which represents an increase of $20,393 over the existing level of end-of-period revenues. The rate component approved herein related to such revenues, which excludes the temporary increment for extraordinary expense recovery, will allow Enviracon the opportunity to earn the 8.5% margin found reasonable herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 THROUGH 6

The evidence supporting these findings of fact is contained in the Company's application and in the Commission's records. These findings are primarily informational, procedural, and jurisdictional in nature, and the matters that they involve are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 THROUGH 11

The evidence supporting these findings of fact is contained in the testimony of Public Staff witnesses Henry and Tweed and Company witness Chapman. The following table summarizes the amounts that the Company and the Public Staff provided as the proper levels of rate base for sewer operations to be used in this proceeding:

Item	Company	Public Staff
Plant in service	$ 0	$ 7,321
Accumulated depreciation	0	(1,464)
Cash working capital	0	10,880
Average tax accruals	0	(1,048)
Original cost rate base	$ 0	$ 15,689

As shown in the preceding table, the Company did not present an amount on its application for original cost rate base at December 31, 2005. During cross-examination by the Public Staff, witness Chapman testified that Enviracon is willing to accept for purposes of this proceeding all the Public Staff's adjustments and the Public Staff's recommended rates. IBRC and GR&S did not present an amount for original cost rate base in their testimony or exhibits.

Since none of the parties presented any evidence contesting the level of original cost rate base recommended by the Public Staff, the Commission finds and concludes that the appropriate level of original cost rate base for use in this proceeding is $15,689.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding is found in the testimony of Public Staff witnesses Henry and Tweed and the application filed in this docket. None of the parties contested the level of end-of-period ongoing annual sewer service revenues under existing rates recommended by the Public Staff. Therefore, the Commission concludes that the appropriate level of end-of-period ongoing annual sewer service revenues under existing rates for use in this proceeding is $85,380.

WATER AND SEWER – RATE INCREASE

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13 THROUGH 27

The evidence supporting these findings is found in the testimony of Public Staff witnesses Henry and Tweed, Enviracon witness Chapman, and GR&S witnesses Hering and Frazzini and in the entire record in this docket. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of ongoing operation and maintenance expenses to be used in this proceeding:

Item	Company	Public Staff	Difference
Salaries and wages	$ 12,948	$ 12,948	$ 0
Contract labor	36,000	36,000	0
Administrative and office	771	806	35
Maintenance and repairs	6,630	2,192	(4,438)
Plant collapse	281,325	0	(281,325)
Transportation	3,456	2,029	(1,427)
Electric power	7,081	6,037	(1,044)
Chemicals	2,013	1,708	(305)
Testing	5,869	5,354	(515)
Permit fees	1,413	1,210	(203)
Sludge hauling	6,733	4,869	(1,864)
Communications	5,952	2,876	(3,076)
Legal fees	4,583	698	(3,885)
Miscellaneous	55	55	0
Rate case	18,760	10,260	(8,500)
Total O&M expenses	$ 393,589	$87,042	$(306,547)

The Public Staff made numerous adjustments to the Company's operation and maintenance expenses as reflected on Henry Exhibit I, Schedule 3. During cross-examination by the Public Staff, witness Chapman testified that Enviracon is willing to accept for purposes of this proceeding all of the Public Staff's adjustments and the Public Staff's recommended rates. GR&S witness Hering testified that he had reviewed the Public Staff's proposed adjustments to Enviracon's ongoing base rates and that he agreed with the Public Staff's recommended adjustments. However, at a later point during his direct examination, witness Hering further stated that he did have some concerns as to the salary component of Enviracon's ongoing operating expenses. IBRC did not present any witness in this proceeding and, in its post-hearing Brief, IBRC only addressed issues relating to the recovery of certain items of extraordinary expenses resulting from the holding tank collapse. Based upon the foregoing, the only matters of disagreement between the parties regarding the appropriate amount of ongoing operation and maintenance expenses that should be included in the calculation of Enviracon's ongoing rates is the amount of salaries and wages expense and the plant collapse expenses.

Since both the Company and GR&S have accepted the Public Staff's recommended ongoing levels of contract labor, administrative and office, maintenance and repairs, transportation, electric power, chemicals, testing, permit fees, sludge hauling, communications, legal fees, miscellaneous expense, and rate case expense, the Commission finds and concludes that the levels recommended by the Public Staff are appropriate for use in this proceeding. As to the matter of the appropriate level of plant collapse expenses, the Commission believes that it would be appropriate to remove the plant collapse expenses from ongoing operation and maintenance expenses, and it will address the recovery of such expenses in this present general rate case proceeding hereinafter in the Evidence and Conclusions for Findings of Fact Nos. 29 through 34.

SALARIES AND WAGES

Public Staff witness Tweed testified that Enviracon included salaries for two of its officers, John Chapman and James Proctor, in the amount of $12,948 in developing its proposed rates. Enviracon stated in its response to a Public Staff data request that Mr. Chapman worked on Enviracon's operations 43.3 hours per month and that Mr. Proctor worked 12 hours per month. The duties performed by Mr. Chapman were deposits, billing, accounts payable, checking account balancing, record keeping, WWTP and system visits and operations, attending meetings, DENR reports, Commission reports, reviewing engineering plans and reports, coordinating between users and other parties, and handling daily phone calls for the company. The duties performed by Mr. Proctor included WWTP and system visits and operations, coordination between company and contract operators, attending meetings, and reviewing engineering plans and reports. Witness Tweed testified that the duties performed by Messrs. Chapman and Proctor were reasonable utility duties. The hourly rate paid to Mr. Chapman and Mr. Proctor was $19.50 per hour, which witness Tweed testified he did not believe to be excessive. Witness Tweed stated that he had reviewed the duties and hourly rates, and recommended a salary level of $12,948 as being reasonable.

GR&S witness Hering testified that he agreed with the Public Staff's adjustments to Enviracon's base rates. Witness Hering further testified that, looking at the duties of Mr. Chapman and Mr. Proctor, some of the duties appear to be fairly simplistic clerical duties, and some of the reviewing of engineering type plans should probably be capitalized. However, witness Hering did not provide any proposed adjustment to the salaries and did not quantify how much of the salaries he believed should be capitalized.

IBRC did not explicitly address this issue in its post-hearing Brief.

Enviracon witness Chapman testified in rebuttal that the salary hours of 43.3 hours per month for Mr. Chapman and 12 hours per month for Mr. Proctor did not contain the extra time to implement capital upgrades or changes required by DENR. He testified that these DENR-required capital upgrades would require approximately an extra 5 hours per week for himself and approximately 2.5 hours per month for Mr. Proctor.

After reviewing all of the evidence on this issue, the Commission concludes that the $12,948 level of salaries for the two Company officers is a reasonable ongoing level of operating expense to include in this proceeding. By virtue of being the officers of Enviracon, the franchise holder and DENR permit holder, both Mr. Chapman and Mr. Proctor are required to devote time to operation and management of the wastewater system and Company administrative functions. Both Messrs. Chapman and Proctor are Grade IV wastewater operators, the highest license grade in North Carolina, and both have 20 years experience in wastewater operations. It is reasonable for them to make routine and prudent inspection visits to the system to insure proper operation by the contract operator. As a result, it is reasonable to include $12,948 in salary expense for Messrs. Chapman and Proctor in developing Enviracon's rates.

WATER AND SEWER – RATE INCREASE

SUMMARY CONCLUSION

Based upon the foregoing, the Commission concludes that the appropriate ongoing level of operation and maintenance expenses for use in this proceeding is $87,042.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28 THROUGH 32

Extraordinary Expenses Including Tank Collapse/Cleanup/Pump and Haul/ Mobile Home Park Damage Claims and Legal Fees

The evidence supporting these findings is contained in the application, the testimony of all of the witnesses in this proceeding and the entire record in the case.

There was considerable concern expressed by all parties as to the reasonableness of some of the tank collapse/clean-up vendor invoices, in particular those of Hepaco and Terracon. There was also considerable concern expressed by the two customers regarding whether there should be any amounts for payment of claims for damage to the Croatan Mobile Home Park or payment of Enviracon's legal fees associated with the tank collapse/cleanup/pump and haul in developing an appropriate level of extraordinary expense. There was also concern expressed regarding the fact that Enviracon did not have insurance to cover the mobile home park damage claims.

HEPACO AND TERRACON INVOICES

Hepaco was the contractor hired by Enviracon to clean up the wastewater spill, including its effect on the Croatan Mobile Home Park. Concern was expressed by all of the parties in this proceeding regarding the magnitude of the charges by Hepaco and the amount of markup on supplies and services provided.

GR&S stated that it does not oppose funding appropriate tank collapse expenses included in Enviracon's request; however, GR&S noted that it does oppose payment of those tank collapse expenses that are unreasonable and a product of the price gouging to which Enviracon was subjected. GR&S pointed out that Enviracon witness Chapman estimated that Hepaco, Enviracon's clean-up contractor, whose billings total in excess of $130,000, overcharged Enviracon at least $15,000 to $20,000. GR&S also noted that the unreasonableness of Hepaco's charges, as well as those of Terracon, another Enviracon contractor, was also described by Public Staff witness Tweed, who estimated that Enviracon was overcharged by 20%. GR&S recommended that, to the extent that the Commission treats those costs as "operating expenses", then, under G.S. 62-133.1(a), only "reasonable operating expenses" should be considered for ratemaking purposes. Thus, GR&S asserted that, if the Hepaco and Terracon billings were unreasonable, they cannot be treated as "reasonable operating expenses".

Public Staff witness Tweed noted that Hepaco may have double-charged Enviracon for some items; specifically, (1) Hepaco billed Enviracon for items such as boots, body suits, and latex gloves and also assessed a separate charge of $7.50 per man-hour of labor for use of personal protective equipment; (2) Hepaco included a $2.00 per hour rental on wheelbarrows while charging separately for the purchase of several wheelbarrows; and (3) Hepaco's invoice included per diem charges at $95.00 per day per person on several days, while billing separately for meals on some of the same days. Further, witness Tweed noted that Enviracon may have been overcharged by Hepaco on certain items; specifically, when lime was listed on the invoice under disposables, it was charged at $20.00 per bag for 178 bags, and when it was listed under other direct cost, it was charged at an average of about $3.00 per bag for those bags purchased at Lowe's or AGRI Supply.

Public Staff witness Tweed testified that Terracon provided ultrasonic testing services to identify welds that needed replacement on the remaining usable wastewater treatment tank after one of the tanks had collapsed due to failure of the welds. The welds on the tank were replaced, and Terracon tested again to insure the integrity of the welds. Witness Tweed testified that a portion of the $24,303 invoice from Terracon resulted from travel time and mileage incurred by traveling to and from the job site each day as opposed to staying overnight, which witness Tweed believed would have been more efficient.

The Public Staff recommended that Enviracon attempt to negotiate with Hepaco and Terracon for lower payments, and the Public Staff's legal department volunteered to work with Enviracon to facilitate these negotiations.

The Public Staff's Late-Filed Report on Tank Collapse Vendor Negotiations, filed on December 15, 2006, advised the Commission that the Public Staff, on behalf of Enviracon, had negotiated a settlement with both Hepaco and Terracon. The settlement provided that both Hepaco and Terracon, as long as each was paid the full invoice principal in 24 monthly installments, would eliminate the 18% per annum interest rate stated in the paper writings executed by Enviracon and Hepaco and Enviracon and Terracon prior to the commencement of the tank collapse emergency work. The Public Staff stated in its Late-Filed Report that the elimination of the 18% per annum interest resulted in significant reductions. The Public Staff recommended that the Commission approve as an extraordinary expense the full principal amounts of $120,003 for Hepaco and $21,504 for Terracon.

IBRC did not explicitly address this issue in its post-hearing Brief.

The Commission understands that the 18% per annum interest rate agreed to in contracts executed by Enviracon and Hepaco and Enviracon and Terracon prior to the commencement of the tank collapse emergency work resulted in Enviracon having significant interest expense obligations to both Hepaco and Terracon. Based upon a comparison of the estimated interest expense to be incurred by Enviracon under the executed agreements with Hepaco and Terracon and the estimated amount of overcharges presented by witnesses Chapman and Tweed, the Commission concludes that the settlement negotiation which resulted in the elimination of the interest expense obligations is more beneficial to customers. Thus, the Commission concludes that the reasonable and appropriate amounts to include as extraordinary tank collapse expenses is the principal amount of $120,003 for the Hepaco invoice and $21,504 for the Terracon invoice.

MOBILE HOME PARK DAMAGE CLAIMS

The parties disagree on whether Enviracon should be allowed to recover through rates certain mobile home park damage claims which arose as a result of the August 3, 2005, WWTP tank collapse. Enviracon initially sought in this docket to recover through rates mobile home park damage claims totaling $153,071. However, the Public Staff subsequently adjusted the total mobile home park damage claims provided by Enviracon downward to $150,065 to reclassify certain expenses which were more appropriately included in another category within tank collapse expenses. The Public Staff observed that these claims have been sharply reduced from the total of approximately $350,000 presented to the Commission at the December 6, 2005, evidentiary hearing in Docket No. W-1236, Sub 1 (Sub 1 Proceeding).

Enviracon witness Chapman testified that seven property owners were affected as a result of the approximately 50,000 gallons of partially treated wastewater overflowing into the Croatan Mobile Home Park, the property adjoining the WWTP. Witness Chapman stated that one mobile home was damaged beyond repair and would have to be replaced and that the air conditioning, ductwork, and underpinnings on six other mobile homes were damaged or destroyed and needed to be repaired or replaced.

Witness Henry stated that the amount of unpaid mobile home park damage claims was $141,493[1]. The largest claim estimate was $87,262 to replace a 15-year-old mobile home, including personal property loss and other expenses. The remaining claim estimates of $54,231 involved replacing air conditioners and ductwork, providing temporary living accommodations, and paying other miscellaneous expenses for the other mobile homes that were damaged during the collapse.

The Public Staff stated that, based upon evidence obtained in the present proceeding, it had re-evaluated its prior recommendation to the Commission in the Sub 1 Proceeding regarding mobile home park damage claims. Specifically, the Public Staff recommended in the Sub 1 Proceeding that Enviracon's two customers not be required to pay through rates the approximately $350,000 in mobile home park damage claims as requested by Enviracon in that proceeding. Public Staff witness Tweed testified in the present general rate case proceeding that the Public Staff had decided to re-evaluate its position on whether the claims should be included in rates. Witness Tweed testified that the Public Staff met with officials of the North Carolina Department of Insurance and, as a result of that meeting and the testimony of Enviracon witness Chapman in this docket, had concluded that the Public Staff should change its prior position as it was reasonable for Enviracon to be self-insured given the circumstances.

Public Staff witness Henry testified that one basis for the Public Staff's recommendation for inclusion of the mobile home park damage claims was that Enviracon was unable to obtain the proper insurance that would compensate the claimants. He stated that the Public Staff agrees that a reasonable level of insurance premiums, deductibles, and claims are generally included in utility rates. Witness Henry further observed that he has been involved in a Heater Utilities, Inc. (Heater) case where self-insurance and claims were involved, and that the Commission historically has included claims paid, as well as premiums and deductibles, in the customers' rates.

[1] Witness Henry testified that $8,572 of the mobile home park damage claims had already been paid during the test year.

Witness Henry noted that the Public Staff met with the North Carolina Department of Insurance to discuss the claims against Enviracon, the type of insurance that could likely have been available to the Company, and the amount that would likely be recoverable from insurance companies for the mobile home park damages. He remarked that, after the Public Staff's discussions with the North Carolina Department of Insurance, the Public Staff reviewed each of the damage claims and now recommends $95,000 as a reasonable settlement amount to include in rates to compensate the owners for their losses. Witness Henry testified that any amounts of claims paid over the $95,000 of extraordinary expenses, which the Public Staff recommends be included in rates, should be absorbed by Enviracon's shareholders.

The Public Staff contended that it is reasonable to include these expenses as extraordinary expenses to be recovered from ratepayers and that the reasonable level of mobile home park damage claims to include as extraordinary expenses is $95,000, which should be amortized over a two-year period.

Enviracon witness Chapman testified that, prior to the August 3, 2005 tank failure, Enviracon had attempted to acquire insurance coverage for environmental accidents, but had been informed that such coverage was not available or would be cost prohibitive.

Enviracon witness Chapman testified that he understood that many Commission-regulated utilities are self-insurers and that the claims paid are included in rates approved by the Commission. He explained that many utilities with insurance have very high deductibles, and that claims are paid because the deductibles are included in rates. He also noted that those public utilities that do have insurance have their premiums increased based upon claims experience. He further maintained that those increased premiums paid by the utility are included in the utility's succeeding general rate case, and thus the customers pay for the increased insurance premiums through the customers' increased utility rates.

Further, witness Chapman testified that Enviracon would accept the Public Staff's recommended $95,000 settlement amount, although he noted that settling all the claims for that amount may not be a certainty. Mr. Chapman remarked that his attorney advised him that litigation costs in the Carteret County General Court of Justice for all of these mobile home park damage claims could well approach the actual amount of the claims and certainly could consume the $95,000 the Public Staff recommends as a settlement amount to be included in rates. Mr. Chapman contended that his attorney, Odes Stroupe, and he both believed there was a pretty good chance that the mobile home park damage claims could be resolved for something near the $95,000 recommended as a settlement amount by the Public Staff. Mr. Chapman asserted that this claim resolution process would be similar to that employed by water companies such as Heater and electric companies such as Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc. and/or Duke Energy Carolinas, Inc., which to a large extent are self-insurers and which seek and obtain Commission approval to place in utility rates the amount of disputed claims that are resolved to reduce legal costs and move forward. Witness Chapman testified that any settlement amounts over the $95,000 that the Public Staff recommends would either be funded by Enviracon's shareholders or Enviracon would seek further legal advice.

GR&S has recommended that the Commission refuse Enviracon's request that the two customers be required to provide funding to settle the mobile home park damage claims because the damage claims are not legitimate operating expenses for Enviracon, which affirmatively denies that it is liable on these claims. GR&S witness Frazzini testified that GR&S disputes that Enviracon has liability to the mobile home park claimants and would rather see Enviracon abandon its operations than be allowed to collect from Enviracon's customers, through rates, funds to pay the mobile home park claimants. GR&S witness Hering testified that he believed the Commission found in a prior order in the Sub 1 Proceeding that Enviracon was not liable for the tank collapse. Additionally, Mr. Hering contended that Enviracon should have either maintained insurance or maintained reserve accounts for claims of this type. Witness Hering further stated that the type of public utilities that self-insure are large companies with large customer bases, effectively having the resources to self-insure a portion of their risk.

GR&S believes the effort to settle these claims will likely fail as the Public Staff recommends that the customers fund only approximately 62% of the amount of mobile home park damage claims funding requested by Enviracon. Because this effort will either fail, or lead Enviracon to seek additional funding from the customers, or both, GR&S asserted that the Commission should deny this request, just as it did when Enviracon presented this same request as part of its Application for Authority to Make Emergency Special Assessment to Ratepayers and/or Application For Authority to Discontinue Public Utility Service in the Sub 1 Proceeding. GR&S maintained that, if Enviracon ultimately fails, then the customer funding provided to Enviracon for use in paying its debts or in settling doubtful and disputed claims will not have been well spent. GR&S further maintained that the customers will have received no benefit and the forced provision of that funding to Enviracon will not have been in the public interest.

In addition, GR&S witness Frazzini testified that the parties needed to reach some workable resolution with regard to insurance coverage related to the wastewater system. Witness Frazzini noted that GR&S, as a customer of Enviracon that had provided significant funding, would like to know the amount of the premiums Enviracon would have to pay for future insurance coverage. According to witness Frazzini, any comprehensive solution to the problems and issues pertaining to the existing wastewater system would require that the parties evaluate the risks associated with the future operation of the system and determine the extent to which insurance coverage was available in order to make informed decisions with regard to the cost and benefit of such insurance coverage. Witness Frazzini stated that, if insurance coverage was not commercially available on a going-forward basis, the customers would need to know this fact, particularly since, in the present situation, it appeared that Enviracon's plan to "self-insure" included passing any losses through to its customers. Further, witness Frazzini concluded that, while Enviracon made the decisions regarding insurance coverage, the customers of Enviracon ultimately funded the consequences of those decisions. Witness Frazzini opined that all interested stakeholders deserved input with regard to how such risk issues related to the operation of the wastewater system would be addressed in the future.

IBRC contended that there was no new evidence in this present proceeding to support the Public Staff's change of position from the Sub 1 Proceeding. According to IBRC, Enviracon had asserted in the Sub 1 Proceeding that it had attempted to obtain liability and casualty insurance but was unable to do so. IBRC maintained that Enviracon's status is in no way analogous to that of the typical, partially self-insured utility as described by witnesses Henry and Hering. IBRC contended that Enviracon was not partially insured and maintained no reserve accounts.

IBRC pointed out that, normally, public utilities, in the course of business, insure against loss and damage. Additionally, IBRC maintained that Enviracon had a contractual duty to both customers to maintain liability and casualty insurance on the WWTP plant but failed to carry either type of insurance. IBRC asserted that most, if not all expenses resulting from removal and replacement of the collapsed tank would have been covered by comprehensive casualty insurance. IBRC further asserted that most legitimate, third-party damage claims would have been covered by appropriate liability insurance. Consequently, IBRC concluded that it would be manifestly unfair to allow Enviracon to recover from its customers both casualty and liability losses, which should have been insured against. IBRC further opined that to allow recovery of uninsured third-party claims would be unfair, unjust, and unreasonable and would set an unacceptable precedent.

The evidence summarized above raises two primary issues that must be addressed by the Commission regarding the mobile home park damage claims. First, the Commission must determine if the claims arising from the damages incurred in the mobile home park can be legitimately included in the rates recovered from Enviracon's ratepayers. Second, if the claims can be included in rates, in what amount and in what manner should the claims be recovered from ratepayers.

With regard to the former issue, both GR&S and IBRC strenuously objected to the claims being included in rates. Despite their objections and for the following reasons, the Commission concludes that mobile home park damage claims can be legitimately recovered in rates. In the Sub 1 Proceeding, Enviracon witness Chapman testified that all the post-collapse analyses and inspections indicated that the collapse had been caused by faulty welds at joints and "that there was virtually no way that this could have been <u>visually</u> discovered prior to the collapse (the welds were covered by paint and submerged in wastewater").[1] Accordingly, the Commission concluded in the Sub 1 Proceeding that the tank collapsed due to the failure of welded joints at one or more locations and that the faulty welding occurred prior to Enviracon's operation and ownership of the WWTP.

Based on that conclusion, GR&S and Enviracon contended in this present proceeding that Enviracon is not legally responsible for the claims and has no obligation to pay the damages. GR&S argued that the mobile home park damage claims should not be included in Enviracon's rates because Enviracon has no legal responsibility for the resulting damages. Based upon the evidence in the record, the Commission reaffirms its conclusion in the Sub 1 Proceeding that:

> . . . Enviracon's customers should not be required to pay these third-party damage claims against the utility. The utility company should protect themselves from this type of liability, and the failure to do so does not automatically transfer the burden to the customers. For the Commission to rule in favor of Enviracon on this issue is not justified and would set an unacceptable precedent in the regulation of utility companies. The Commission, therefore, concludes that the customers should not be required to pay for the mobile home park damage claims.

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[1] See Docket No. W-1236, Sub 1, Order Authorizing Surcharge in Lieu of Abandonment, issued April 7, 2006, Page 17.

However, the Commission does not have final jurisdiction to resolve tort claims and cannot render a binding decision with respect to Enviracon's liability to the individual claimants, who are not bound by our determination and are free to seek redress for perceived injuries caused by Enviracon's negligence in the General Court of Justice. If the residents exercise their right to challenge Enviracon and thereby, indirectly challenge the Commission's decision in this case, Enviracon might be required to litigate each claim separately in Carteret County Court. With the likely prospect of multiple jury trials, Enviracon's attorneys and expert witness fees may well exceed the $95,000 settlement amount recommended by the Public Staff. Enviracon would be required to defend these civil actions, plus pay attorney and expert witness fees, regardless of the ultimate outcome. In either event, Enviracon could apply to recover its legal and expert witness fees as extraordinary expenses with the appropriate amortization period in a future rate case. Enviracon's testimony leaves open the possibility that Enviracon would seek to recover additional funds from the ratepayers should the amount authorized in this present proceeding prove insufficient. Hence the attorneys fees, expert witness fees, other litigation costs, and possible jury awards may substantially exceed the $95,000 the Public Staff has recommended as reasonable to be included in this proceeding as an extraordinary expense or even the $141,493 in claims which are currently outstanding. Thus, even if the Commission were to deny rate recovery for these third-party claims in these proceedings, there is a very real possibility that these claims in addition to costs inherent in litigating these claims would ultimately be recovered from the customers through rates in subsequent rate cases.

Both GR&S and IBRC are particularly adamant that the Commission should not permit Enviracon to recover the mobile home park damage claims in rates. Both argue that Enviracon failed to procure insurance which would have mitigated the amount of damages which Enviracon and indirectly, the customers themselves, would have been required to pay out of pocket as a result of the tank collapse. The customers' vigor in advocacy is fueled by their belief that Enviracon was contractually required to procure insurance to protect the customers from this very risk. The customers' argument, when distilled to its essence, is that Enviracon made an unreasonable decision when it chose not to purchase insurance and should not thereafter be rewarded for this "bad" business decision.

The Commission generally prefers that utilities should purchase insurance to mitigate liability for occurrences such as the mobile home park damage claims. This preference is qualified, however, by the following caveat: the Commission prefers that utilities procure insurance when such coverage is reasonably priced and generally available. There was no persuasive evidence presented in this proceeding that coverage of the type necessary to cover these claims was reasonably priced and generally available. Moreover, there was no evidence that, if such coverage had been available, these claims would not have been excluded. Public Staff witness Tweed testified that, after the Public Staff's meeting with the North Carolina Department of Insurance, it was the Public Staff's belief that it was unlikely Enviracon could have obtained environmental insurance at all and that, even if Enviracon had been able to obtain environmental insurance, there would be more exclusions than inclusions in the policy.

Witness Frazzini did testify that he was able to secure insurance on the property with one telephone call after he became aware that GR&S property containing utility operations was uninsured. Witness Frazzini's testimony about his post-collapse insurance procurement efforts failed to provide information detailing the costs and scope of coverage. These details are pertinent to a Commission determination as to the reasonable availability of coverage. The Commission is not persuaded by Frazzini's testimony that insurance was reasonably priced and generally available. Based on the record before the Commission, the Commission simply cannot say with any degree of confidence that insurance to cover these claims was reasonably and generally available to Enviracon for purchase, particularly in light of the documentary evidence to the contrary provided by Enviracon.

Thus, in this case, the Commission finds that Enviracon's decision to, in essence, self-insure was reasonable and that it would be reasonable to include funding to settle these third-party claims in rates.[1] In doing so, the Commission disagrees with GR&S's assertion that the customers will have received no benefit from the forced provision of mobile home park damage claims funding to Enviracon and such funding will not have been in the public interest. The continued existence of these claims impairs Enviracon's ability to provide adequate service, making resolution of these claims a clear benefit to customers.

Having concluded that it is reasonable to include funding for the third-party liability claims in rates and that doing so would be in the public interest and beneficial to the two customers, the remaining question that the Commission is now required to answer is how and in what amount funds should be collected for such claims now. The Public Staff and Enviracon proposed that the customers contribute $95,000 over a two-year period to be used to settle the mobile home park damage claims. The Public Staff further proposed that Enviracon shareholders should be required to pay any funds in excess of $95,000 to settle such claims. Enviracon generally agreed with the Public Staff's proposal but reserved the right to seek further relief from the Commission. The customers are concerned that the Commission's approval of this process would encourage Enviracon to view the customers as a source of funds for all its endeavors, no matter how imprudent.

In the Commission's view, based on the present state of this record, it is unwise to require the customers to advance the entire $95,000 that the Public Staff estimates would settle these claims. Foremost among the Commission's reasons for reaching this conclusion is the concern articulated by the customers that the claims cannot be settled for that amount estimated. Further, the Commission believes that the plan as proposed provides little incentive for Enviracon to settle the claims for an amount less than $95,000. For these reasons and others, the customers argued that no funding mechanism should be established. The Commission believes, however, that the establishment of some type of funding mechanism is a necessity if these claims are to be settled for some reasonable amount and the prospect of prolonged and expensive litigation is to be avoided.

For that reason, the Commission finds that it is reasonable to establish a funding mechanism, the Claim Settlement Fund (CSF), to encourage and facilitate the settlement of the third-party damage claims and that the rates to be approved should include a temporary rate increment component to allow Enviracon to collect $50,000 over a two-year period. The

[1] The Commission notes that in the Heater general case, Docket No. W-274, Sub 478, the Commission recognized that public utilities self-insure and/or have insurance with deductibles and retention factors, resulting in claims reasonably and prudently paid being included in the public utilities' insurance expense component of rates.

Commission believes that this amount should be sufficient to allow Enviracon to initiate settlement discussions with the residents who have filed damage claims and to resolve most, if not all claims. Enviracon is encouraged to use its best efforts to settle claims as reasonably and prudently as is possible and, to that end, the Commission requires that Enviracon's shareholders contribute 15% of the settlement amount of each claim paid to the claimant and that no more than 85% of the agreed-upon settlement amount may be paid from the CSF to any individual claimant.

The Commission recognizes that the CSF it has created in this Order may not presently provide the exact amount of recovery that will ultimately need to be provided by the ratepayers; however, the Commission firmly believes that the CSF provides Enviracon with the certainty that is necessary for meaningful settlement negotiations, fairly protects the interests of the utility customers, and requires the Applicant to share in the inherent risk of providing utility service. Because the Commission recognizes that the amount of the CSF approved herein may be more or less than 85% of the actual settlements reached, Enviracon should be required to file a final accounting with the Commission detailing the final settlement amount for each claimant and may, if necessary, petition the Commission to increase funding for the CSF; provided, however, that total customer funding for the CSF, including the initial outlay, shall not exceed $95,000.

In addition, the Commission agrees with GR&S witness Frazzini that all interested stakeholders deserve input with regard to how certain operational risk issues, specifically insurance coverage for the wastewater system, should be addressed in the future given the substantial expense resulting from the tank collapse, the precarious nature of Enviracon's finances, and the substantial control over the utility's future exercised by Enviracon's only two customers. The Commission therefore finds that it is in the interest of all parties and the public in general for the parties to meet in an attempt to secure reasonable insurance to cover such unanticipated events.

Based upon the foregoing, the Commission finds that a CSF in the amount of $50,000 should be established to settle the mobile home park damage claims and such fund should be established through a temporary rate increment to be collected over a two-year period, commencing with the approval of the interim rates. Additionally, the Commission finds good cause to require Enviracon to provide a final accounting detailing the final amount paid or to be paid to each claimant. Such accounting should be submitted to the Commission every six months beginning on September 21, 2007, or sooner in the event that all claims have been settled or the settlement claims have exceeded $50,000. The Commission, upon review of the final claim amounts, will issue a further order setting forth any adjustment or true-up related to the temporary rate increment if Enviracon successfully settles the claims for an amount less than $50,000. Should Enviracon petition the Commission for additional funding for the CSF, such additional funding, if any, shall be approved by further order of the Commission.

Further, as previously stated, the Commission finds that Enviracon should be required to meet with its two customers within 30 days of the issuance date of the final Order in this proceeding to provide an opportunity for all parties to participate in the formulation of a prospective solution to Enviracon's future insurance needs. In addition, Enviracon shall be required to file a report with the Commission within 60 days of the issuance date of the final

Order in this present proceeding detailing its specific activities involved in, and the anticipated costs of, obtaining insurance coverage for the wastewater system, including the status of such efforts. If Enviracon enters into a binding insurance agreement prior to the filing of such report, said report should list the types of insurance coverage obtained, the level of coverage obtained, the associated premiums, and the term of coverage.

LEGAL FEES

The parties disagree on whether Enviracon should be allowed to recover through rates certain legal fees which were incurred as a result of the August 3, 2005, WWTP tank collapse, the environmental cleanup, the pumping and hauling, and the Sub 1 Proceeding before the Commission. Enviracon sought to recover, as an extraordinary expense, attorneys fees totaling \$65,256. The attorney fees for Bode, Call & Stroupe totaled \$57,146, and the attorney fees for Rountree and Boyette totaled \$8,110.

Public Staff witnesses Tweed and Henry, both recommended that these attorneys fees be included as extraordinary expenses relating to the WWTP tank collapse and that such fees be amortized over a two-year period.

Public Staff witness Henry stated he reviewed these legal invoices and determined the charges were reasonable. Witness Henry testified that the entire \$65,256 in legal fees was for legal services relating to issues presented in the Sub 1 Proceeding. He asserted that the attorneys fees occurred within the test year, were reasonably incurred, prudent, and necessary. He further explained that the attorneys fees relating to this general rate case were included in the rate case expenses and were not included in these extraordinary expenses.

Public Staff witness Tweed testified that he reviewed all the invoices and hours of Wayne Boyette and Odes Stroupe and did not see anything that he thought should be adjusted except one item on a Bode, Call & Stroupe invoice pertaining to an Enviracon application filed in Docket No. W-1236, Sub 3, for Commission approval of a rule on grease disposal, and Public Staff witness Henry made that adjustment. Witness Tweed noted that this general rate case was a continuation of the Sub 1 Proceeding, since Enviracon was continuing to seek Commission approval of rates to pay for the WWTP tank collapse expenses, the environmental clean-up expenses, the pump-and-haul expenses, the mobile home park damage claims, and the related attorneys fees.

Witness Tweed also observed that Enviracon in the Sub 1 Proceeding applied to the Commission to collect the tank replacement costs, and explained to the Commission the circumstances surrounding the tank collapse and the necessity for the tank replacement. He further stated that the collapsed tank has now been replaced; and GR&S, IBRC, and Enviracon have all benefited.

GR&S contended that the Commission should refuse Enviracon's request to recover its legal fees incurred in connection with the Sub 1 Proceeding since those expenses were not related to this proceeding, were not part of the cost of Enviracon's rate case, and were associated with the flawed strategy that Enviracon elected to pursue last year. GR&S asserted that Enviracon's effort in the Sub 1 Proceeding to either assess the customers or abandon the plant was a failure; and, accordingly, it would be neither appropriate nor equitable for the Commission to require Enviracon's customers to pay Enviracon's attorneys fees incurred in pursuit of a failed strategy that yielded no benefit to the customers or the utility. GR&S further asserted that Enviracon's customers should not be made to pay twice for attorneys fees effectively incurred in pursuit of the same relief, first in the Sub 1 Proceeding, in which an assessment or abandonment was pursued, and a second time in this general rate case proceeding.

IBRC did not explicitly address this issue in its post-hearing Brief.

The Commission believes that the Sub 1 Proceeding provided the Commission significant information concerning the circumstances surrounding the tank collapse; the cause of the tank collapse; the required environmental cleanup; the pumping and hauling to provide continued wastewater utility service to both IBRC and GR&S; the need for tank replacement; the failure of the existing escrow established by the Commission's May 28, 2004 Order in the Frit Environmental, Inc., abandonment proceeding, Docket No. W-965, Sub 3; and the status of the improvements necessary to bring the system into compliance with Department of Environment and Natural Resources (DENR) requirements. The Commission further believes that the Sub 1 Proceeding provided significant factual background for the issues in this general rate case. The Commission concludes that these attorneys fees were incurred within the test year period; were reasonable, prudent, and necessary in order for Enviracon to present to the Commission the facts and issues relating to the tank collapse and subsequent expenses, claims, and tank-replacement related costs; and should be recovered from customers as an extraordinary expense.

The Commission believes that GR&S' assertion that the Sub 1 Proceeding, was solely an abandonment proceeding by Enviracon rests on a misunderstanding. Although, in its Docket No. W-1236, Sub 1 application, Enviracon included an alternative prayer for relief seeking abandonment, the primary issues in the Sub 1 Proceeding were the tank collapse, the environmental cleanup, the pumping and hauling, and the necessity for expeditious tank replacement. Enviracon, in its Docket No. W-1236, Sub 1 Proposed Order filed January 13, 2006, did not request that the Commission approve the abandonment.

Based upon the foregoing, the Commission finds and concludes that the $65,256 in legal fees should be included in the extraordinary expenses relating to the WWTP tank collapse, environmental cleanup, pump and haul, and related issues. These legal fees were primarily incurred in the Sub 1 Proceeding, and the Commission takes judicial notice of the Commission Order dated April 7, 2006, in that proceeding.[1]

SUMMARY CONCLUSION

Based upon the foregoing, the Commission concludes that the appropriate level of extraordinary tank collapse/clean-up/pump-and-haul expenses to be recovered through a temporary rate increment is $456,612, which includes the following:

[1] The Commission Panel who heard the Sub 1 Proceeding is also the same Commission Panel that has decided this current general rate case proceeding.

WATER AND SEWER – RATE INCREASE

VENDOR	ALLOWED
Hepaco	$120,003
Barnes Environmental, Inc.	33,578
Lewis Farms and Liquid Waste	20,961
Town of Morehead City	20,115
Stroud Engineering, PA	1,391
Terracon	21,504
OBI Mechanical	85,157
Mobile Home Park Residents	50,000
Town of Atlantic Beach	621
Unlimited Hauling, Inc.	6,400
Rountree & Boyette, LLP	8,110
Bode, Call & Stroupe, LLP	57,146
DENR	1,090
Enviracon Beach Operations	7,922
Enviracon Utilities	22,614
TOTAL	**$456,612**

Consequently, the Commission concludes that the appropriate level of gross revenues, including gross receipts taxes and regulatory fees, necessary to allow for the recovery of extraordinary tank collapse/clean-up/pump-and-haul expenses through a temporary rate increment is $486,378.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 33

The evidence for this finding of fact is found in the application, the testimony of Enviracon witness Chapman and Public Staff witness Tweed, and the entire record of this proceeding.

The application sought recovery of the extraordinary expenses associated with the cleanup of the wastewater spill resulting from the collapse of a wall of the WWTP tank through amortizing the expense over a two-year period. In the Commission's May 31, 2006 Order Establishing General Rate Case, Suspending Rates and Granting Interim Rates in this docket, the issue of the appropriateness of amortizing extraordinary expenses was addressed. The Commission concluded in said Order that the amortization of these expenses was similar to the established practice of amortizing storm restoration costs.

None of the witnesses in the hearing in this docket contested the proposed two-year amortization period. The Commission concludes that it is appropriate to amortize the extraordinary expenses over a 24-month period beginning when the interim rates were approved in this docket on May 31, 2006.

The Public Staff represented in its Proposed Order that Enviracon will have collected $108,895 for service provided through December 2006 under interim rates which went into effect on May 31, 2006. The Commission finds that the Public Staff should file, for Commission review and approval, revised temporary rates for the balance of the extraordinary tank collapse amortization period reflecting the Commission-approved extraordinary tank collapse expenses, the payments that have been made by both GR&S and IBRC, and the remaining amortization months, allocated 60% and 40% between the two customers, respectively.

The Commission concludes that it is appropriate to amortize the unamortized balance of the Commission-approved tank collapse expenses found reasonable herein, over a 16-month period beginning February 2007.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34 THROUGH 37

The evidence supporting these findings of fact is contained in the testimony of Public Staff witness Henry, Enviracon witness Chapman, and GR&S witness Hering. The following table summarizes the amounts that the Company and the Public Staff contend are the proper levels of ongoing depreciation, payroll taxes, regulatory fees, and gross receipts taxes to be used in this proceeding:

Item	Company	Public Staff	Difference
Depreciation expense	$ 0	$ 1,464	$ 1,464
Payroll taxes	1,162	1,162	0
Regulatory fee	105	102	(3)
Gross receipts tax	5,123	5,123	0
Total	$ 6,390	$ 7,851	$ 1,461

As shown in the preceding table, the Public Staff and the Company agree on the levels of property taxes, payroll taxes, and gross receipts taxes. Also, there is a rounding difference of three dollars between the levels of regulatory fee expense presented by the Company and the Public Staff. The Company has accepted, for purposes of this proceeding, all the Public Staff's adjustments and the Public Staff's recommended rates. GR&S and IBRC did not contest the amounts for depreciation and taxes presented by the Company or the Public Staff. Therefore, the Commission concludes that the levels of depreciation, taxes, and regulatory fees recommended by the Public Staff are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38 THROUGH 40

MARGIN ON EXPENSES

The evidence for these findings of fact is contained in the testimony of GR&S witness Hering and Public Staff witness Craig.

Witness Craig recommended that the Company be granted an 8.5% margin on operating revenue deductions requiring a return. His recommendation would produce operating ratios of 92.79%, (including taxes) and 92.17% (excluding taxes) for the sewer utility service. Witness Craig testified that he derived a margin on expenses by identifying a risk-free rate and adding a 3.0% risk factor, thus yielding the Public Staff's recommended margin on expenses of 8.5%. Witness Craig further testified that his methodology is consistent with the method presented by the Public Staff and adopted by the Commission in Docket No. W-173, Sub 14, a general rate case application by Montclair Water Company, Inc.

Witness Hering testified that GR&S agreed with witness Craig's recommendation of an 8.5% margin on operating revenue deductions requiring a return. Consequently, witness Hering stated that he used an 8.5% margin on expenses when calculating the Company's revenue requirement.

Witness Craig recommended using the operating ratio method for determining the margin on operating revenue deductions requiring a return in this proceeding pursuant to G.S. 62-133.1(a). The Applicant, the Public Staff, and GR&S all used the operating ratio method in determining the Applicant's revenue requirement.

With respect to the matter of allowing a margin on extraordinary tank collapse related expenses, Public Staff witness Henry stated there should be no return or margin on the expenses related to the extraordinary tank collapse. Enviracon witness Chapman testified that Enviracon agreed to this Public Staff recommendation. GR&S witness Hering also testified there should not be a return on these extraordinary expenses.

The Commission concludes that it is reasonable and appropriate that there should be no margin allowed on the extraordinary tank collapse related expenses.

The Commission finds that the operating ratio methodology as described in G.S. 62-133.1(a) is reasonable for use in this proceeding. The Commission concludes that an 8.5% margin on the ongoing operating revenue deductions requiring a return is reasonable for use in this proceeding. This margin is based upon an evaluation of relevant historical and prospective interest rate information and has been approved by the Commission in other recent cases.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 41 AND 42

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Tweed and GR&S witness Frazzini and in the entire record of this proceeding.

Public Staff witness Tweed initially recommended that rates be set at $14,482 per month for GR&S and $9,654 per month for IBRC as long as the extraordinary expenses were being amortized. These numbers were later revised in the Public Staff's Proposed Order to $20,303 for GR&S and $13,536 for IBRC, as previously discussed in this Order. At the end of the amortization period, witness Tweed recommended that Enviracon be required to file a general rate case to eliminate the extraordinary expense portion of the rates or, in the alternative, that the rates be reduced to $4,910 per month for GR&S and $3,273 per month for IBRC at the end of the amortization period without the need for filing a general rate case. The Public Staff revised those numbers to $5,289 for GR&S and $3,526 for IBRC in its Proposed Order to reflect updating of the previously estimated rate case expense. Witness Tweed further testified that, if the Commission orders the rates to be reduced without a general rate case, the Public Staff could file a report with the Commission, at the appropriate time, recommending a rate reduction to become effective on an appropriate specified date.

Regarding the matter of adjusting rates at the conclusion of the amortization period, GR&S witness Frazzini requested that the Commission adopt the second option proposed by the Public Staff, with a sunset provision on the amortized extraordinary expenses, to avoid having all parties return to the Commission for further proceedings.

Further, GR&S requested that, to the extent the Commission adopts the base rates recommended by the Public Staff, the Commission should recognize that the customers have paid higher interim base rates since the interim rates were approved in May 2006, and provide for appropriate recognition of such overpayments.

Consistent with our prior rulings herein concerning the appropriate level of amortization of extraordinary expenses, the Commission finds and concludes that the Public Staff should file with the Commission revised temporary rates for the balance of the extraordinary tank collapse amortization period reflecting the Commission-approved extraordinary tank collapse expenses and the payments that have already been made by both GR&S and IBRC, based on the remaining months in the amortization period. Whereupon, the Commission will review the Public Staff's filing and will then be able to establish the temporary rates to be in effect over the remaining amortization period or until further order of the Commission.

Upon conclusion of the amortization period related to the extraordinary expense portion of the rates, Enviracon should file a report with the Commission within seven days thereafter. The Public Staff should then review said report and make the appropriate recommendation to the Commission based upon its findings. As set forth in our prior rulings herein, the Commission has agreed with the Public Staff's recommendations concerning the Company's ongoing level of costs to be used in determining base rates; in this instance, the base rates exclude the amortization of extraordinary expenses. Accordingly, the Commission concludes that, once the Public Staff has ultimately reviewed and concluded that the final Commission-approved extraordinary expense portion of the rates have been properly collected by Enviracon, the Company's ongoing rates should be reduced to $5,289 per month for GR&S and $3,526 per month for IBRC, as proposed by the Public Staff.

With respect to the assertion by GR&S that there will be an overpayment under the interim base rates if the Commission adopts the base rates recommended by the Public Staff, the Commission is uncertain, at this time, as to the actual rates that will be in effect during the remaining amortization period. Consequently, the Commission will need to resolve this issue by a further order when such issue is ripe for decision. However, to the extent that the rates ultimately approved by the Commission, for the remaining months of the two-year amortization period, are greater than $14,745 per month for GR&S and $9,830 per month for IBRC, the Commission would conclude that there would have been no overpayment by customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 43

The following schedules summarize the gross revenue and rate of return that the Company should have a reasonable opportunity to achieve for its ongoing operations excluding the amortization of extraordinary expenses, based upon the increase approved in this Order. These schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions reached by the Commission in this Order.

SCHEDULE I

ENVIRACON UTILITIES, INC.
DOCKET NO. W-1236, SUB 2
STATEMENT OF ONGOING OPERATING INCOME FOR RETURN
For The Twelve Months Ended December 31, 2005

Item	Present Rates	Increase Approved	After Approved Increase
Operating revenues:			
Service revenues	$ 85,380	$ 20,393	$105,773
Miscellaneous revenues	0	0	0
Uncollectible	0	0	0
Total operating revenues	85,380	20,393	105,773
Operating revenue deductions:			
O&M expenses	87,042	0	87,042
Depreciation	1,464	0	1,464
Property taxes	0	0	0
Payroll taxes	1,162	0	1,162
Regulatory fees	102	25	127
Gross receipts tax	5,123	1,223	6,346
State income tax	0	665	665
Federal income tax	0	1,345	1,345
Total oper. revenue deductions	94,893	3,258	98,151
Net operating income for return	$ (9,513)	$ 17,135	$ 7,622
Operating revenue deductions requiring a return	$ 89,668		$ 89,668
Margin	(10.61%)		8.50%

SCHEDULE II

ENVIRACON UTILITIES, INC.
DOCKET NO. W-1236, SUB 2
STATEMENT OF ORIGINAL COST RATE BASE
For The Twelve Months Ended December 31, 2005

Item	Amount
Plant in service	$ 7,321
Accumulated depreciation	(1,464)
Cash working capital	10,880
Average tax accruals	(1,048)
Original cost rate base	$ 15,689

IT IS THEREFORE, ORDERED as follows:

1. That Enviracon is hereby granted an increase in its sewer utility rates as reflected in this Order.

2. That a claim settlement fund in the amount of $50,000, collected through a temporary rate increment over a two-year period beginning when the interim rates were approved in this docket on May 31, 2006, shall be established to fund the payment of certain mobile home park damage claims. That Enviracon's shareholders shall contribute 15% of the settlement amount of each claim paid to the claimant, with no more than 85% of the agreed upon settlement amount to be paid from the claim settlement fund.

3. That, on or before Monday, March 26, 2007, the Public Staff shall file, for Commission review and approval, revised temporary rates for the balance of the extraordinary tank collapse amortization period reflecting the Commission-approved extraordinary tank collapse expenses, the payments that have been made by both GR&S and IBRC, and the remaining amortization months, allocated 60% and 40% between the two customers, respectively.

4. That Enviracon's Schedule of Rates for sewer utility service shall be provided by further order of the Commission.

5. That Enviracon shall meet with its two customers on or before Friday, April 20, 2007, to provide an opportunity for all parties to participate in the formulation of a prospective solution to Enviracon's future insurance needs.

6. That Enviracon shall file a report with the Commission on or before Monday, May 21, 2007, detailing its specific activities involved in, and the anticipated costs of, obtaining insurance coverage for the wastewater system, including the status of such efforts. If Enviracon enters into a binding insurance agreement prior to the filing of said report, then a list of the types of insurance coverage obtained, the level of coverage obtained, the associated premiums, and the term of coverage shall be included in the report filed with the Commission.

7. That Enviracon shall file a final accounting with the Commission detailing the final amount paid or to be paid to each claimant. Such accounting shall be filed with the Commission every six months beginning on Friday, September 21, 2007, or sooner in the event that all claims have been settled or the settlement claims have exceeded $50,000. Upon review of the final claim amounts, if necessary, a further order by the Commission, setting forth any adjustment or true-up related to the temporary rate increment shall be issued.

8. That, since the only Enviracon customers are both intervenors in this proceeding, the issuance of this Order shall serve as proper notice to the customers.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of March, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

fh032107.01

DOCKET NO. W-218, SUB 245
DOCKET W-1101, SUB 3

In the Matter of		
Application by Aqua North Carolina, Inc., Post Office Drawer 4889, Cary, North Carolina 27519, and North Chatham Water & Sewer Company, LLC, 16740 Birkdale Commons Parkway, Suite 306, Huntersville, North Carolina 28078, for Authority to Transfer the Water and Sewer Assets and Franchises for Cole Park Plaza Shopping Center, Chatham Crossing Shopping Center, and Cole Place Development Subdivision in Chatham County, North Carolina, and to Increase Rates	)	RECOMMENDED ORDER GRANTING TRANSFER, GRANTING RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD IN: Courtroom, Chatham County Courthouse, 12 East Street, Pittsboro, North Carolina, on February 22, 2007, at 7:00 p.m.

BEFORE: Ronald D. Brown, Hearing Examiner

APPEARANCES:

For: Aqua North Carolina, Inc.

Laurence A. Cobb, Cobb Law Firm, PLLC, 108 Prestwick Place, Cary, North Carolina 27511

For: North Chatham Water and Sewer, LLC

No Attorney of Record

For the Using and Consuming Public:

James D. Little, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BROWN, HEARING EXAMINER: Aqua North Carolina, Inc. (Aqua or Company), filed an application on September 15, 2006, to transfer the water and sewer assets and franchises for Cole Park Plaza Shopping Center, Chatham Crossing Shopping Center and Cole Place Development Subdivision in Chatham County, North Carolina, from North Chatham Water and Sewer Company, LLC (NCWSC), and to increase rates. Attached to the application as an exhibit was the Assets Purchase Agreement dated August 11, 2006, between Aqua and NCWSC (Purchase Agreement). On September 27, 2006, and November 29, 2006, the Company filed amendments to its application. On December 19, 2006, the Commission issued an Order Establishing General Rate Case, Scheduling Hearing, and Requiring Customer Notice. Aqua filed its Certificate of Service on December 27, 2006.

In order to accommodate the schedules of the parties, the Commission issued an Order Rescheduling Hearing on January 12, 2007, changing the hearing date and location. Aqua filed its Certificate of Service on January 23, 2007.

On February 2, 2007, the Public Staff filed the testimony and exhibits of A. Denise Barnett, Staff Accountant, and David C. Furr, Utilities Engineer. On February 19, 2007, the Company filed the testimony of Neil R. Phillips, President of Aqua.

On February 22, 2007, a public hearing was held in Pittsboro, North Carolina. There were no public witnesses. The Company offered the testimony of Neil R. Phillips and the Public Staff offered the testimony of A. Denise Barnett and David C. Furr. After witness Furr's testimony, the Hearing Examiner allowed Michael K. Schutrum to testify. Witness Schutrum stated that he represented NCWSC and Glenwood Development Company, LLC (Glenwood).

On April 4, 2007, Aqua filed a copy of a Water and Sewer Capacity and Service Agreement dated March 30, 2007, as a late-filed exhibit.

On April 9, 2007, Aqua and the Public Staff filed their respective Proposed Recommended Orders.

On June 19, 2007, Hearing Examiner Brown issued a Recommended Order Granting Transfer, Granting Rate Increase, and Requiring Customer Notice.

On June 29, 2007, Aqua filed a motion for extension of time to file exceptions to the June 19, 2007 Recommended Order stating that the Company needed additional time to complete its exceptions because of recent changes in Aqua's legal counsel and local management. Aqua stated that the Public Staff and NCWSC did not object to the proposed extension.

On July 3, 2007, the Commission issued an Order Granting Extension of Time to File Exceptions.

On July 25, 2007, Aqua filed Amendment No. 2 to the Purchase Agreement.

On August 3, 2007, attorneys for the Public Staff (James D. Little), Aqua (C. Blythe Clifford), and NCWSC (Christopher J. Ayers) filed, in lieu of exceptions to Hearing Examiner Ron Brown's June 19, 2007 Recommended Order, a Joint Proposed Recommended Order and requested that such Joint Proposed Recommended Order be substituted for the June 19, 2007 Recommended Order. In their filing, the parties remarked that the Joint Proposed Recommended Order reflected agreement on certain issues raised in the June 19, 2007 Recommended Order and reflected modifications now necessary to that Recommended Order due to the filing on July 25, 2007, of a second amendment to the Purchase Agreement entered into on July 23, 2007, between Aqua, NCWSC, and Glenwood. In addition, the parties requested that the Commission hold the June 19, 2007 Recommended Order in abeyance until the Commission has an opportunity to review the Joint Proposed Recommended Order.

On August 6, 2007, the Commission issued an Order Holding Recommended Order in Abeyance.

Based upon the foregoing, the verified application, the evidence and exhibits presented at the hearing, and the entire record on this proceeding, the Hearing Examiner makes the following

FINDINGS OF FACT

1. NCWSC is a duly franchised public utility as defined by G.S. 62-3(23). NCWSC provides water and sewer utility service for Cole Park Plaza Shopping Center, Chatham Crossing Shopping Center, and Cole Place Development Subdivision in Chatham County, North Carolina.

2. Aqua is a corporation duly organized under the laws of and is authorized to do business in the State of North Carolina.

3. As of December 31, 2005, NCWSC provided water service to 50 residential customers and 54 commercial customers.

4. As of December 31, 2005, NCWSC provided sewer service to 50 residential customers and 55 commercial customers.

5. On August 11, 2006, Aqua and NCWSC executed the Purchase Agreement (Purchase Agreement) under which Aqua will acquire the NCWSC water and sewer assets for $200,000. On July 23, 2007, Aqua, NCWSC, and Glenwood executed a second amendment to the Purchase Agreement revising the purchase price to $87,296.

6. The present and proposed service rates are as follows:

Service	Present Rates	Proposed Rates
Water Utility Service:		
Base charge, zero usage		
¾" meter	$ 12.75	$ 12.75
1" meter	$ 35.00	$ 35.00
1 ½" meter	$ 75.00	$ 75.00
2" meter	$100.00	$100.00
3" meter	$135.00	$135.00
4" meter	$225.00	$225.00
Usage charge, per 1,000 gallons		
All usage	$ 1.90	NA
0 - 5,000 gallons	NA	$ 7.00
5,000 – 8,000 gallons	NA	$ 8.50
over 8,000 gallons	NA	$ 10.00
Sewer Utility Service:		
Residential Users:		
Flat Rate	$ 26.00	$ 26.00
Non-Residential Users:	236% of water bill	NA

WATER AND SEWER – SALE/TRANSFER

Base charge, zero usage		
¾" meter	NA	$ 30.09
1" meter	NA	$ 82.60
1 ½" meter	NA	$177.00
2" meter	NA	$236.00
3" meter	NA	$318.60
4" meter	NA	$531.00
Usage charge, per 1,000 gallons	NA	$ 4.484

7. Present and proposed new connection, reconnection, account, and returned check charges are as follows:

<u>NCWSC's Present Charges:</u>

Charge for New Connections:	
Customer inside franchised service area	Actual Cost
Customer outside franchised service area	Actual Cost
Reconnection Charges:	
If water service is cut off by utility for good cause	$ 6.00
If water service discontinued at customer's request	$ 2.00
If sewer service is cut off by utility for good cause	$15.00
New Account Charge:	$10.00
Returned Check Charge:	$10.00

<u>Aqua's Proposed Charges:</u>

Charge for New Connections:	
Customer inside franchised service area	Actual Cost
Customer outside franchised service area	Actual Cost
Reconnection Charges:	
If water or sewer service cut off by utility for good cause	$30.00
If water or sewer service discontinued at customer's request	$ 5.00
If sewer service is cut off by utility by discontinuing water	None
If sewer service is cut off for any other reasons than above	Actual Cost
New Account Charge:	$15.00
Returned Check Charge:	$20.00

8. NCWSC has switched to purchased water and the wells have been abandoned. Since these wells have been abandoned, and are no longer in service, the costs associated with these wells should not be included in the net plant in service acquired by Aqua.

9. Chatham Crossing, a shopping center that is currently receiving service, paid $50,000 of contributions in aid of construction (CIAC) to NCWSC in 1998. The total amount of this CIAC should be deducted from used and useful plant since Chatham Crossing was paying for the plant capacity it is using, not plant capacity for future customers.

10. The wastewater treatment plant was built and began operation in 1998, and over the last nine years, the value of the plant has deteriorated due to wear and tear.

11. When making an adjustment to remove excess capacity from rate base, it is appropriate to remove both the plant costs and accumulated depreciation associated with the excess capacity.

12. Under the August 11, 2006 Purchase Agreement, 20,000 gallons per day (gpd) of capacity is reserved exclusively for NCWSC/Glenwood and NCWSC/Glenwood can sell this capacity to other developers.

13. On March 30, 2007, NCWSC, Glenwood, Aqua, and IS Development Company, LLC (IS), entered into a Water and Sewer Capacity and Service Agreement (IS Agreement), under which 12,000 of the 20,000 gpd reserved capacity was sold to IS for $96,000.

14. The cost of the wastewater treatment plant is a utility asset; and any monies collected to offset this cost are CIAC. Therefore, the $96,000 paid by IS for the 12,000 gpd of treatment plant capacity, regardless of whether it was paid directly to NCWSC or indirectly through its affiliated company, Glenwood, is CIAC, and reduces the cost of the net plant in service being acquired by Aqua.

15. On July 25, 2007, Aqua filed a second amendment to the Purchase Agreement. Under this amendment, NCWSC/Glenwood relinquished its prior claim to the remaining 8,000 gpd of reserved capacity. Since this capacity is no longer reserved by NCWSC/Glenwood, it is appropriate to include the cost of this capacity in the net plant in service acquired.

16. The net book value of the assets being acquired is $87,296, consisting of plant in service of $376,165 less accumulated depreciation of $157,872 and CIAC, net of amortization, of $130,997.

17. Since the amended purchase price of $87,296 is equal to the net book value of the assets being acquired, there is no acquisition adjustment to be addressed in this case.

18. Aqua has the technical, managerial, and financial capacity to own and operate the NCWSC water and sewer systems.

19. The rates and charges proposed by Aqua are reasonable and should be approved.

20. The appropriate bonds for these systems for Aqua are $10,000 for the water system, and $10,000 for the sewer system, for a total of $20,000.

21. The transfer of the franchise assets of NCWSC to Aqua should be approved.

WATER AND SEWER – SALE/TRANSFER

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 - 7

The evidence supporting these findings of fact is contained in the application and in the testimony of Public Staff witness Furr. These findings are primarily jurisdictional and informational and are not contested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 - 17

The evidence supporting these findings of fact is contained in the application and the testimony of Public Staff witnesses Furr and Barnett, Company witness Phillips and NCWSC witness Schutrum. The parties initially disagreed on the level of net plant in service of the assets being acquired, as shown hereinbelow; however, in the August 3, 2007 Joint Proposed Recommended Order, the Company and NCWSC agreed to accept the Public Staff's positions in order to expedite Commission approval of their September 15, 2006 Application for Transfer and Rate Increase.

Item	Company	Public Staff	Difference
Plant in service acquired	$252,517	$252,517	$ 0
Accumulated depreciation acquired	(102,230)	(120,783)	(18,553)
CIAC acquired	(30,000)	(50,000)	(20,000)
Accumulated amort. of CIAC acquired	15,003	15,003	0
Net plant in service acquired	$135,290	$ 96,737	$ (38,553)

Based on the record in this case, the initial differences between the parties concerning the level of net plant acquired pertained to the following:

(1) The Company questioned how the Public Staff handled $34,465 of plant items that were reclassified from sewer to water operations in the last rate case.

(2) The Company disagreed with the treatment of $50,000 of CIAC received by NCWSC.

(3) The Company disagreed with the calculation of accumulated depreciation on the plant costs that were not included in the last rate case due to excess capacity.

(4) At the hearing, the Company's attorney questioned whether the Public Staff had a $300 discrepancy in its calculation of total sewer plant in service.

(5) The parties disagreed on how the 20,000 gpd of reserved capacity should be handled in this case.

Reclassified Plant Items

Company witness Phillips testified that in the last rate case, Docket No. W-1101, Sub 2, $34,465 of plant items was reclassified from sewer to water operations. Witness Phillips indicated that the Company had not been able to determine how these plant items were treated in this case, and asked that the Public Staff clarify this matter. At the hearing, Public Staff witness Barnett testified that the $34,465 consisted of legal fees and three well related items, which were a draw down test, a well video, and a pump. Witness Barnett testified that she included the legal fees, which totaled $26,026, but she did not include the well related items, since the two wells that were previously in operation are no longer used. Public Staff witness Furr testified that due to problems with water quality in one well, and to meet minimum water source requirements, NCWSC has abandoned both wells, and is now purchasing water from Chatham County. Therefore, Public Staff witness Barnett did not include the well related items.

In the August 3, 2007 Joint Proposed Recommended Order, Aqua and NCWSC agreed to accept the Public Staff's position on reclassified plant items in order to expedite Commission approval of their September 15, 2006 Application for Transfer and Rate Increase.

The Hearing Examiner concludes that the $34,465 of plant items reclassified from sewer to water operations in the last rate case, which consists of legal fees and well costs, have been appropriately handled in the Public Staff's calculation of net plant acquired. The Hearing Examiner is of the opinion that it is appropriate to remove the plant costs related to the wells, which are no longer in service. Public Staff witness Barnett testified that these well costs totaled to a net plant amount of $3,500, which included $10,302 of water plant minus $6,802 of accumulated depreciation. The customers should not be required to pay for the cost of wells that are no longer used, in addition to paying for the cost of purchased water. As to the legal fees, although some question was raised on cross examination concerning the allocation of these fees between water and sewer operations, in the last rate case, the Commission accepted the allocation of 50% of the legal fees to sewer operations, which resulted in the remaining amount, 50%, being assigned to water operations.

$50,000 of CIAC

In her prefiled testimony, Public Staff witness Barnett deducted $50,000 in CIAC based on documentation presented in Docket No. W-1101, Sub 2, the previous rate case application by NCWSC. Company witness Phillips disagreed with the Public Staff's treatment of this CIAC in NCWSC's last rate case, since the Public Staff deducted 100% of this CIAC from the cost of the plant, even though 60% of the plant was excess capacity in that case. Witness Phillips testified that since 60% of the plant capacity is now in service, only $30,000 should be deducted as CIAC. Witness Phillips further testified that at the time Chatham Crossing contributed the CIAC, it consisted of the same principals as NCWSC.

Public Staff witness Barnett testified that when the person who paid the CIAC is using the plant, he should receive the benefit of that payment. In this case, the $50,000 was deducted from plant, because the service area for which the CIAC was received is being served. Witness Barnett testified that her treatment of the CIAC in this case is consistent with the Commission's ruling on a similar issue in Docket No. W-354, Sub 111, a general rate case application by

Carolina Water Service, Inc. of North Carolina. Witness Barnett also testified that Chatham Crossing paid the $50,000 for service to its shopping center, which is receiving service, and that this payment was similar to a tap fee.

In the Final Order Assessing Rate of Return Penalty and Granting Partial Rate Increase issued on October 12, 1992 in Docket No. W-354, Sub 111, the Commission addressed the issue of how to handle tap fees, a form of CIAC, in the calculation of excess capacity. In that case, the Commission concluded:

> The Commission agrees with the Public Staff's position on this issue. When a customer pays a tap fee/plant impact fee, he is paying to offset the cost of <u>plant he uses</u>. It would contradict the very purpose of tap fees and plant impact fees if they were deemed to be paid by a customer on behalf of some potential future customer rather than on his own behalf. Therefore, such fees should be deducted from the used and useful portion of the utility plant cost, not from utility plant cost prior to excess capacity adjustments.
>
> The issue of prepaid tap fees from the developer was also an issue of disagreement between the parties. The Public Staff treats these fees in the same manner as customer tap fees. With respect to the Cabarrus Woods elevated storage tank and sewer treatment plant, the Public Staff has deducted these prepaid tap fees after making its percentage utilization adjustment.
>
> The Commission concludes that the same logic applies to prepaid tap fees and plant impact fees from the developer because the purpose of the payment -- not the source of the payment -- is most relevant. Customers would have paid these tap fees and plant impact fees except that the developer prepaid these fees for them. The prepaid fees still go to offset the cost of plant that is used and useful to those customers. Consistent with this method, the Commission has deducted developer prepaid tap/plant fees in the percentage utilization adjustment subsequent to any disallowance.

82 <u>Report of the NCUC Orders and Decisions</u> 387, 430 (1992).

In the August 3, 2007 Joint Proposed Recommended Order, Aqua and NCWSC agreed to accept the Public Staff's position regarding the treatment of the $50,000 of CIAC received by NCWSC in order to expedite Commission approval of their September 15, 2006 Application for Transfer and Rate Increase.

As cited above, the purpose of a CIAC payment is most relevant in determining how to handle the CIAC in the calculation of excess capacity. If the CIAC was paid by a customer or developer for a specific lot or service area that is currently receiving service, then the total amount of the CIAC should be deducted from used and useful plant after the adjustment to remove excess capacity. This is necessary since the customer or developer is paying for plant that he used, not for plant to serve future customers. Since Chatham Crossing, a shopping center, is currently served by NCWSC, the total amount of CIAC paid by Chatham Crossing of $50,000 should be deducted from used and useful plant in service. The fact that the principals of

Chatham Crossing and NCWSC were the same parties at the time of the contribution is not relevant, and does not mitigate the purpose for which the CIAC was contributed. Therefore, the Hearing Examiner is of the opinion that the entire $50,000 of CIAC should be removed when computing net plant acquired.

In addition, just as a matter of clarification, the Hearing Examiner observes that Company witness Phillips stated in his prefiled testimony that if only $30,000 were deducted as CIAC that, "[t]his would result in an increase of $20,000 in the net plant in service to $116,737 using Accountant Barnett's figures". The Hearing Examiner notes that the Company has an error in its calculation to decrease the amount of CIAC deducted from net plant in service since the Company adjusted CIAC from $50,000 to $30,000, but failed to also adjust the associated accumulated amortization by $6,001, to reflect the proposed $20,000 decrease in CIAC.

Accumulated Depreciation on Excess Capacity

In its calculation of net plant acquired, the Public Staff included accumulated depreciation from the year the plant was built, after the removal of the excess capacity retained by the seller. Company witness Phillips testified that in the last rate case, only 40% of the sewer treatment plant was included in rates, and therefore, it is the Company's contention that only 40% of the wastewater treatment plant should be depreciated because that is all that has been in rate base for the nine years since the plant was built.

Public Staff witness Barnett testified that depreciation expense is the decrease in the value of the property. In this case, the wastewater treatment plant has been in service for nine years, and it has deteriorated during that time. Witness Barnett further testified that the treatment plant is not a new system, and she cannot include it in rate base as a new system when it is not. Public Staff witness Furr testified that even though all of the plant has not been included in rates, the plant is still depreciating in value, since there is wear and tear on the plant. For example, the blower is running whether it's treating 40,000 gpd or 50,000 gpd. Witness Furr testified that the wear and tear on the sewer plant is for the most part unchanged by the amount of effluent flowing through it, whether it's at 40% capacity or 100% capacity.

In the August 3, 2007 Joint Proposed Recommended Order, Aqua and NCWSC agreed to accept the Public Staff's position regarding the calculation of accumulated depreciation on the plant costs that were not included in the last rate case due to excess capacity in order to expedite Commission approval of their September 15, 2006 Application for Transfer and Rate Increase.

The Hearing Examiner is of the opinion that accumulated depreciation of the entire plant must be deducted regardless of the level of excess capacity. The fact that an adjustment was made to remove a percentage of the wastewater treatment plant in the last rate case due to excess capacity does not change the fact that the wastewater treatment plant was built and began operation in 1998, and over the last nine years, the value of that plant has deteriorated due to wear and tear. As testified by Public Staff witness Furr, the wear and tear of a wastewater treatment plant is for the most part unchanged by the amount of effluent running through it.

The Company's argument that accumulated depreciation should only be included on 40% of the treatment plant, which is the used and useful percentage from the last rate case, is not valid. In the first place, the treatment plant, whether or not included 100% in rates, was installed in 1998, and its value has deteriorated over time. When an excess capacity adjustment is made, a percentage of the plant, along with the associated accumulated depreciation, is disallowed. The fact that, for presentation purposes, the Public Staff only showed the accumulated deprecation for the used and useful portion of the plant, instead of showing the total plant costs and the total accumulated depreciation and then reducing both amounts by the excess capacity percentage, does not change the fact that the plant in total has deteriorated, and its useful life today is not the same as a brand new plant. These are just two methods of arriving at the same point. In the second place, customers have been added over the years since the last rate case, which was based on a test year ended December 31, 1999, and as these customers were added, they started receiving service, using the treatment plant, and paying rates.

Possible $300 Discrepancy

In her prefiled testimony, Public Staff witness Barnett listed a total amount for sewer plant, before Public Staff adjustments, of $337,045 on Barnett Exhibit I, Schedule 1-1, Line 17, Column (a). At the hearing, the Company presented Aqua Cross-Examination Exhibit No. 1, which listed a total sewer plant in service of $336,745. In presenting this exhibit, Company attorney Cobb pointed out that when he added the individual sewer plant items up he came up with $336,745, so either he kept missing $300 or the Public Staff had a $300 discrepancy. The Hearing Examiner has checked the computation of the individual wastewater treatment plant items listed on both Barnett Exhibit I, Schedule 1-1, and on Aqua Cross-Examination Exhibit No. 1, and has determined that the wastewater treatment plant items, before Public Staff adjustments, total to $337,045, the amount listed by the Public Staff. Therefore, the Hearing Examiner concludes that there is no discrepancy in the Public Staff's amount of total sewer plant costs before Public Staff adjustments (it is noted that vertically adjacent keys on a calculator [like 1 and 4 or 6 and 9] differ by 3).

Reserved Capacity

Public Staff witness Furr testified in prefiled testimony that the Purchase Agreement is a three-way agreement between NCWSC, Aqua, and Glenwood. The Purchase Agreement reserves 20,000 gpd of the wastewater treatment plant capacity exclusively for Glenwood for a period of ten years. The Purchase Agreement also gives Glenwood and its successors and assigns the right to sell and assign all or any portion of the capacity. Witness Furr testified that this represents 40% of the treatment capacity, and since Aqua is not obtaining control of this portion of the facility, 40% of the treatment plant and engineering design fees should be excluded from plant in service.

Company witness Phillips testified that NCWSC/Glenwood had to build a 50,000 gpd sewage treatment plant to acquire the existing franchise and the penalty which NCWSC/Glenwood had to pay was that it has had no return on 60% of its investment other than the rates paid by new customers as some of the excess capacity was placed in service. Witness Phillips further testified that when NCWSC negotiated the sale of these systems, it wanted to be assured that the remaining excess capacity for which it had paid in full would be available either for its further expansion or for expansion by developers it selected who would be willing to compensate them for some of the expense incurred in the original building of the plant.

NCWSC/Glenwood was not willing to allow Aqua to furnish sewer service to another developer through the use of this excess capacity without the developer making any contribution toward the cost of the sewage treatment plant to NCWSC/Glenwood. Witness Phillips also testified that the Purchase Agreement does not allow NCWSC/Glenwood to retain any control over the plant as the Public Staff has contended, nor does it allow NCWSC/Glenwood to somehow pick up and deliver a given number of gallons per day to a third party so as to deprive Aqua of the use of that capacity.

The Purchase Agreement entered into by NCWSC, Glenwood, and Aqua on August 11, 2006 states the following:

(i) As additional consideration for sale of the System Assets to Buyer, for a period of ten (10) years commencing on the Closing Date and ending on the date which is ten (10) years after the Closing Date (the "10-Year Connection Period"), Buyer, its successors and assigns and successors in interest to title to the System Assets (or any portion thereof) shall exclusively reserve for the benefit of Glenwood Development, and its successors and assigns wastewater capacity in the amount of Twenty Thousand (20,000) gallons per day (the "Wastewater Capacity Allocation"), together with right of Glenwood or its successors or assigns, if so desired, to use the water service provided by Buyer, its successors or assigns, to be used in connection with property located in the following areas:

(A) The development, use and operation of properties described and shown on the map attached as <u>ATTACHMENT 1</u> which is incorporated herein by reference thereto which also includes the properties located in the Service Area (the "Proximate Property Service Area"); and

(B) Subject to the approval of the NCUC, the development, use and operation of any other property from time to time hereafter designated in writing by Glenwood Development with such designation to be recorded in the office of the Register of Deeds of Chatham County, North Carolina (the "Additional Future Service Area"; and the Proximate Property Service Area and the Additional Future Service Area are hereinafter sometimes collectively referred to as the "Future Service Area").

The Purchase Agreement further states:

(vii) The parties hereto agree that Seller (or Glenwood Development) shall have the right to sell and allocate wastewater capacity in the amount of up to Twenty Thousand (20,000) gallons per day between the date of this Agreement and the Closing Date in the same manner as provided for above; provided, however, (a) the Wastewater Capacity Allocation under this Agreement shall be reduced by the number of gallons per day of wastewater capacity so sold and allocated by Seller (or Glenwood Development) prior to Closing (b) the Glenwood Development Allocation Agreement to be signed at Closing shall be amended to reflect the correct amount of the remaining Wastewater Capacity Allocation after such reduction.

On March 30, 2007, NCWSC, Glenwood, Aqua, and IS Development Company, LLC (IS), entered into a Water and Sewer Capacity and Service Agreement (IS Agreement). Section 1.1.2 of the agreement states that IS will pay Glenwood $96,000 (4,000 gpd at $7.00 per gallon and 8,000 gpd at $8.50 per gallon) for 12,000 gpd.

As stated in the Uniform System of Accounts for Water and Wastewater Utilities, CIAC shall include "any amount or item of money, services or property received by a utility, from any person or governmental agency, any portion of which is provided at no cost to the utility, which represents an addition or transfer to the capital of the utility, and which is utilized to offset the acquisition, improvement or construction costs of the utility's property, facilities, or equipment used to provide utility services to the public." The cost of a sewer treatment plant is a utility asset, and any monies received to offset that cost is CIAC. Based on Aqua's March 30, 2007, late filed exhibit, 12,000 gpd of treatment plant capacity was sold to another developer, IS, for $96,000. This $96,000 received from IS is CIAC, and the net plant in service being acquired by Aqua should be updated to reflect this additional CIAC, regardless of whether it was paid directly to NCWSC or indirectly through NCWSC's affiliated company, Glenwood. This treatment of payments for reservation of capacity is consistent with the Commission's treatment of reservation of capacity fees in Docket No. W-354, Sub 266, a general rate case application by Carolina Water Service, Inc. of North Carolina. In that case, the Commission concluded that the reservation of capacity fees should be included in CIAC upon receipt.

With the sale of the 12,000 gpd, the capacity reserved by NCWSC/Glenwood under the Purchase Agreement was reduced to 8,000 gpd. On July 23, 2007, Aqua, NCWSC and Glenwood entered into a second amendment to the Purchase Agreement, under which NCWSC/Glenwood relinquished its claim to this remaining 8,000 gpd. Since the 8,000 gpd of capacity is no longer reserved by NCWSC/Glenwood, it is appropriate to include the cost of this capacity in the net plant in service being acquired, since Aqua will control this capacity, and NCWSC/Glenwood will no longer be able to sell this capacity to other developers.

Summary

Based upon the foregoing, the Hearing Examiner concludes that the net plant in service to be acquired by Aqua is $87,296, consisting of the following:

Item	Water	Sewer	Total
Plant in service acquired	$ 39,120	$ 337,045	$ 376,165
Accumulated depreciation acquired	(38,593)	(119,279)	(157,872)
CIAC acquired	0	(146,000)	(146,000)
Accumulated amort. of CIAC acquired	0	15,003	15,003
Net plant in service acquired	$ 527	$ 86,769	$ 87,296

Since the amended purchase price of $87,296 is equal to the net book value of the assets being acquired, there is no acquisition adjustment to be addressed in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18 - 21

The evidence supporting these findings of fact is contained in the application and in the testimony of Public Staff witness Furr and Company witness Phillips. These findings are not contested.

IT IS, THEREFORE ORDERED as follows:

1. That $20,000 of the $490,000 unassigned bond surety for Aqua shall be assigned to Cole Plaza Shopping Center, Chatham Crossing Shopping Center, and Cole Place Development Subdivision. The remaining unassigned bond surety shall be $470,000.

2. That the transfer of the water and sewer utility franchise serving Cole Park Plaza Shopping Center, Chatham Crossing Shopping Center, and Cole Place Development Subdivision in Chatham County, North Carolina, from North Chatham Water and Sewer Company, LLC, to Aqua North Carolina, Inc., is hereby approved.

3. That Appendix A shall constitute Aqua's Certificate of Public Convenience and Necessity.

4. That the Schedule of Rates, attached hereto as Appendix B, is hereby approved and is deemed to be filed with the Commission pursuant to G.S. 62-138. The approved rates for providing water and sewer utility service are hereby authorized to become effective for service rendered on and after the effective date of this Order.

5. That the Notice to Customers, attached hereto as Appendix C, shall be mailed with sufficient postage or hand delivered to all customers no later than 20 days after the effective date of this Order; and that Aqua shall file the attached Certificate of Service, properly signed and notarized, no later than 30 days after the effective date of this Order.

6. That Aqua shall provide written notification to the Commission within 10 days after the transfer has been completed.

7. That the franchises granted to NCWSC in Docket No. W-1101, Subs 0 and 1, are hereby cancelled upon receipt of the written notification that the transfer has been completed.

8. That this Order shall not be treated or cited as precedent in any future proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This is the 20th day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

rb081007.01

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. W-218, SUB 245

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

AQUA NORTH CAROLINA, INC.
is granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

to provide water and sewer utility service

in

COLE PARK PLAZA SHOPPING CENTER
CHATHAM CROSSING SHOPPING CENTER
COLE PLACE DEVELOPMENT SUBDIVISION

Chatham County, North Carolina

subject to any orders, rules, regulations,
and conditions now or hereafter lawfully made
by the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

APPENDIX B
PAGE 1 OF 2

SCHEDULE OF RATES

for

AQUA OF NORTH CAROLINA, INC.

for providing water and sewer utility service in

COLE PARK PLAZA SHOPPING CENTER, CHATHAM CROSSING SHOPPING CENTER, AND COLE PLACE DEVELOPMENT SUBDIVISION
Chatham County, North Carolina

Monthly Water Utility Service Rates:

Base charge, zero usage	
¾" meter	$ 12.75
1" meter	$ 35.00
1 ½" meter	$ 75.00
2" meter	$100.00
3" meter	$135.00
4" meter	$225.00
Usage charge, per 1,000 gallons	
0 - 5,000 gallons	$ 7.00
5,000 – 8,000 gallons	$ 8.50
over 8,000 gallons	$ 10.00

Monthly Sewer Utility Rates:

Residential Users:	
Flat Rate	$ 26.00
Non-Residential Users:	
¾" meter	$ 30.09
1"meter	$ 82.60
1 ½" meter	$177.00
2" meter	$236.00
3" meter	$318.60
4" meter	$531.00
Usage charge, per 1,000 gallons	$ 4.484

New Account Charge: $ 15.00

APPENDIX B
PAGE 2 OF 2

Charge for New Connections:

Customer inside franchised service area	Actual Cost
Customer outside franchised service area	Actual Cost

Reconnection Charges:

If water or sewer service cut off by utility for good cause	$ 30.00
If water or sewer service discontinued at customer's request	$ 5.00
If sewer service is cut off by utility by discontinuing water	None
If sewer service is cut off for any other reasons than above	Actual Cost

Returned Check Charge:	$ 20.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charge for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-218, Sub 245, on this the 20th day of August 2007.

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX C
PAGE 1 OF 2

NOTICE TO CUSTOMERS
DOCKET NO. W-218, SUB 245
DOCKET NO. W-1101, SUB 3
BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Aqua North Carolina, Inc., to acquire the water and sewer utility systems of North Chatham Water & Sewer Company, LLC, to charge increased rates for water utility service, and restructured rates for sewer utility service to its customers in Cole Park Plaza Shopping Center, Chatham Crossing Shopping Center, and Cole Place Development Subdivision in Chatham County, North Carolina. The new approved rates are as follows:

WATER AND SEWER – SALE/TRANSFER

Monthly Water Utility Service Rates:

Base charge, zero usage	
¾" meter	$ 12.75
1" meter	$ 35.00
1 ½" meter	$ 75.00
2" meter	$100.00
3" meter	$135.00
4" meter	$225.00
Usage charge, per 1,000 gallons	
0 - 5,000 gallons	$ 7.00
5,000 – 8,000 gallons	$ 8.50
over 8,000 gallons	$ 10.00

APPENDIX C
PAGE 2 OF 2

Monthly Sewer Utility Rates:

Residential Users:	
Flat Rate	$ 26.00
Non-Residential Users:	
¾" meter	$ 30.09
1" meter	$ 82.60
1 ½" meter	$177.00
2" meter	$236.00
3" meter	$318.60
4" meter	$531.00
Usage charge, per 1,000 gallons	$ 4.484

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August 2007.

NORTH CAROLINA UTILITIES COMMISSION
Patricia Swenson, Deputy Clerk

WATER AND SEWER – SALE/TRANSFER

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-218, Sub 245, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ____________________, 2007.

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-218, Sub 245.

Witness my hand and notarial seal, this the ____ day of _______________, 2007.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ____________________________________

Date

DOCKET NO. WR-174, SUB 3
DOCKET NO. WR-309, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. WR-174, SUB 3 In the Matter of Violations of Statutes and Commission Rules by Strickland Farms General Partnership and DOCKET NO. WR-309, SUB 2 In the Matter of Violations of Statutes and Commission Rules by J P Realty IV, LLC	)))))))))))))	RECOMMENDED ORDER ACCEPTING STIPULATIONS

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, October 11, 2006, at 10:00 a.m.

BEFORE: Corrie V. Foster, Hearing Examiner

APPEARANCES:

For Strickland Farms General Partnership and J P Realty IV, LLC:

Ralph McDonald[1]
Bailey & Dixon, L.L.P.
Post Office Box 1351
Raleigh, North Carolina 27602

For the Using and Consuming Public:

Robert S. Gillam, Staff Attorney
Tab C. Hunter, Staff Attorney
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4326

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[1] Strickland Farms General Partnership and J P Realty IV, LLC had no counsel of record at the October 11, 2006 hearing but employed Mr. McDonald as their counsel subsequently.

RESALE OF WATER/SEWER – SHOW CAUSE

FOSTER, HEARING EXAMINER: On July 12, 2006, the Public Staff of North Carolina Utilities Commission (Public Staff) filed a Petition for Order to Show Cause against Strickland Farms General Partnership and J P Realty IV, LLC (Collectively Respondents), alleging that Respondents had violated G.S. 62-110(a), G.S. 62-110(g), G.S. 62-139(a), and Commission Rules R18-5(a), R18-6(a), R18-7(a) and R18-7(f), and requested that Respondents be penalized under G.S. 62-310(a) and required to make certain refunds to their customers.

On August 3, 2006, the Commission issued an Order Scheduling Show Cause for Hearing, directing Respondents to appear at a hearing on September 7, 2006 and show cause why the relief sought by the Public Staff should not be granted. In response to a series of motions for extension of time by the Public Staff and Respondents, the Commission rescheduled the hearing for October 11, 2006.

On September 23, 2006, the Public Staff filed the testimony and exhibits of Katherine A. Fernald, Supervisor of the Water Section of the Public Staff Accounting Division. Ms. Fernald's testimony did not restate all the allegations of the Public Staff's initial petition, but she did testify that Respondent - Strickland Farms General Partnership (Strickland Farms) had violated G. S. 62-110(g) and 62-139 by charging rates for resold water and sewer utility service different from the rates approved by the Commission, and that Strickland Farms had violated Commission Rule R18-7(f) by failing to post in public view in its business office the materials required to be posted by the rule. She recommended that Strickland Farms be required to pay penalties under G.S. 62-310(a) in the amount of $96,702. Ms. Fernald also testified that Respondent - J P Realty has violated G.S. 62-110 (g) and 62-139 by charging rates for resold water and sewer utility service different from the rates approved by the Commission, and that J P Realty had violated G.S. 62-110(a) and (g) by reselling water and sewer service without a certificate of authority prior to the issuance of its certificate in December 2004. She recommended that J P Realty be required to pay penalties under G.S. 62-310(a) in the amount of $42,349.

At the hearing on October 11, 2006, John Politis, the president and general partner of Strickland Farms and president of J P Realty, appeared without counsel and moved that the hearing be rescheduled in order to allow him additional time to employ counsel. The Hearing Examiner denied the motion.. The Public Staff presented the testimony and exhibits of Ms. Fernald. Mr. Politis testified very briefly for Respondents. After testimony was received, the Hearing Examiner authorized Respondents to employ counsel and submit written testimony on or before November 28, 2006. The deadline for the filing of Respondents' written testimony was subsequently extended to January 16, 2007.

On January 11, 2007, the parties notified the Commission that they were engaged in settlement negotiations and wished to be relieved of any further obligation to file testimony and to be authorized to file a settlement agreement and joint proposed order on January 31, 2007. In an order issued on January 19, 2007, the Commission granted the parties' request.

In a motion filed on January 30, 2007, the parties indicated that their settlement negotiations were continuing and requested that the deadline for filing a settlement agreement and joint proposed order be extended until February 14, 2007.

On January 31, 2007, the Commission issued an order extending the deadline to file settlement agreement and proposed order until February 16, 2007. Subsequently the parties requested a further extension of time, which was granted by order of February 15, 2007.

On February 28, 2007, the Commission issued its last order granting further extension for the parties to file their documents.

On March 9, 2007, the Public Staff and Respondents filed a joint stipulation settling the issues in this proceeding, together with a joint proposed order and a confession of judgment. Enclosed with the filings, were checks in the amount of $1,730.90 on the account of J P Realty, and $6,462.00 on the account of Strickland Farms, both payable to the Commission, representing the first payments to be made to the Commission from the Respondents under the terms of their joint stipulation and proposed recommended order. They requested that the Commission's order in this matter be issued and made final immediately.

Based on the foregoing, the evidence and exhibits presented at the hearing the parties' joint stipulation, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT

1. In its Order Granting Temporary Operating Authority and Approval of Rates, issued on February 26, 2003, in Docket No. WR-174, Sub 0, the Commission granted Strickland Farms temporary operating authority to provide water and sewer utility service in Strickland Farms Apartments in Wake County, North Carolina, pursuant to G.S. 62-110(g). On August 1, 2004, pursuant to section 9 of North Carolina Session Law 2004-143, Strickland Farms' temporary operating authority was converted to a certificate of authority to charge for water or sewer service. Accordingly, Strickland Farms is properly before the Commission pursuant to the Public Staff's Petition for Order to Show Cause and the Commission's Order Scheduling Show Cause for Hearing.

2. In its Order Granting Certificate of Authority and Approving Rates, issued on December 22, 2004, in Docket No. WR-309, Sub 0, the Commission granted J P Realty a certificate of authority to charge for water and sewer utility service in Lenoxplace Apartments in Wake County, North Carolina, pursuant to G.S. 62-110(g). Accordingly, J P Realty is properly before the Commission pursuant to the Public Staff's Petition for Order to Show Cause and the Commission's Order Scheduling Show Cause for Hearing.

3. The Public Staff has asserted in its pleadings and testimony in Docket No. WR-309, SUB 2, and continues to assert, that J P Realty has violated G.S. 62-110(a) and (g) and 62-139, and should be penalized in the amount of $42,349 under G.S. 62-310(a).

4. The Public Staff has asserted in its pleadings and testimony in Docket No. WR-174, SUB 3, and continues to assert, that Strickland Farms has violated G.S. 62-110(g) and 62-139, as well as Commission Rule R18-7(f), and should be penalized in the amount of $96,702 under G.S. 62-310(a).

5. Respondents in both dockets deny that they have committed any violation of statutes or Commission rules.

6. The Commission makes no finding as to whether Respondents have in fact violated any statutes or Commission rules. However, the parties have stipulated that J P Realty shall pay the sum of $12,116 in settlement of this proceeding; that the payment shall be made in an initial installment of $1,730.90, due on or before February 20, 2007, and six subsequent monthly payments of $1,730.85, due on or before the 20th day of each month from March through August, 2007; and that J P Realty shall bear the full and sole responsibility for ensuring that each payment is actually received in the office of the Chief Clerk of the Commission, in cash or by cashier's check, before the close of business on the applicable deadline day. The parties have further stipulated that if J P Realty defaults in making any monthly payment, the entire remaining balance shall immediately become due and payable, without the need for any notice of default or other notice by the Public Staff, the Commission, or any other entity.

7. The Commission makes no finding as to whether Strickland Farms has in fact violated any statutes or Commission rules. However, the parties have stipulated that Strickland Farms shall pay the sum of $45,234 in settlement of this proceeding; that the payment shall be made in seven monthly installments of $6,462, due on or before the 20th day of each month from February through August, 2007; and that Strickland Farms shall bear the full and sole responsibility for ensuring that each payment is actually received in the office of the Chief Clerk of the Commission, in cash or by cashier's check, before the close of business on the applicable deadline day. The parties have further stipulated that if Strickland Farms defaults in making any monthly payment, the entire remaining balance shall immediately become due and payable, without the need for any notice of default or other notice by the Public Staff, the Commission, or any other entity.

8. Prior to or concurrently with the issuance of the Commission's order in these dockets, J P Realty and Strickland Farms are signing a Confession of Judgment in favor of the Commission in the amount of $12,116 and $45,234, respectively. The parties have stipulated that Respondents designate the Public Staff as their agent for purposes of filing the Confession of Judgment in the office of the Clerk of Superior Court of Wake County, and that the Confession of Judgment is not to be filed so long as Respondents are current in making the payments required by the Commission's order, but may be filed immediately upon Respondents' default, without the need for any notice of default or other notice by the Public Staff, the Commission, or any other entity.

CONCLUSIONS

Based upon the foregoing, the Hearing Examiner is of the opinion that the case should be resolved in accordance with the parties' joint stipulation, and that J P Realty shall pay the sum of $12,116 and Strickland Farms shall pay the sum of $45,234 to the Commission, on the terms set forth in the joint stipulation.

IT IS, THEREFORE, ORDERED as follows:

1. That J P Realty shall pay the sum of $12,116 to the Commission in seven monthly installments, with the first installment of $1,730.90 to be paid on or before the 20th day of February, 2007, and the remaining six installments, each in the amount of $1,730.85, to be paid on or before the 20th day of each month from March through August, 2007.

2. That J P Realty shall bear the full and sole responsibility for ensuring that each payment is actually received in the office of the Chief Clerk of the Commission, in cash or by cashier's check, before the close of business on the applicable deadline day.

3. That if J P Realty defaults in making any monthly payment, the entire remaining balance shall immediately become due and payable, without the need for any notice of default or other notice by the Public Staff, the Commission, or any other entity.

4. That Strickland Farms shall pay the sum of $45,234 to the Commission, in seven equal monthly installments of $6,462, with the installments to be paid on or before the 20th day of each month from February through August, 2007.

5. That Strickland Farms shall bear the full and sole responsibility for ensuring that each payment is actually received in the office of the Chief Clerk of the Commission, in cash or by cashier's check, before the close of business on the applicable deadline day.

6. That if Strickland Farms defaults in making any monthly payment, the entire remaining balance shall immediately become due and payable, without the need for any notice of default or other notice by the Public Staff, the Commission, or any other entity.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of March, 2007.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

Cf032007.01

ORDERS AND DECISIONS – PRINTED

INDEX OF ORDERS PRINTED

ORDERS AND DECISIONS – PRINTED

INDEX OF ORDERS AND DECISIONS LISTED

GENERAL ORDERS

ORDERS AND DECISIONS LISTED

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ELECTRIC – Miscellaneous

Dominion North Carolina Power; Virginia Electric & Power Co., d/b/a -- E-22, SUB 439; Order Allowing Withdrawal of Petition and Closing Docket (02/19/2007)

Duke Energy Carolinas, LLC - E-7, SUB 819; Order Issuing Declaratory Ruling (03/20/2007)

Progress Energy Carolinas, Inc.; Carolina Power & Light Company, d/b/a --E-2,

SUB 906; Order Allowing Petition to be Withdrawn and Closing Docket (08/31/2007)

SUB 910; Order Allowing Request to Provide Native Load Firm Service to Towns (11/20/2007)

ELECTRIC - Rate Schedules/Riders/Service Rules and Regulations

Duke Energy Carolinas, LLC -- E-7,

SUB 666; Order Approving Request (05/22/2007)

SUB 784; Order Approving Request (05/22/2007)

SUB 833; Order Approving Purchased Power Cost Rider (08/30/2007)

SUB 835; Order Approving Lighting Schedule Revisions (08/30/2007)

SUB 837; Order Approving Rider US (10/25/2007)

Progress Energy Carolinas, Inc.; Carolina Power & Light Company, d/b/a — E-2,

SUB 904; Order Approving Area and Street Lighting Rate Revisions (07/12/2007)

SUB 908; Order Approving Compact Fluorescent Light Bulb Pilot Program (09/19/2007)

ELECTRIC – Securities

Duke Energy Carolinas, LLC -- E-7, SUB 836; Order Granting Authority to Issue and Sell Securities (09/12/2007)

ORDERS AND DECISIONS LISTED

ELECTRIC - Sale/Transfer

Progress Energy Carolinas, Inc.; Carolina Power & Light Company, d/b/a -- E-2, SUB 884; Order Approving Conveyance (03/08/2007)

ELECTRIC SUPPLIER

ELECTRIC SUPPLIER - Reassignment of Service Area/Exchange

Electric Supplier - ES-117, SUB 0; Order Approv. Agreement of Electric Suppliers (03/30/2007)
Electric Supplier - ES-118, SUB 0; Order Approv. Agreement of Electric Suppliers (03/15/2007)
Electric Supplier - ES-119, SUB 0; Order Approv. Agreement of Electric Suppliers (03/30/2007)
Electric Supplier - ES-120, SUB 0; Order Approv. Agreement of Electric Suppliers (03/30/2007)
Electric Supplier - ES-121, SUB 0; Order Approv. Agreement of Electric Suppliers (04/19/2007)
Electric Supplier - ES-122, SUB 0; Order Approving Territorial Agreement (04/19/2007)
Electric Supplier - ES-123, SUB 0; Order Assigning Service Territory (04/19/2007)
Electric Supplier - ES-124, SUB 0; Order Approving Agreement (11/08/2007)
Electric Supplier - ES-126, SUB 0; Order Approving Agreement of Suppliers (07/06/2007)
Electric Supplier - ES-127, SUB 0; Order Approving Agreement (07/12/2007)
Electric Supplier - ES-136, SUB 0; Order Approving Agreement (07/12/2007)
Electric Supplier - ES-140, SUB 0; Order Approv. Agreement of Electric Suppliers (11/08/2007)
Electric Supplier - ES-141, SUB 0; Order Approv. Agreement of Electric Suppliers (11/08/2007)
Electric Supplier - ES-142, SUB 0; Order Approv. Agreement of Electric Supplier (11/21/2007)

NATURAL GAS

NATURAL GAS – Accounting

Piedmont Natural Gas Co. -- G-9, SUB 545; Order Approving. Deferral Accounting (10/03/2007)

NATURAL GAS - Adjustments of Rates/Charges

Cardinal Extension Company, LLC -- G-39, SUB 11; Order Approving Adjustment to Fuel Retention Percentage (03/15/2007)

North Carolina Natural Gas Corp. -- G-21, SUB 465; Order Closing Docket (08/16/2007)

Piedmont Natural Gas Company, Inc. -- G-9,

SUB 507; Order Closing Docket (08/08/2007)

SUB 521 & SUB 548; Order Approving Rate Adjustments Effective November 1, 2007 (10/31/2007)

SUB 528; Order Approving Rate Decrements (08/29/2007)

SUB 536; Order Allowing Rate Changes Effective January 1, 2007 (01/05/2007)

Public Service Co. of NC -- G-5, SUB 486; Order Allowing Rate Changes Effective January 1, 2007 (01/05/2007)

ORDERS AND DECISIONS LISTED

NATURAL GAS - Complaint

Piedmont Natural Gas Co. -- G-9, SUB 534; Order Dismiss. Complaint and Closing Docket (07/05/2007)

Public Service Co. – G-5, SUB 483; Recommended Order on Complaint (Shirley Thurmond) (08/03/2007)

NATURAL GAS - Contracts/Agreements

Frontier Energy, LLC -- G-40, SUB 68; Order Approving Contract (03/29/2007)

NATURAL GAS - Filings Due per Order or Rule

Public Service Company of N.C. Inc. -- G-5, SUB 323; Order Discontinuing Reporting Requirement and Closing Docket (02/09/2007)

NATURAL GAS – Miscellaneous

Piedmont Natural Gas Company -- G-9, SUB 547; Order Approving Disposition (10/25/2007)

Public Service Company of N.C. -- G-5,

SUB 484; Order Accept. Agreement for Filing and Allowing Operation Under the Agreement (01/10/2007)

SUB 485; Order Approving Deferral Accounting (01/05/2007)

SUB 491; Order Allowing Cross-Over of Franchised Territory (07/27/2007)

SUB 492; G-9, SUB 543; Order Allowing Adjust. to Franchise Territories (09/12/2007)

NATURAL GAS - Rate Increase

Piedmont Natural Gas Co. -- G-9, SUB 499; Order Approv. Revising Discount. Rate Financ. of Weatherizat. Products and Install. of Program Details (10/03/2007); Order Approv.Reallocat. of Funds Assoc. with 2007 Conserv. Comm. to Lower Income (11/28/2007)

NATURAL GAS - Rate Schedules/Riders/Service Rules and Regulations

Public Service Company of N.C. -- G-5,

SUB 451; Order Approv. Amend. to Rate Sched. 115-Open Flame Gas Lanterns (07/12/2007)

SUB 490; Order Allowing Rate Changes Effective July 1, 2007 (06/27/2007)

222 South Caldwell Street Ltd. -- G-52, SUB 0; Order Approv. Metering Plan (09/26/2007)

NATURAL GAS - Sale/Transfer

Frontier Energy, LLC -- G-40, SUB 67; Order Approv. Purchase of Stock and Transfer of Control of Company (09/13/2007)

ORDERS AND DECISIONS LISTED

SMALL POWER PRODUCER

SMALL POWER PRODUCER – Certificate

SMALL POWER PRODUCER – *Certificates Issued*

Company	Docket No.	Date Issued
Ambient Advisory Services, Inc.	SP-191, SUB 0	(03/15/2007)
Alexander, Jim & Linda	SP-228, SUB 0	(09/20/2007)
Aquesta Bank	SP-203, SUB 0	(06/14/2007)
Berntsen, Jon	SP-210, SUB 0	(07/06/2007)
Blessington, Mark	SP-237, SUB 0	(11/08/2007)
Bundy, John F.	SP-206, SUB 0	(06/27/2007)
Burton, Rachel	SP-221, SUB 0	(08/22/2007)
Campbell, Charles C.	SP-185, SUB 0	(01/17/2007)
Campbell, Family Investments	SP-207, SUB 0	(06/27/2007)
Carolina Country Builders of Chatham County	SP-234, SUB 0	(11/08/2007)
Cohen; K. Julianne	SP-239, SUB 0	(11/08/2007)
Coiled Spring Arbor, Inc.	SP-244, SUB 0	(12/14/2007)
Cooper, Chuck	SP-202, SUB 0	(06/14/2007)
Curnes, John	SP-199, SUB 0	(05/16/2007)
Dalzel, LLC	SP-227, SUB 0	(10/25/2007)
Davids, Tracy	SP-233, SUB 0	(10/03/2007)
Davis, Michael	SP-238, SUB 0	(11/08/2007)
Delta Products Corporation	SP-213, SUB 0	(10/25/2007)
Dodd, Randy	SP-241, SUB 0	(11/28/2007)
Dozer, Jeff	SP-224, SUB 0	(08/31/2007)
Edgley, Jo Kay & Darrell	SP-192, SUB 0	(03/23/2007)
Gay Cheney	SP-223, SUB 0	(08/31/2007)
Goettler, Claudia	SP-230, SUB 0	(09/20/2007)
Graf, Steve	SP-248, SUB 0	(12/20/2007)
Hydro Matrix Partnership, Ltd.	SP-127, SUB 2	(07/12/2007)
Hauser, Edward Joseph	SP-214, SUB 0	(07/27/2007)
Helms, Mark	SP-187, SUB 0	(02/07/2007)
Keaton, Nancy L.	SP-225, SUB 0	(08/31/2007)
Kieffer, Henri	SP-226, SUB 0	(08/31/2007)
King, Dr. Stephen C.	SP-189, SUB 0	(02/14/2007)
Kirby; Suzanne	SP-236, SUB 0	(11/08/2007)
Leder, John A.	SP-212, SUB 0	(07/12/2007)
McCullough, Melissa	SP-204, SUB 0	(06/14/2007)
Megawatt Solar, Inc.	SP-211, SUB 0	(07/06/2007)
Milton, Roy	SP-196, SUB 0	(04/10/2007)
Myers, Ryan	SP-195, SUB 0	(03/30/2007)
Pacifica Home Owners' Association	SP-232, SUB 0	(10/25/2007)
Personal Touch Interiors	SP-220, SUB 0	(10/25/2007)
Pippin Home Designs, Inc.	SP-235, SUB 0	(11/08/2007)

SMALL POWER PRODUCER – *Certificates Issued (Continued)*

Company	Docket No.	Date Issued
Pope, Nancy	SP-186, SUB 0	(01/17/2007)
Powers, Mark	SP-201, SUB 0	(06/01/2007)
Presnell, Lacy	SP-216, SUB 0	(08/03/2007)
David Rhodes	SP-208, SUB 0	(08/23/2007)
Ringenburg, David	SP-229, SUB 0	(09/20/2007)
Seaman, Russell	SP-188, SUB 0	(02/07/2007)
Seaton, Kathy	SP-217, SUB 0	(08/03/2007)
The Village Woodsworks, Inc.	SP-240, SUB 0	(11/08/2007)
Thorn, Michael	SP-247, SUB 0	(12/20/2007)
Town of Chapel Hill Fire Station	SP-209, SUB 0	(07/06/2007)
Vanca, William	SP-222, SUB 0	(08/23/2007)
Warren Wilson College	SP-215, SUB 0	(08/03/2007)
Wiener, David	SP-205, SUB 0	(06/27/2007)
Zerkle, Andrew J.	SP-200, SUB 0	(05/22/2007)

SMALL POWER PRODUCER - Declaratory Ruling

Gas Recovery Systems, LLC -- SP-197, SUB 0; Order Approving Transfer of Certificate and on Request for Declaratory Ruling (05/16/2007)

SMALL POWER PRODUCER - Electric Generation Certificate

Northwest Wind Developers, LLC -- SP-167, SUB 1; Order Dismissing Application Without Prejudice (07/26/2007)

SMALL POWER PRODUCER - Sale/Transfer

Catawba Valley Habitat for Humanity -- SP-152, SUB 1; SP-190, SUB 0; Order Transferring Certificate (03/08/2007)

Harden Manufacturing Company -- SP-10, SUB 1; SP-194, SUB 0; Order Approving Transfer (03/30/2007)

Henry River Power Company Inc. -- SP-36, SUB 1; SP-162, SUB 1; Order Transferring Certificate (03/09/2007)

Weyerhaeuser Co. -- SP-55, SUB 1; SP-193, SUB 0; Order Transferring Certificate (03/23/2007)

SPECIAL CERTIFICATE/PSP

SPECIAL CERTIFICATE/PSP – Certificate

Brown, Sr.; Duke C. -- SC-1793, SUB 0; Order Issuing Certificate (01/05/2007)
City Tele Coin Company, Inc. -- SC-1796, SUB 0; Order Issuing Certificate (12/13/2007)
Sterling Payphones, LLC -- SC-1795, SUB 0; Order Issuing Certificate (10/24/2007)
The New Telephone Company -- SC-1794, SUB 0; Order Issuing Certificate (07/11/2007)

ORDERS AND DECISIONS LISTED

SPECIAL CERTIFICATE/PSP – *Orders Issued Canceling Certificates*

Company	Docket No.	Date Issued
A & L Fashions; Wallace Cox, d/b/a	SC-904, SUB 2	(05/16/2007)
American Public Payphone Corporation	SC-1553, SUB 2	(08/01/2007)
AT&T Communications	SC-40, SUB 2	(08/01/2007)
Blue Max Trucking, Inc.	SC-1445, SUB 2	(09/10/2007)
Duran; Lupie	SC-789, SUB 1	(03/05/2007)
ETS Payphones, Inc.	SC-1434, SUB 2	(03/15/2007)
Funtime Amusements, Inc.	SC-1773, SUB 1	(01/30/2007)
Hair Cuttery; Creative Hairdressers, Inc.	SC-1061, SUB 3	(04/16/2007)
Hollis Oil Company	SC-467, SUB 1	(08/23/2007)
Higgins, Mark	SC-1746, SUB 1	(12/10/2007)
Nautilus Fitness Center	SC-556, SUB 2	(11/13/2007)
Quik Shop-Gas Stop	SC-251, SUB 1	(08/23/2007)
Rutherford-Spindale High School	SC-416, SUB 1	(08/01/2007)
SmartStop, Inc. -	SC-1459, SUB 4	(01/05/2007)
Southeast Communications, Inc.	SC-1397, SUB 2	(12/10/2007)
Southern Tell Phones	SC-323, SUB 1	(02/19/2007)
Self-Serv, Inc.	SC-1758, SUB 1	(11/13/2007)
Sky Best Communications	SC-1615, SUB 1	(08/01/2007)
Symtelco, LLC	SC-1769, SUB 1	(10/15/2007)
T.E.C. PAY.COM, INC.	SC-1142, SUB 3	(02/19/2007)
TCG Public Communications	SC-1632, SUB 1	(03/15/2007)

Prince, Michael L. -- SC-1000, SUB 13; SC-1754, SUB 1; Order Affirming Previous Commission Order Canceling Certificate (09/24/2007)

Special Certificates – SC-1380, SUB 1; SC-1550, SUB 1; SC-1607, SUB 1; SC-1668, SUB 1; SC-1703, SUB 1; SC-1716, SUB 1; SC-1718, SUB 1; SC-1722, SUB 1; SC-1733, SUB 1; SC-1747, SUB 1; SC-378, SUB 1; SC-932, SUB 2; SC-1000, SUB 12; Order Affirming Previous Commission Order Canceling Certificate (01/05/2007)

SPECIAL CERTIFICATE/PSP – Miscellaneous

Hatteras Sands RV Resort -- SC-1641, SUB 1; Order Reissuing Certificate (10/15/2007)

HQ Payphone Services -- SC-1788,
SUB 1; Order Reissuing Certificate (01/30/2007)
SUB 2; Order Reissuing Certificate (12/13/2007)

HSI Telecom, Inc. - SC-1770, SUB 1; Order Reissuing Certificate (02/19/2007)

Inmate Calling Solutions, LLC -- SC-1727, SUB 1; Order Reissuing Certificate (09/24/2007)

TelSouth Incorporated of N.C. -- SC-1452, SUB 2; Order Reissuing Certificate (12/13/2007)

SPECIAL CERTIFICATE/PSP – Reinstate Certificate

Special Certificates – SC-932, SUB 2; SC-1380, SUB 1; SC-1550, SUB 1; SC-1607, SUB 1; SC-1000, SUB 12; Errata Order Reinstating Certain Certificates (01/12/2007)

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TELECOMMUNICATIONS

TELECOMMUNICATIONS – Certificate

Local Certificates – *Orders Issued*

Company	Docket No.	Date
Bandwidth.com CLEC, LLC	P-1432, SUB 0	(05/16/2007)
Buggs Island Telephone Co.	P-1438, SUB 1	(07/11/2007)
Custom Teleconnect, Inc.	P-1085, SUB 1	(12/31/2007)
Hotwire Communications, LTD	P-1442, SUB 0	(12/10/2007)
Inter-Tel NetSolutions, Inc.	P-900, SUB 2	(09/10/2007)
Infotelecom, LLC	P-1375, SUB 1	(03/26/2007)
Network Innovations, Inc.	P-1427, SUB 0	(06/15/2007)
Neutral Tandem-North Carolina, LLC	P-1429, SUB 0	(03/26/2007)
One Voice Communications, Inc.	P-1174, SUB 1	(06/01/2007)
Sage Telecom, Inc.	P-1440, SUB 0	(11/19/2007)
StarVox Communications, Inc.	P-1379, SUB 1	(11/13/2007)
Touchtone Communications, Inc.	P-1224, SUB 1	(11/13/2007)
Vantage Telecom, d/b/a Newroads Telecom	P-1425, SUB 0	(01/23/2007)
Wholesale Carrier Services, Inc.	P-1168, SUB 1	(11/19/2007)
WinSonic Digital Media Group, Ltd.	P-1430, SUB 1	(03/15/2007)
Yipes Enterprise Services, Inc.	P-1441, SUB 0	(11/26/2007)

Long Distance Certificates – *Orders Issued*

Company	Docket No.	Date
Access2go, Inc.	P-1443, SUB 0	(10/24/2007)
America Net, LLC	P-1437, SUB 0	(04/24/2007)
Applewood Communications Corp.	P-1436, SUB 0	(07/11/2007)
Brydels Communications, d/b/a AMIGOS	P-1434, SUB 1	(03/26/2007)
Buggs Island Telephone Co.	P-1438, SUB 0	(06/01/2007)
Cheap2Dial Telephone, LLC	P-1435, SUB 0	(04/16/2007)
Cordia Communications Corp.	P-1431, SUB 0	(03/05/2007)
Cost Plus Communications, LLC	P-1444, SUB 0	(11/19/2007)
Hotwire Communications, Ltd.	P-1442, SUB 1	(11/26/2007)
Neutral Tandem-North Carolina, LLC	P-1429, SUB 1	(02/19/2007)
Pulse Telecom, LLC	P-1428, SUB 0	(01/30/2007)
Sage Telecom, Inc.	P-1440, SUB 1	(10/15/2007)
STi Prepaid, LLC	P-1433, SUB 0	(03/15/2007)
Telcentrex, LLC	P-1426, SUB 0	(01/23/2007)
Twin City Capital, d/b/a Small Business America, Inc.	P-1231, SUB 2	(07/11/2007)
UnityComm, LLC	P-1446, SUB 0	(12/10/2007)
WinSonic Digital Media Group, Ltd.	P-1430, SUB 0	(03/15/2007)

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TELECOMMUNICATIONS – Certificate *(Continued)*

Inter-Tel NetSolutions, Inc. -- P-900, SUB 1; Order Denying Application without Prejudice and Closing Docket (01/05/2007)

Sprint Communications Co. L.P. -- P-294, SUB 7; Order Amending Certificate (03/21/2007)

TELECOMMUNICATIONS – Cancellation of Certificate

Local & Long Distance Certificates Canceled—*Orders Issued*

Company	Docket No.	Date
AC License Holding Corporation, d/b/a	P-1313, SUB 1	(05/25/2007)
Acceris Management and Acquisition LLC	P-1369, SUB 1	(09/21/2007)
Alltel Communications, Inc.	P-514, SUB 27	(06/12/2007)
ASC Telecom, Inc.	P-806, SUB 2	(05/25/2007)
Business Options, Inc.	P-529, SUB 2	(01/30/2007)
Buzz Telecom Corporation	P-1221, SUB 1	(01/30/2007)
Cognigen Networks, Inc.	P-1254, SUB 1	(12/13/2007)
Globalphone Corporation	P-1344, SUB 1	(02/19/2007)
Infone, LLC	P-1190, SUB 1	(03/26/2007)
Infonet Telecommunications Corp.	P-1157, SUB 1	(08/23/2007)
Line 1 Communications, LLC	P-1180, SUB 1	(01/30/2007)
MGEN Services Corp.	P-1249, SUB 1	(10/15/2007)
Nautilus Telecommunications, Inc.	P-1331, SUB 1	(08/23/2007)
New Access Communications LLC	P-1277, SUB 1	(09/21/2007)
OnFiber Carrier Services, Inc.	P-977, SUB 3	(10/15/2007)
SmartStop, Inc.	P-728, SUB 1	(03/26/2007)
TransAmerica Telecom, Inc.	P-1414, SUB 1	(12/10/2007)
Yestel, Inc.	P-1398, SUB 1	(05/25/2007)

Blonder Tongue Telephone, LLC -- P-1320, SUB 2; Order Canceling Certificates and Closing Docket (01/05/2007)

Gates Communications, Inc. -- P-1086, SUB 1; Order Canceling Certificate and Closing Docket (01/04/2007)

NTC Communications, LLC -- P-1351, SUB 2; Order Canceling Certificates (03/08/2007)

OnFiber Carrier Services, Inc. -- P-977, SUB 3 Errata Order (10/24/2007)

Pac-West Telecomm, Inc. -- P-1002, SUB 4; Order Authorizing Termination of Service (08/10/2007)

Qwest Interprise America, Inc. -- P-572, SUB 4; Order Canceling Certificates (01/12/2007)

Xspedius Management Co. Switched Services, LLC -- P-1202, SUB 8; Order Canceling Certificates (08/03/2007)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS – Contracts/Agreements

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) – *Orders Issued*

Barnardsville Telephone Company – P-75,
SUB 64 (SunCom Wireless Operating Co.) (03/30/2007)
SUB 65 (New Cingular Wireless PCS) (03/30/2007)
SUB 66 (ALLTEL Communications, Inc.) (03/30/2007)
SUB 67 (Sprint Spectrum, LP) (03/30/2007)
SUB 69; P-76, SUB 59 (Saluda Mountain & Charter Fiberlink NC-CCO) (12/27/2007)

BellSouth Telecommunications, Inc. – P-55,
SUB 1305 (NewSouth Communications Corp.) (03/26/2007)
SUB 1324 (Cbeyond Communications) (12/27/2007)
SUB 1437 (XO Communications Services, Inc.) (12/27/2007)
SUB 1452 (Business Telecom, Inc.) (03/26/2007)
SUB 1466 (Excel Telecommunications, Inc.) (03/26/2007); (07/27/2007)
SUB 1470 (VarTec, Inc.) (03/26/2007); (07/27/2007)
SUB 1502 (Springboard Telecom, LLC) (03/26/2007)
SUB 1506 (DukeNet Communications, LLC) (03/26/2007)
SUB 1521 (Level 3 Communications, LLC) (03/26/2007)
SUB 1567 (KMC Data, LLC) (03/26/2007)
SUB 1574 (Covista, Inc.) (08/31/2007)
SUB 1582 (Connect Communications, LLC) (03/26/2007)
SUB 1583 (VOLO Communications, Inc.) (07/27/2007)
SUB 1588 (BellSouth Long Distance, Inc.) (06/11/2007)
SUB 1590 (New Cingular Wireless PCS, LLC) (08/31/2007)
SUB 1637 (Dialog Telecommunications, Inc.) (03/26/2007)
SUB 1653 (US LEC of North Carolina, Inc.) (03/26/2007)
SUB 1654 (Time Warner Telecom of North Carolina, LP) (05/10/2007)
SUB 1660 (Southern Digital Network, d/b/a FDN Communications) (05/10/2007)
SUB 1662 (CTC Exchange Services) (06/11/2007)
SUB 1673 (Juice Marketing, Inc.) (05/10/2007)
SUB 1676 (New Edge Network, Inc.) (03/08/2007)
SUB 1677 (Trans National Communications International, Inc.) (03/08/2007)
SUB 1678 (Metrostat Communications, Inc.) (03/26/2007)
SUB 1680 (Network PTS, Inc.) (03/26/2007)
SUB 1682 (Ernest Communications, Inc.) (05/10/2007)
SUB 1683 (Communication Specialists Co. of Wilmington, LLC) (05/10/2007)
SUB 1684 (Midwestern Telecommunications, Inc.) (05/10/2007)
SUB 1686 (Springboard Telecom, LLC) (05/10/2007)
SUB 1689 (Airespring, Inc.) ((06/11/2007)
SUB 1690 (Ready Telecom, Inc.) (06/11/2007)
SUB 1691 (ALEC, Inc.) (06/11/2007)
SUB 1692 (American Fiber Network, Inc.) (06/11/2007)

ORDERS AND DECISIONS LISTED

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) – *Orders Issued (Continued)*

BellSouth Telecommunications, Inc. – P-55, *(Continued)*
SUB 1694 (DukeNet Communications, LLC) (06/11/2007); (07/27/2007)
SUB 1701 (Managed Services, Inc.) (07/27/2007)
SUB 1702 (dPi Teleconnect, LLC) (07/27/2007)
SUB 1704 (Windstream Communications, Inc.) (07/27/2007)
SUB 1706 (South Carolina Net, Inc., d/b/a Sprint Telecom) (07/27/2007)
SUB 1707 (3 Voice Communications, Inc.) (08/31/2007)
SUB 1708 (JCM Networking, Inc.) (08/31/2007)
SUB 1709 (Talk America, Inc.) (08/31/2007)
SUB 1713 (Kentucky Data Link, Inc.) (08/31/2007)
SUB 1721 (Covad Communications Company) (12/27/2007)
SUB 1722 (PowerNet Global Communications) (12/27/2007)
SUB 1723 (Juice Marketing, Inc.) (12/27/2007)
Carolina Telephone and Telegraph Co. & Central Telephone Company-- P-7,
SUB 1153; P-10, SUB 780 (Windstream Communications) (03/26/2007)
SUB 1155; P-10, SUB 781 (1-800-RECONEX, Inc.) (05/10/2007)
SUB 1159 P-10, SUB 785 (NuVox Communications, Inc.) (05/10/2007)
SUB 1161; P-10, SUB 787 (SCANA Communications, Inc.) (06/22/2007)
SUB 1162; P-10, SUB 788 (Dialtone & More, Inc.) (06/22/2007)
SUB 1163; P-10, SUB 789 (Managed Services, Inc.) (06/22/2007)
SUB 1164; P-10, SUB 790 (Angles Communication Solutions) (07/27/2007)
SUB 1165; P-10, SUB 791 (MCImetro Access) (07/27/2007); (10/31/2007)
SUB 1167; P-10, SUB 792 (FLATEL, Inc.) (08/31/2007)
SUB 1168; P-10, SUB 793 (Vista PCS, LLC) (10/31/2007)
SUB 1170; P-10, SUB 794 (Time Warner Telecom of North Carolina) (10/31/2007)
SUB 1171; P-10, SUB 795 (Buggs Island Telephone Company) (10/31/2007)
SUB 1172; P-10, SUB 796 (BullsEye Telecom, Inc.) (10/31/2007)
SUB 1173; P-10, SUB 797 (Universal Telecom, Inc.) (10/31/2007)
SUB 1175; P-10, SUB 798 (dPi Teleconnect, LLC) (12/27/2007)
Citizens Telephone Company -- P-12, SUB 108 (Charter Fiberlink NC-CCO) (10/31/2007)
DeltaCom, Inc. – P-500, SUB 18; P-500, SUB 18a (BellSouth Telecomm.) (07/27/2007)
Ellerbe Telephone Company -- P-21,
SUB 72 (Sprint PCS) (03/01/2007)
SUB 73 (SunCom Wireless Operating Company, LLC) (03/30/2007)
MebTel Communications -- P-35,
SUB 109 (Sprint PCS) (03/01/2007)
SUB 110 (Cellco Partnership & Verizon Wireless Personal Comm.) (03/26/2007)
SUB 111 (SunCom Wireless Operating Company) (03/30/2007)
SUB 112 (Sprint Communications) (06/22/2007)
SUB 113 (Level 3 Communications) (08/31/2007)
North State Telephone Company -- P-42,
SUB 149 (MCImetro Access Transmission Services) (05/10/2007)
SUB 155 (United States Cellular Corporation) (03/08/2007)

ORDERS AND DECISIONS LISTED

ORDER APPROVING AGREEMENT(s) and/or AMENDMENT(s) – *Orders Issued (Continued)*

NuVox Communications, Inc. -- P-913; SUB 5 (NuVox Communications, Inc.) (03/08/2007); (06/11/2007)

Pineville Telephone Company -- P-120,
SUB 20 (New Cingular Wireless PCS) (03/01/2007)
SUB 21 (SprintCom) (03/01/2007)
SUB 22 (Alltel Communications, Inc.) (03/01/2007)
SUB 23 (SunCom Wireless Operating Company) (03/01/2007)

Randolph Telephone Company -- P-61,
SUB 96 (Sprint PCS) (03/26/2007)
SUB 97 (SunCom Wireless Operating Company) (03/30/2007)

Saluda Mountain Telephone Company -- P-76,
SUB 54 (Sprint Spectrum, LP) (03/30/2007)
SUB 55 (New Cingular Wireless PCS) (03/30/2007)
SUB 56 (SunCom Wireless Operating Company) (03/30/2007)
SUB 57 (ALLTEL Communications) (03/30/2007)

Service Telephone Company -- P-60,
SUB 74 (SunCom Wireless Operating Company) (03/30/2007)
SUB 75 (New Cingular Wireless PCS) (03/30/2007)
SUB 76 (Sprint Spectrum, LP) (03/30/2007)
SUB 77 (ALLTEL Communications, Inc.) (03/30/2007)

Verizon South, Inc. -- P-19,
SUB 381 (Time Warner Telecom of North Carolina, L.P.) (10/31/2007)
SUB 436 (SBC Telecom, Inc.) (06/11/2007)
SUB 446 (Sprint Communications Company) (06/11/2007)
SUB 449 (Access Point, Inc.) (06/22/2007)
SUB 514 (Airespring, Inc.) (06/22/2007)
SUB 515 (LTS of Rocky Mount, LLC) (06/22/2007)
SUB 516 (Managed Services, Inc.) (06/22/2007)
SUB 518 (ALEC, Inc.) (10/31/2007)

Windstream North Carolina, LLC. -- P-118,
SUB 132 (Sprint Communications Company) (06/22/2007)
SUB 141 (MCImetro Access Transmission Services) (07/27/2007)
SUB 157 (American Fiber Network, Inc.) (06/22/2007)

Xspedius Communications, Inc. – P-1202,
SUB 4 (BellSouth Telecommunications) (07/27/2007)

Charter Fiberlink NC - CCO, LLC -- P-1299, SUB 2 & SUB 3; Order Dismissing Approval Requests and Closing Dockets (09/25/2007)

North State Telephone Company -- P-42, SUB 149; Errata Order (07/09/2007)

Randolph Telephone Company -- P-61, SUB 96; Errata Order (04/02/2007)

Sprint Communications Company L.P. -- P-294, SUB 31; Order Approving Amendment, Dismissing Arbitration and Closing Docket (12/10/2007)

Windstream N. Carolina - P-118, SUB 154; P-869, SUB 2; Order Closing Dockets (01/31/2007)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS -- Complaint

BellSouth Telecommunications, Inc. -- P-55,
SUB 1714; Order Dismissing Complaint and Closing Docket (10/31/2007)
SUB 1716; Order Dismissing Complaint and Closing Docket (11/21/2007)

Carolina Telephone and Telegraph Company & Central Telephone Co. -- P-7, SUB 969; P-10, SUB 611; Order Dismissing Complaint and Petition and Closing Dockets (10/24/2007)

CTC Exchange Services, Inc. -- P-621, SUB 3 & SUB 4; Order Dismissing Complaints Without Prejudice and Closing Dockets (01/03/2007)

Deltacom, Inc. -- P-500, SUB 24; Order Dismissing Complaint Without Prejudice (01/17/2007)

TelCove Operations, LLC -- P-1020, SUB 7; Order Dismissing Complaint (06/07/2007); Order Canceling Hearing and Closing Docket (06/18/2007)

TELECOMMUNICATIONS - Discontinuance

BellSouth Telecommunications, Inc. -- P-55, SUB 1688; P-869, SUB 4; Order Authorizing Disconnection (04/12/2007); Order Closing Dockets (07/18/2007)

Carolina Telephone and Telegraph Company -- P-7, SUBS 1157 & 1158; P-10, SUBS 783 & 784; P-869, Sub 3; P-1337, SUB 1; Order Authoriz. Disconnection Subject to Notice (04/03/2007); Order Closing Dockets (07/11/2007)

Global NAP's North Carolina -- P-1141, SUB 2; Order Authorizing Disconnection (11/13/2007)

TELECOMMUNICATIONS - EAS

BellSouth Telecommunications Inc. -- P-55, SUB 1703; Order Approving Extended Area Service (05/21/2007)

Carolina Telephone and Telegraph Company -- P-7,
SUB 1154; Order Approving Extended Area Service (02/13/2007)
SUB 1174; Order Approving Extended Area Service (12/10/2007)

TELECOMMUNICATIONS -- Miscellaneous

AT&T Communications of the Southern States -- P-140, SUB 92; Order Granting Numbering Resources (12/21/2007)

BellSouth Telecommunications -- P-55,
SUB 1665 & SUB 1013; Order Allowing Withdrawal Without Prejudice (03/01/2007)
SUB 1679; Order Granting Numbering Resources (01/17/2007)
SUB 1687; Order Granting Numbering Resources (04/04/2007)
SUB 1696; Order Granting Numbering Resources (04/27/2007)
SUB 1705; Order Allowing Migration of Certain Customers (06/12/2007)
SUB 1711; Order Granting Numbering Resources (07/05/2007)
SUB 1712; Order Granting Numbering Resources (07/05/2007)
SUB 1717; Order Granting Numbering Resources (09/12/2007)
SUB 1720; Order Granting Numbering Resources (10/29/2007)
SUB 1724; Order Granting Numbering Resources (11/20/2007)

Carolina Telephone and Telegraph Company -- P-7,
SUB 1152; P-10, SUB 779; P-554, SUB 7; Order Closing Dockets (01/29/2007)
SUB 1166; Order Granting Numbering Resources (06/28/2007)
SUB 1169; Order Granting Numbering Resources (09/05/2007)

ORDERS AND DECISIONS LISTED

TELECOMMUNICATIONS – Miscellaneous

Concord Telephone Company -- P-16,
SUB 228; Order Authorizing Disconnection (03/07/2007)

Consumers' Telephone and Telecom, LLC -- P-832,
SUB 2; Order Allowing Service Termination (05/10/2007); Order Closing Docket (08/02/2007)

MCImetro Access Transmission Services -- P-474, SUB 18; Order Allowing Withdrawal of Arbitration and Closing Docket (04/18/2007)

Sprint Communications -- P-294, SUB 32; Order Grant. Numbering Resources (06/20/2007)

SBC Long Distance -- P-638, SUB 4; Order Authorizing Disconnection of Service (08/30/2007)

Time Warner Telecom -- P-472, SUB 22; Order Granting Numbering Resources (04/27/2007)

TCG of the Carolinas -- P-646, SUB 12; Order Granting Numbering Resources (01/10/2007)

Time Warner Cable Information Services (North Carolina) -- P-1262, SUB 3; Order Granting TWC Petition Under Section 251(F)(1) (06/26/2007)

US LEC of North Carolina, Inc. -- P-561,
SUB 26; Order Granting Numbering Resources (01/12/2007)
SUB 27; Order Granting Numbering Resources (05/14/2007)
SUB 28; Order Granting Numbering Resources (11/20/2007)

Verizon South, Inc. -- P-19,
SUB 477; Order Closing Docket (05/21/2007); Errata Order (05/23/2007)
SUB 517; Order Granting Numbering Resources (09/14/2007)

TELECOMMUNICATIONS – Sale/Transfer

BellSouth Telecommunications -- P-55, SUB 1725; P-638, SUB 5; Order Authorizing Discontinuance or Transfer Subject to Conditions (12/13/2007)

TRANSPORTATION

TRANSPORTATION – Adjustments of Rates/Charges

Rates-Truck -- T-825, SUB 340; Reissued Order Approving Fuel Surcharge (01/05/2007)

Rates-Truck -- T-825, SUB 341; Order Approving Fuel Surcharge (01/17/2007); (01/30/2007); (03/06/2007); (03/20/2007); (04/17/2007); (10/02/2007); (11/19/2007); (12/18/2007)

TRANSPORTATION – Common Carrier Certificate

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION –
Orders Issued

Company	Docket No.	Date
A Few Good Men Moving, Inc.	T-4361, SUB 0	(06/06/2007)
Ark Moving & Storage	T-4367, SUB 0	(09/17/2007)
Absolute Moving & Storage, Inc.	T-4353, SUB 0	(01/17/2007)

ORDERS AND DECISIONS LISTED

ORDER GRANTING APPLICATION FOR CERTIFICATE OF EXEMPTION – *Orders Issued (Continued)*

Company	Docket No.	Date
Affordable Movers	T-4350, SUB 0	(06/20/2007)
Anderson Moving Company	T-4320, SUB 0	(06/20/2007)
Black's Moving and Storage	T-4352, SUB 0	(09/27/2007)
CMTR Moving Services, LLC	T-4355, SUB 0	(02/07/2007)
Doma Moving and Storage LLC	T-4366, SUB 0	(07/02/2007)
Five Star Moving Company	T-4328, SUB 0	(01/10/2007)
GT Moving, Inc.	T-4364, SUB 0	(05/24/2007)
Harrison's Moving & Storage Co	T-4381, SUB 0	(12/05/2007)
Helpful Movers, Inc.	T-4269, SUB 2	(10/12/2007)
Miscellaneous Plus	T-4250, SUB 1	(12/27/2007)
Movers Not Shakers	T-4360, SUB 0	(06/12/2007)
North Star Movers	T-4333, SUB 0	(08/09/2007)
Old Farm Road	T-4380, SUB 0	(12/05/2007)
Pro Movers, LLC	T-4363, SUB 0	(05/24/2007)
Randy Owen Moving Service, LLC	T-4377, SUB 0	(10/26/2007)
South End Moving Company	T-4362, SUB 0	(05/24/2007)
Stor Trans, Inc.	T-4365, SUB 0	(06/26/2007)
T & J Movers	T-4327, SUB 0	(08/22/2007)
Two Men and A Truck; Greenleaf and Associates, Inc., d/b/a	T-4370, SUB 0	(08/17/2007)
Two Men and A Truck of Eastern NC	T-4368, SUB 0	(08/06/2007)
Two Strong Dudes Moving Company, LLC	T-4374, SUB 0	(12/14/2007)
W. E. Smith Moving Co., City Transfer Fayetteville, LLC, d/b/a	T-4376, SUB 0	(10/05/2007)

Triangle Mover's & Shakers -- T-4357, SUB 0; Recommended Order Denying Application (06/01/2007)

TRANSPORTATION - Certificate

Highland Moving & Storage Co.; City Transfer Fayetteville, LLC, d/b/a -- T-4375, SUB 0; Order Granting Certificate of Exemption (10/05/2007)

TRANSPORTATION – Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF EXEMPTION – *Orders Issued*

Company	Docket No.	Date
Ace Moving & Storage Co.	T-4076, SUB 2	(05/16/2007)
Absolute Movers	T-4298, SUB 1	(07/18/2007)
America's Best Moving System Charlotte, LLC	T-4300, SUB 1	(02/27/2007)

ORDERS AND DECISIONS LISTED

ORDER CANCELING CERTIFICATE OF EXEMPTION –
Orders Issued (Continued)

Company	Docket No.	Date
Ark Moving & Storage	T-4286, SUB 1	(09/17/2007)
Black's Pickup, Delivery & Moving Service	T-4213, SUB 1	(10/03/2007)
Carolina Moving & Storage Co.	T-4077, SUB 2	(07/18/2007)
Gilbert Trucking Company	T-891, SUB 3	(06/28/2007)
Highland Moving and Storage Company Inc.	T-1433, SUB 2	(09/24/2007)
Highway Moving	T-4349, SUB 2	(11/13/2007)
Isaac's Moving Service	T-4200, SUB 4	(12/05/2007)
Reliable Furniture Carriers, Inc.	T-4299, SUB 3	(01/10/2007)
Reliable Moving and Storage, Inc.	T-4354, SUB 1	(09/14/2007)
Triad Moving & Storage, Inc.	T-4274, SUB 2	(04/11/2007)
W. E. Smith Moving Co. Inc.	T-907, SUB 5	(09/24/2007)

Byron's Moving & Storage, Inc. -- T-4262, SUB 1; Recommended Order Canceling Certificate of Exemption (03/02/2007)

Carolina 1st Moving & Services, Inc. -- T-4316, SUB 2; Recommended Order Canceling Certificate of Exemption (03/02/2007)

Freeman Boys Courier Service -- T-4331, SUB 1; Recommend. Order Canceling Certificate of Exemption (08/30/2007)

Heads Up Moving & Freight -- T-4334, SUB 1; Recommended Order Canceling Certificate of Exemption (03/02/2007)

SaveUBucks of America -- T-4317, SUB 2; Order Canceling Certificate of Exemption (08/09/2007)

TRANSPORTATION - Contract Carrier Certificate

Smart Move, L.L.C. -- T-4371, SUB 0; Order Granting Application for Certificate of Exemption (09/24/2007)

TRANSPORTATION - Complaint

Matthews Moving Systems, Inc. -- T-2985, SUB 3; Order Dismissing Complaint and Closing Docket (10/22/2007)

TRANSPORTATION - Name Change

Ark Moving & Storage -- T-4367, SUB 1; Order Approving Name Change (10/04/2007)

Hart Moving & Packing Services -- T-4231, SUB 1; Order Approving Name Change (10/19/2007)

Home 2 Home Moving, Pickup & Delivery Co. -- T-4168, SUB 2; Order Approving Name Change (07/27/2007)

Movemart Relocation, Inc. -- T-4248, SUB 1; Order Approving Name Change (04/02/2007)

Triangle Mobile Storage & Moving, LLC -- T-4339, SUB 1; Order Approving Name Change (10/22/2007)

Two Men and A Truck of Eastern NC -- T-4368, SUB 1; Order Approving Name Change (08/09/2007)

ORDERS AND DECISIONS LISTED

TRANSPORTATION - Sale/Transfer

A&L Movers – T-4335, SUB 1; T-4369, SUB 0; Order Approving Transfer and Name Change (10/08/2007)

Blue Ridge Movers, Inc. – T-2138, SUB 4; T-4359, SUB 0; Order Approving Transfer and Name Change (06/22/2007)

WATER AND SEWER

WATER AND SEWER – Bonding

Aqua North Carolina, Inc. -- W-218, SUB 249; Order Approving Corporate Surety Bond and Releasing Bond (04/03/2007)

Bear Den Acres Development Inc. -- W-1040, SUB 5; Order Approving Bond and Surety and Releasing Bond and Surety (02/14/2007)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 306; Order Approving Bond and Surety (07/31/2007)

Fairways Utilities, Inc. -- W-787, SUB 32; W-899, SUB 36; W-981, SUB 10; W-989, SUB 9; W-1032, SUB 9; Order Approving Corporate Surety Bond and Releasing Bond (04/20/2007)

Foxhall Village Utilities, LLC -- W-777, SUB 8; Order Closing Docket (08/06/2007)

Heater Utilities, Inc. - W-274, SUB 631; Order Approving Corporate Surety Bond and Releasing Bond (07/24/2007)

Oakwood Forest Utilities, LLC -- W-1181, SUB 3; Order Closing Docket (08/06/2007)

Town & Country Mobile Home Park -- W-1193, SUB 1; Order Approving Bond and Surety and Releasing Bond and Surety (04/20/2007)

Western Utilities Inc. -- W-229, SUB 6; Order Approving Bond and Surety and Releasing Bond and Surety (03/01/2007)

WATER AND SEWER – Cancellation of Certificate

Asheville Property Management, Inc. -- W-1145, SUB 14; Order Canceling Franchise (12/03/2007)

Bright Leaf Landing Corporation -- W-994, SUB 4; Order Approving Transfer and Canceling Franchise (11/06/2007)

Cavalier Associates LP – W-272, SUB 1; Order Canceling Certificate of Authority (12/11/2007)

Doral Associates L.P. – W-271, SUB 1; Order Canceling Certificate of Authority (12/11/2007)

Hawk Run Development of Asheville Inc. -- W-1238, SUB 6; Order Canceling Franchise (12/03/2007)

WATER AND SEWER – Certificate

ORDER GRANTING FRANCHISE AND APPROVING RATES –
Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc	W-218, SUB 240	(11/30/2007)
Aqua North Carolina, Inc.	W-218, SUB 239	(01/05/2007)

ORDERS AND DECISIONS LISTED

ORDER GRANTING FRANCHISE AND APPROVING RATES – *Orders Issued (Continued)*

Company	Docket No.	Date
Aqua North Carolina, Inc.	W-218, SUB 255	(11/27/2007)
Aqua North Carolina, Inc.	W-218, SUB 260	(11/27/2007)
Aqua North Carolina, Inc.	W-218, SUB 263	(12/20/2007)
Heater Utilities, Inc.	W-274, SUB 503	(06/19/2007)
Heater Utilities, Inc.	W-274, SUB 522	(07/06/2007)
Heater Utilities, Inc.	W-274, SUB 607	(01/26/2007)
Heater Utilities, Inc.	W-274, SUB 610	(09/26/2007)
Heater Utilities, Inc.	W-274, SUB 613	(03/12/2007)
Heater Utilities, Inc.	W-274, SUB 615	(04/30/2007)
Heater Utilities, Inc.	W-274, SUB 616	(04/30/2007)
Heater Utilities, Inc.	W-274, SUB 625	(06/19/2007)
Heater Utilities, Inc.	W-274, SUB 626	(07/06/2007)
Heater Utilities, Inc.	W-274, SUB 635	(09/06/2007)
Heater Utilities, Inc.	W-274, SUB 639	(09/06/2007)
Heater Utilities, Inc.	W-274, SUB 642	(10/16/2007)
Heater Utilities, Inc.	W-274, SUB 643	(10/16/2007)
Heater Utilities, Inc.	W-274, SUB 644	(10/16/2007)
Heater Utilities, Inc.	W-274, SUB 652	(10/16/2007)
Heater Utilities, Inc.	W-274, SUB 653	(12/18/2007)
Heater Utilities, Inc.	W-274, SUB 654	(12/18/2007)
Heater Utilities, Inc.	W-274, SUB 662	(12/13/2007)
SND Properties, LLC	W-1267, SUB 0	(11/27/2007)

Aqua North Carolina, Inc. -- W-218,
SUB 239; Recommended Order (12/28/2007)
SUB 240; Errata Order (12/20/2007)

Banks; Parks – W-1244, SUB 8; Recommend. Order Granting Franchise and Approving Rates (10/03/2007)

Davest Partnership -- W-1269, SUB 0; Order Allowing Withdrawal of Application (07/12/2007)

Heater Utilities, Inc. -- W-274, SUB 642; Errata Order (10/17/2007)

Lake Junaluska Assembly -- W-1274, SUB 0; Order Grant. Franchise and Requiring Customer Notice (12/19/2007)

SND Properties, LLC -- W-1267, SUB 0; Errata Order (12/12/2007)

Total Environmental Solutions, Inc. -- W-1146, SUB 3; Recommended Order Approving Stipulation and Requiring Reports (07/13/2007)

WATER AND SEWER - Complaint

Environmental Maintenance Systems -- W-1054, SUB 8; Order Dismissing Supplemental Complaint and Closing Docket (06/15/2007)

ORDERS AND DECISIONS LISTED

WATER AND SEWER – Contracts/Agreements

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 298; W-1044, SUB 11; W-1151, SUB 3; W-1143, SUB 7; W-1012, SUB 8; W-1013, SUB 5; W-778, SUB 75; W-1058, SUB 3; W-1152, SUB 3; Order Accepting Agreements for Filing and Allowing Utilities to Pay Compensation (01/19/2007)

WATER AND SEWER - Discontinuance

Heater Utilities, Inc. -- W-274, SUB 620; Order Granting Authority to Discontinue Water Service (05/24/2007)

Neuse Crossing Utilities Co.; Whitewood Properties, Inc. d/b/a -- W-1004, SUB 8; Order Canceling Franchise and Releasing Bond and Surety (07/27/2007)

WATER AND SEWER - Emergency Operator

Environmental Maintenance Systems -- W-1054, SUB 9; Order Appointing Emergency Operator and Requiring Customer Notice (11/21/2007)

Mountain Ridge Estates Water System -- W-975, SUB 3; Recommended Order Approving Surcharge and Requiring Customer Notice (11/27/2007)

Sentry Utilities, Inc. -- W-811, SUB 9; Order Appointing Emergency Operator and Requiring Customer Notice (06/29/2007)

Viewmont Acres Water System -- W-856, SUB 7; Order Approving Emergency Assessment and Requiring Customer Notice (08/27/2007)

Village Water; Tobacco Branch Village Water System, Inc. d/b/a -- W-504, SUB 7; Order Approving Surcharge, Scheduling Hearing, and Requiring Customer Notice (12/18/2007)

WATER AND SEWER - Filings Due per Order or Rule

Scientific Water and Sewerage Corporation -- W-176, SUB 33; Order Accepting Report and Closing Docket (01/03/2007)

WATER AND SEWER – Merger

Aqua North Carolina, Inc. -- W-218, SUB 250; W-177, SUB 53; W-200, SUB 48; Order Approving Merger (06/29/2007)

Carolina Water Service of North Carolina -- W-354, SUB 304; W-809, SUB 3; W-936, SUB 2; W-962, SUB 2; W-962, SUB 3; W-703, SUB 2; W-703, SUB 3; Order Approving Merger (01/19/2007)

WATER AND SEWER - Rate Increase

Carolina Water Service of North Carolina -- W-354, SUB 266; Order Closing Docket and Transferring Outstanding Issues (03/02/2007)

Christmount Christian Assembly, Inc. -- W-1079, SUB 6; Order Granting Rate Increase and Requiring Customer Notice (01/24/2007)

Enviracon Utilities, Inc. – W-1236, SUB 2; Order Adjusting Temporary Rate Component Relating to Tank Collapse Recovery (04/05/2007)

GGCC Utility, Inc. -- W-755, SUB 5; Order Granting Rate Increase, Canceling Public Hearing, and Requiring Customer Notice (07/12/2007)

Parks Banks – W-360, SUB 6; Recommended Order Granting Franchise and Approving Rates (10/03/2007)

WATER AND SEWER - Rate Increase *(Continued)*

Porters Neck Co., Inc. -- W-1059, SUB 5; Order Dismissing Application, Canceling Hearing, Requiring Customer Notice, and Closing Docket (04/03/2007)

Prior Construction Co. -- W-567, SUB 6; Recommended Order Granting Rates and Requiring Customer Notice (02/12/2007); Order Allowing Recommended Order to Become Effective and Final (02/12/2007)

Scientific Water and Sewerage Corp. – W-176, SUB 32; W-176, SUB 29; Order Requiring Bond (10/29/2007)

Water Quality Services, Inc. -- W-1099, SUB 11; Recommended Order Granting Partial Rate Increase and Requiring Customer Notice (08/09/2007)

904 Georgetown Treatment Plant, LLC -- W-1141, SUB 4; Order Granting Partial Rate Increase, Approving Agreements, and Requiring Customer Notice (09/25/2007)

WATER AND SEWER – Sale/Transfer

A & D Water Service, Inc. -- W-1049, SUB 12; W-1024, SUB 3; Recommended Order Granting Transfer, Approving Rates, and Requiring Customer Notice (11/05/2007)

Aqua North Carolina, Inc. -- W-218, SUB 245; W-1101, SUB 3; Recomm. Order Grant. Transfer, Grant. Rates Increase, and Requir. Customer Notice (06/19/2007); Order Allowing Recommend. Order to Become Effective and Final (08/20/2007); Order Releasing Bond and Closing Dockets (11/06/2007)

ARC AF Utilities, LLC -- W-1252, SUB 0 ; W-1200, SUB 2; Order Approving Transfer, Approving Rates, and Requiring Customer Notice (07/30/2007)

Cowan Valley Estates Water System -- W-829, SUB 4; Order Approving Transfer (Effective upon Superior Court Order) and Requiring Customer Notice (05/21/2007)

Cook, Jr.; William Edward -- W-1262, SUB 0; W-688, SUB 6; Recommended Order Granting Transfer of Franchise and Increase In Rates (01/03/2007)

CTC Brick Landing, LLC – W-1231, SUB 1; W-1231, SUB 2; W-1231, SUB 3; W-218, SUB 234; W-1273, SUB 0; Order Rescinding Order of August 8, 2006, Closing Dockets, Approving Temporary Operatng Authority (06/29/2007)

Gullzar Properties, LLC -- W-1266, SUB 0; W-1112, SUB 5; Order Accepting Bond, Approving Transfer and Rates, and Requiring Customer Notice (08/10/2007)

Rolesville MHP, LLC -- W-1162, SUB 1; W-1270, SUB 0; Order Approving Transfer of Franchise, Approving Bond, Approving Rates, and Requiring Notice (08/27/2007)

WATER AND SEWER – Show Cause

Orchard View Park -- W-1258, SUB 1; Recommended Order Denying the Public Staff's Motion to Show Cause (04/12/2007)

WATER AND SEWER – Tariff Revision for Pass-Through

ORDER APPROVING TARIFF REVISION –
Orders Issued

Company	Docket No.	Date
Banks, Parks	W-1244, SUB 9	(11/05/2007)
Carolina Water Service, Inc. of North Carolina	W-354, SUB 308	(07/27/2007)
Christmount Christian Assembly, Inc.	W-1079, SUB 7	(08/15/2007)

ORDERS AND DECISIONS LISTED

ORDER APPROVING TARIFF REVISION –
Orders Issued (Continued)

Company	Docket No.	Date
Chapman, Roy & Betty	W-1247, SUB 2	(12/11/2007)
Chatham Utilities, Inc.	W-1240, SUB 2	(09/26/2007)
Jefferson Landing, LLC	W-1255, SUB 1	(02/21/2007)
Locust Grove Mobile Home Park	W-1106, SUB 8	(11/06/2007)
Meco Utilities Inc.	W-1166, SUB 4	(12/03/2007)
Metro Water Systems, Inc.	W-1109, SUB 10	(11/06/2007)
Town & Country MHP; Vida Reid, d/b/a	W-1193, SUBS 2 & 3	(05/10/2007)
Viewmont Acres	W-856, SUB 7	(02/21/2007)
Winkler, Carl K.	W-1206, SUB 5	(11/06/2007)

Holiday Island Property Owners Assoc. -- W-386, SUB 17; Order Granting Revised Sewer Connection Charge (12/19/2007)

Joyceton Water Works, Inc. -- W-4, SUB 11; Order Approving Tariff Revision and Requiring Customer Notice (06/05/2007)

Scientific Water and Sewerage Corp. -- W-176,
SUB 35; Order Deny. Request for a "Flow Through" of Bill Collect. Charge (06/14/2007)
SUB 36; Order Approving Tariff Revision and Requiring Customer Notice (07/02/2007)

WATER AND SEWER – Contiguous Water Extension

ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES --
Orders Issued

Company	Docket No.	Date
Aqua North Carolina, Inc.		
(Apple Grove Subdivision)	W-218, SUB 262	(12/11/2007)
(Ridgecrest Subdivision – Phase 2)	W-218, SUB 248	(04/26/2007)
(Lennox Woods Subdivision – Phase 3)	W-218, SUB 254	(08/17/2007)
(Sterlingshire Subdivision -- Phase 2 & 3)	W-218, SUB 256	(11/27/2007)
(EPES Trucking Co.)	W-218, SUB 259	(11/27/2007)
Willows Glen Subdiv. – Phase 2)	W-218, SUBS 205 & 165	(03/30/2007)
(Point South & Beau Rivage Subdivs.)	W-218, SUBS 223 & 165	(03/30/2007)
Carolina Water Service, Inc. of North Carolina		
(Reedy Creek Run Subdivision)	W-354, SUB 270	(01/26/2007)
(Julian Meadows Subdivision)	W-354, SUB 273	(08/16/2007)
(Brookstead Meadows Subdivision)	W-354, SUB 281	(02/14/2007)
(Oliver Subdiv. At Whispering Pines)	W-354, SUB 301	(08/16/2007)
(Bent Tree Subdiv. – Phases 2 & 3)	W-354, SUB 302	(01/26/2007)
(Princess Gate Subdivision)	W-354, SUB 303	(09/04/2007)

ORDERS AND DECISIONS LISTED

ORDER RECOGNIZING CONTIGUOUS EXTENSION AND APPROVING RATES – *Orders Issued (Continued)*

Company	Docket No.	Date
Fairways Utilities, Inc.		
(Windswept Subdivision – Phase 2)	W-787, SUB 24	(05/01/2007)
(Windspray Subdivision)	W-787, SUB 27	(06/01/2007)
(Nautical Green Subdivision)	W-787, SUB 30	(04/25/2007)
Heater Utilities, Inc.		
(Pineville East Subdiv. – Phase 1)	W-274, SUB 558	(04/30/2007)
(Northfarm Cottages Subdiv. – Phase 3)	W-274, SUB 562	(01/26/2007)
(Chapel Ridge Subdiv. – Phase 3)	W-274, SUB 571	(06/19/2007)
(Olde Milburnie Crossing Subdiv.)	W-274, SUB 585	(12/13/2007)
(Northfarm Subdiv. – Section 3)	W-274, SUB 586	(01/26/2007)
(Pineville West Subdiv. – Phase 2)	W-274, SUB 604	(04/04/2007)
(Hasentree Subdiv. – Phase 3)	W-274, SUB 611	(03/12/2007)
(Cane Creek Subdiv. – Phase 2-R)	W-274, SUB 612	(03/12/2007)
(Millcreek West Subdiv. – Section 4)	W-274, SUB 614	(07/06/2007)
(Greycliff Subdiv. – 12 additional lots)	W-274, SUB 617	(04/30/2007)
(Pebble Bay Subdiv. – Phases 3 & 4)	W-274, SUB 618	(05/10/2007)
(Hampton Park Subdiv. – Phase 2)	W-274, SUB 619	(04/30/2007)
(Still Creek Run Subdivision)	W-274, SUB 621	(04/30/2007)
(Crystal Creek Subdivision)	W-274, SUB 622	(05/25/2007)
(Northfarm Subdivision – Section 4)	W-274, SUB 624	(09/05/2007)
(Hasentree Subdiv. – Phase 7)	W-274, SUB 628	(09/05/2007)
(Pebble Bay Subdiv. – Phase 5)	W-274, SUB 630	(09/05/2007)
(Hillington West Subdiv. – Sect. 6 & 7)	W-274, SUB 632	(09/05/2007)
(Blalock Glen Subdivision)	W-274, SUB 633	(09/05/2007)
(Woodhurst Subdivision)	W-274, SUB 634	(09/05/2007)
(Hasentree Subdivision – Phase 6A)	W-274, SUB 636	(09/26/2007)
(Ridgecrest/Wellesley Place Subdiv)	W-274, SUB 638	(09/06/2007)
(Steven's Oaks Subdiv. – Phase 3)	W-274, SUB 640	(09/26/2007)
(Estates at Barton's Creek Subdiv.)	W-274, SUB 641	(09/26/2007)
(Turner Farms Subdiv. – Phases 9 & 10)	W-274, SUB 649	(11/05/2007)
((The Estates at West Oaks Subdiv.)	W-274, SUB 650	(11/05/2007)
(Rose Hill Subdivision – Phase 2)	W-274, SUB 651	(11/05/2007)
(High Grove Subdiv. – Phase 2)	W-274, SUB 655	(11/05/2007)
(Glens at MacTavish Subdiv.)	W-274, SUB 656	(11/05/2007)
(Fieldstone/Coldsprings Subdiv. – Phase 3)	W-274, SUB 657	(11/05/2007)
(Swallow Cove Subdivision)	W-274, SUB 665	(12/13/2007)
Meadowlands Development, LLC		
Meadowlands Subdivision)	W-1259, SUB 1	(03/12/2007)
Water Resource Management, Inc.		
(Hawks Peak/Hawks Peak South Condos)	W-1073, SUB 3	(04/24/2007)

Carolina Water Service, Inc. of North Carolina -- W-354, SUB 303; Errata Order (09/06/2007)

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WATER AND SEWER – Water Restriction

Carolina Water Service of North Carolina -- W-354, SUB 307;

Order Restrict. Water Use and Requiring Customer Notice (The Harbour/The Point Subdivision) (06/18/2007)

Order Extending Restriction of Water Use and Requiring Customer Notice (10/15/2007)

Order Granting Authority to Terminate Water Utility Service upon Further Violation:

(Courtland Propt.) (08/28/2007)

(B. & T. Barr) (08/28/2007)

(Charles Meeker) (08/28/2007)

(Ed Martin); (08/28/2007)

(Jan Noone) (08/28/2007)

(Matt Kenseth) (08/28/2007)

(Sonja Cole) (08/28/2007)

Order Denying Request for Exemption to Water Restrictions (10/03/2007)

Heater Utilities, Inc. -- W-274, SUB 645;

Order Restricting Water Use and Requiring Customer Notice (Bayleaf Master System) (08/13/2007)

Order Denying Request for Exception to Water Restrictions:

(Mr. & Mrs. Dixon) (09/17/2007)

(Mr. & Mrs. Elliott Kopp) (09/17/2007)

(Mr. & Mrs. Ziperski) (09/17/2007)

(Mr. Berasi) (09/17/2007)

(Mr. Phil Miller) (09/17/2007)

(Mr. William Zaun) (09/17/2007)

Order Denying Request for Exemption to Water Restrictions (Bayleaf Master System) (10/03/2007)

Order Granting Authority to Terminate Water Utility Service Upon Further Violation:

(George Bell) (10/10/2007)

(James Ziperski) (10/10/2007)

(Patrick Smith) (10/10/2007)

(Phil Miller) (10/10/2007)

(Robert Allan) (10/10/2007)

(Shanni Harrison) (10/10/2007)

Order Denying Request for Exception for Water Restrictions (Bayleaf Master System) (10/30/2007); (10/30/2007)

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RESALE OF WATER AND SEWER

RESALE OF WATER AND SEWER – Certificate

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Company	Docket No.	Date
Abberly Green-Mooresville Phase II LP	WR-686, SUB 0	(11/01/2007)
Abbington Place/Charlotte (Phase II	WR-621, SUB 0	(06/26/2007)
AIMCO Williamsburg Manor, LLC	WR-675, SUB 0	(10/31/2007)
Alpha Mill, LLC	WR-559, SUB 0	(03/05/2007)
Apartment REIT Residences at Braemar	WR-655, SUB 0	(09/06/2007)
AR3NC, LLC	WR-597, SUB 0	(06/13/2007)
Asheville Eastwood Apartments, LLC	WR-602, SUB 0	(06/18/2007)
Ashford SPE, LLC	WR-555, SUB 0	(03/05/2007)
Battleground North Apartments, LLC	WR-672, SUB 0	(10/16/2007)
BBR/Clearwater 1, LLC	WR-705, SUB 0	(12/12/2007)
BBR/Quail Hollow, LLC	WR-615, SUB 0	(06/18/2007)
BEL-EQR I Limited Partnership	WR-676, SUB 0	(10/31/2007)
BEL-EQR III Limited Partnership	WR-678, SUB 0	(10/24/2007)
BEL-EQR IV Limited Partnership		
(Kimmerly Glen Apartments)	WR-679, SUB 0	(10/24/2007)
(McAlpine Ridge Apartments)	WR-679, SUB 1	(10/24/2007)
Berkeley Apartments, Inc.	WR-581, SUB 0	(05/08/2007)
Blakeney Apartments, LLC	WR-658, SUB 0	(09/21/2007)
Bluff Ridge Associates Limited Partnership	WR-645, SUB 0	(08/09/2007)
Bouwfonds Pavilion Crossings I, LLC	WR-599, SUB 0	(05/31/2007)
Bouwfonds Pavilion Crossings II, LLC	WR-598, SUB 0	(05/31/2007)
BPIP, LLC	WR-562, SUB 0	(03/28/2007)
BRC Tolar Road, LLC	WR-652, SUB 0	(08/30/2007)
Brier Creek FC, LLC	WR-650, SUB 0	(09/12/2007)
Brightwood Crossing Apartments, LLC	WR-543, SUB 0	(01/09/2007)
Burd Properties of Fayetteville, LLC		
(Meadowbrook at Kings Grant Apts.	WR-585, SUB 0	(05/08/2007)
(Carlson Bay Apartments)	WR-585, SUB 1	(05/08/2007)
(Stoney Ridge Apartments)	WR-585, SUB 2	(05/08/2007)
Capreit Hidden Oaks Limited Partnership	WR-682, SUB 0	(10/16/2007)
Carlyle Place, LLC	WR-647, SUB 0	(10/09/2007)
Carolina Parks, LLC	WR-591, SUB 0	(05/24/2007)
Cary Parkway Marquis, L. P.	WR-522, SUB 0	(01/31/2007)
Central Park Associates	WR-695, SUB 0	(11/29/2007)
Charleston Place, LLC	WR-700, SUB 0	(12/11/2007)
Charter Properties, Inc.	WR-688, SUB 0	(11/01/2007)
Citiside Booth, LLC, et al.	WR-698, SUB 0	(12/06/2007)
City View Apartments, LLC	WR-702, SUB 0	(12/11/2007)

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Company	Docket No.	Date
Colonial Realty Limited Partnership		
(Ayrsley Apartments)	WR-437, SUB 3	(10/09/2007)
(Colonial Grand at Huntersville Apts)	WR-437, SUB 4	(10/09/2007)
Concord 5, LLC		
(Hampton Corners Apartments)	WR-579, SUB 0	(05/08/2007)
(Parkway Crossing Apartments)	WR-579, SUB 1	(05/08/2007)
(Crown Ridge Apartments)	WR-579, SUB 2	(05/08/2007)
((Coopers Ridge Apartments)	WR-579, SUB 3	(05/03/2007)
Concord 6, LLC		
(River Park Apartments)	WR-580, SUB 0	(05/03/2007)
(Forest Ridge Apartments)	WR-580, SUB 1	(05/02/2007)
(Crossroads at Village Park Apts.)	WR-580, SUB 2	(05/02/2007)
(Alexander Place Apartments)	WR-580, SUB 3	(05/03/2007)
(Hampton Forest Apartments)	WR-580, SUB 4	(05/03/2007)
(The Village at Brierfield Apts.)	WR-580, SUB 5	(05/02/2007)
Cornelius Development, LLC	WR-640, SUB 0	(08/17/2007)
Courtney Estates Holdings, LLC	WR-572, SUB 0	(04/05/2007)
Courtney Reserve Apartments, LLC	WR-553, SUB 0	(02/20/2007)
Covington Meridian Acquisitions, et al.	WR-651, SUB 0	(08/30/2007)
CS 102 Brier Creek LP	WR-574, SUB 0	(05/16/2007)
CWS Palm Valley Ballantyne, et al.	WR-343, SUB 2	(04/13/2007)
DDRTC Birkdale Village, LLC	WR-699, SUB 0	(12/07/2007)
Donathan Cary Limited Partnership	WR-558, SUB 0	(03/05/2007)
Durham Apartment Company, LLC	WR-575, SUB 0	(04/16/2007)
Eagle Point Village Apartments, LLC	WR-671, SUB 0	(10/10/2007)
Edge Creek Crossroads, L.P.	WR-654, SUB 0	(12/18/2007)
EEA-Wildwood, LLC	WR-629, SUB 0	(08/01/2007)
Eggleston; Matthew and Lora	WR-578, SUB 0	(04/27/2007)
EQR - Fankey 2004 Limited Partnership	WR-681, SUB 0	(10/16/2007)
EQR – Raleigh Vistas, Inc.	WR-674, SUB 0	(10/31/2007)
EQR- Autumn River, LLC	WR-673, SUB 0	(10/16/2007)
EQR-The Plantations (NC) Vistas, Inc.	WR-683, SUB 0	(10/24/2007)
ERP Operating Limited Partnership	WR-18, SUB 143	(10/10/2007)
Fairfield Autumn Woods, LLC	WR-620, SUB 0	(06/26/2007)
Fairfield Crabtree Valley LP	WR-692, SUB 0	(11/21/2007)
Fairfield North Park, LP	WR-551, SUB 0	(02/08/2007)
Fairfield Oak Pointe LLC	WR-656, SUB 0	(09/20/2007)
Fairfield Olde Raleigh, LLC	WR-552, SUB 0	(02/20/2007)
Fairfield RTP Limited Partnership	WR-586, SUB 0	(05/17/2007)
Fairfield Windsor Falls, LLC	WR-628, SUB 0	(07/18/2007)
Forest Durham Apartments, LLC et al.	WR-616, SUB 0	(06/26/2007)

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ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES -- *Orders Issued (Continued)*

Company	Docket No.	Date
Freedom Property Investors, LLC		
(Bavarian Point Private Community)	WR-589, SUB 0	(05/16/2007)
(Carolina Pines Private Community)	WR-589, SUB 1	(05/16/2007)
Fund IX CP Charlotte, LLC	WR-691, SUB 0	(11/01/2007)
GMC Charlotte II, LLC	WR-669, SUB 0	(10/16/2007)
Gray Property 2205, LLC	WR-659, SUB 0	(09/21/2007)
Greenfield Village, L.L.C	WR-549, SUB 0	(01/31/2007)
Greystone Heritage, LLC	WR-519, SUB 0	(04/27/2007)
Griffin and Sons Investments, LLC	WR-631, SUB 0	(07/26/2007)
GS Village, LLC	WR-564, SUB 0	(03/29/2007)
Hanover Terrace, LLC	WR-622, SUB 0	(06/26/2007)
Heather Ridge Condominiums, LLC	WR-660, SUB 0	(10/02/2007)
Highlands-Raleigh, LLLP	WR-639, SUB 0	(08/01/2007)
Highpoint Associates, LLC	WR-570, SUB 0	(04/05/2007)
HMS SouthPark Residential LLC	WR-668, SUB 0	(10/16/2007)
ITAC 220, LLC	WR-582, SUB 0	(04/27/2007)
Juniper Cumberland, LLC	WR-670, SUB 0	(10/10/2007)
Kings Bridgetown Bay Apartments, LLC	WR-556, SUB 0	(03/05/2007)
Koury Corporation		
(North Elm Apartments)	WR-595, SUB 0	(06/07/2007)
(North Elm Apartments)	WR-595, SUB 1	(09/27/2007)
(Yester Oaks Apartments)	WR-595, SUB 2	(12/05/2007)
KPCLIC, LLC	WR-573, SUB 0	(04/16/2007)
Lake Cameron, LLC	WR-546, SUB 0	(01/31/2007)
Lakeshore Apartments, LLC	WR-649, SUB 0	(08/24/2007)
Laurel in the Pines, LLC	WR-544, SUB 0	(01/09/2007)
Legacy Matthews, LLC	WR-568, SUB 0	(04/05/2007)
Legacy Park, LLC	WR-646, SUB 0	(10/09/2007)
Lichtin Development, LLC	WR-630, SUB 0	(07/03/2007)
Litchford Park LLC	WR-588, SUB 0	(05/23/2007)
Lynndale Apartments, Inc.	WR-627, SUB 0	(07/03/2007)
Metropolitan Development of Apex LLC	WR-577, SUB 0	(06/18/2007)
Mid-America Apartments, LP	WR-22, SUB 18	(07/03/2007)
Maggard, David	WR-632, SUB 0	(07/03/2007)
Magnolia Station Apartments, LLC	WR-661, SUB 0	(10/02/2007)
Mallard Glen Apartments, LLC	WR-662, SUB 0	(10/02/2007)
Matthews Reserve, LLC	WR-557, SUB 0	(03/05/2007)
Meadowbrook Village of Forest City, LLC	WR-566, SUB 0	(04/05/2007)
Mission Battleground Park LeaseCo	WR-696, SUB 0	(11/30/2007)
Mission Stadler Place LeaseCo, LLC	WR-701, SUB 0	(12/12/2007)

ORDER GRANTING CERTIFICATE OF AUTHORITY AND APPROVING RATES -- *Orders Issued (Continued)*

Company	Docket No.	Date
ML North Carolina Apartments LP		
(Sommerset Place Apartments)	WR-680, SUB 0	(10/24/2007)
(Duraleigh Woods Apartments)	WR-680, SUB 1	(10/31/2007)
(Sailboat Bay Apartments)	WR-680, SUB 2	(10/31/2007)
MLQ-MLL, LLC	WR-623, SUB 0	(07/11/2007)
Morganton Trading Company, LLC	WR-548, SUB 0	(01/31/2007)
National Champion Real Estate, LLC	WR-600, SUB 0	(05/31/2007)
New Haw Creek Associates	WR-624, SUB 0	(07/03/2007)
New Haw Creek Section II Associates	WR-625, SUB 0	(07/03/2007)
New Tiffany Square Associates, LLC	WR-592, SUB 0	(06/14/2007)
NNN Beechwood Apartments, LLC et al.	WR-664, SUB 0	(10/09/2007)
NNN Enclave Apartments, LLC, et al.	WR-560, SUB 0	(03/12/2007)
NNN Landing Apartments, LLC	WR-545, SUB 0	(02/20/2007)
NNN Springfield Apartments, LLC, et al.	WR-663, SUB 0	(10/09/2007)
Norwalk Street Partners, LLC	WR-653, SUB 0	(09/12/2007)
Pine Terrace Mobile Home Park	WR-554, SUB 0	(06/26/2007)
Providence Park Apartments II LLC	WR-687, SUB 0	(11/14/2007)
Racine Drive Associates, LLC	WR-626, SUB 0	(07/18/2007)
S. E. Portfolio Apartments, LLC	WR-505, SUB 0	(01/17/2007)
Sagebrush Andover Woods Mgmt. LLC	WR-693, SUB 0	(11/21/2007)
Sagebrush Courtney Oaks Apts., LLC	WR-567, SUB 0	(03/28/2007)
Sagebrush Waterford Creek Apts. et al.	WR-542, SUB 0	(01/02/2007)
SH Pool A Sunstone, LLC	WR-694, SUB 0	(11/28/2007)
South Terrace Apts. North Carolina, LLC	WR-689, SUB 0	(11/02/2007)
Southern Oaks Apartments, LLC	WR-587, SUB 0	(06/26/2007)
Southpoint Village, LLC	WR-583, SUB 0	(05/08/2007)
Sterling Morrison Apartments, LLC	WR-643, SUB 0	(08/24/2007)
Summit Grandview, LLC	WR-547, SUB 0	(02/08/2007)
SVF Weston Lakeside, LLC	WR-601, SUB 0	(06/19/2007)
Terrace Mews Associates	WR-569, SUB 0	(04/16/2007)
The Fairway Apartments, et al	WR-565, SUB 0	(03/28/2007)
The Grand on Julian, LLC	WR-690, SUB 0	(11/01/2007)
The Village at Carver Falls II	WR-563, SUB 0	(04/10/2007)
TIC Adams Farm, LLC et al	WR-667, SUB 0	(10/10/2007)
TIC Bridford Lake, LLC et al	WR-666, SUB 0	(10/10/2007)
Trotter & Allen Construction Co., Inc.	WR-593, SUB 0	(05/23/2007)
Troy Meadows, LLC	WR-550, SUB 0	(02/19/2007)
Tryon Village, LLC	WR-576, SUB 0	(04/16/2007)
USA Courtney Creek LeaseCo, LLC	WR-642, SUB 0	(09/12/2007)
USA Parkside 1, LLC	WR-381, SUB 1	(06/26/2007)
Value Family Properties-Holiday City	WR-540, SUB 0	(01/02/2007)
Wakefield Affordable Housing, LLC	WR-685, SUB 0	(11/07/2007)

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Westdale Arrowhead Crossing NC	WR-634, SUB 0	(07/18/2007)
Westdale Chase on Monroe NC, LLC	WR-635, SUB 0	(07/11/2007)
Westdale Sabal Point NC, LLC	WR-636, SUB 0	(07/18/2007)
Westdale Willow Glen NC, LLC	WR-633, SUB 0	(07/18/2007)
Westridge Place, LLC	WR-637, SUB 0	(07/26/2007)
Whitehurst/Countryview MHP	WR-657, SUB 0	(09/20/2007)
Windsor Burlington, LLC	WR-594, SUB 0	(06/13/2007)
Young Real Estate Investments, LLC	WR-584, SUB 0	(05/23/2007)
Zell; Samuel & Robert Lurie	WR-684, SUB 0	(10/16/2007)
4209 Lassiter Mill Rd. Apts. Investors	WR-571, SUB 0	(04/05/2007)
82 Magnolia Chapel Hill, LLC	WR-703, SUB 0	(12/12/2007)

Abberly Green-Mooresville-Phase II LP -- WR-686, SUB 0; Errata Order (12/31/2007)

AIMCO Williamsburg Manor, LLC -- WR-675, SUB 0; Errata Order (12/31/2007)

ARC Communities 11, LLC -- WR-534, SUB 0; W-777, SUB 7; W-1251, SUB 0; Order Granting Certificate of Author., Approv. Transfer, and Cancel. Franchise (07/30/2007)

ARCML06 LLC -- WR-532, SUB 0; W-1181, SUB 2; W-1253, SUB 0; Order Granting Certificate of Author., Approv. Transfer and Canceling Franchise (07/30/2007)

BEL-EQR IV Limited Partnership -- WR-679, SUB 1; Errata Order (11/21/2007)

Capreit Hidden Oaks Limited Partnership -- WR-682, SUB 0; Errata Order (11/21/2007)

EQR - Fankey 2004 Limited Partnership -- WR-681, SUB 0; Errata Order (11/21/2007)

Graves Evans Enterprises, Inc. -- WR-529,
- SUB 0; W-1144, SUB 5; Order Gran.t. Certif. of Author., Approv. Rates, and Cancel. Franchise (01/09/2007)
- SUB 0; Errata Order (02/02/2007)
- SUB 0; Errata Order (02/06/2007)

Koury Corporation -- WR-595, SUB 2; Errata Order (12/05/2007)

Legacy Matthews, LLC -- WR-568, SUB 0; Errata Order (04/09/2007)

Sagebrush Waterford Creek Apts., LLC. -- WR-542, SUB 0; Errata Order (01/04/2007)

Juniper Brannon Park, LLC -- WR-704, SUB 0; WR-429, SUB 1; Order Granting Transfer of Certificate of Authority and Approving Rates (12/12/2007)

Plantation Park Apartments -- WR-644, SUB 0; WR-515, SUB 1; Order Granting Transfer of Certificate of Authority and Approving Rates (08/21/2007)

Whitehurst/Countryview MHP -- WR-657, SUB 0; Reissued Order Granting Certificate of Authority and Approving Rates (09/26/2007)

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RESALE OF WATER AND SEWER -- Cancellation of Certificate

ORDER CANCELING CERTIFICATE OF AUTHORITY -- *Orders Issued*

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AERCofNC, LLC	WR-332, SUB 1	(02/14/2007)
ASN Pinnacle, LLC	WR-218, SUB 3	(09/05/2007)
Autumn Woods Apartments, LLC	WR-510, SUB 1	(06/26/2007)
Brown Investment Properties	WR-46, SUB 13	(12/12/2007)
Beechwood Triad Apt. Portfolio, LLC	WR-496, SUB 1	(08/15/2007)
Benj. .E .Sherman & Sons, Inc. as Managing Agent for BES Crabtree Fund I&II	WR-159, SUB 5	(11/21/2007)
Birkdale Village, LLC	WR-125, SUB 3	(01/24/2007)
Bradford Place Limited Partnership	WR-67, SUB 3	(01/18/2007)
Braemar Housing Limited Partnership	WR-282, SUB 2	(08/07/2007)
Carmel Valley Associates	WR-10, SUB 2	(01/09/2007)
Cavalier Associates, LP	WR-272, SUB 1	(12/11/2007)
CDC Pineville, LLC	WR-86, SUB 5	(01/18/2007)
Couch-Oxford Associates LP	WR-148, SUB 2	(08/21/2007)
Courtney Creek Apartment Investors, LLC	WR-188, SUB 1	(01/24/2007)
Courtney Estates Apartments, LLC	WR-311, SUB 2	(03/16/2007)
Courtney Oaks Apartments, LLC	WR-315, SUB 1	(01/09/2007)
Covington Meridian LeaseCo, LLC	WR-425, SUB 2	(08/01/2007)
CWS Crossroads 2000, LP	WR-351, SUB 3	(07/31/2007)
CWS Apartment Homes, LLC	WR-343, SUB 1	(01/30/2007)
Cypress Pond at Porter's Neck, LLC	WR-322, SUB 1	(08/08/2007)
Dekalb Street Apartments, LLC	WR-195, SUB 1	(05/08/2007)
Doral Associates, LP	WR-271, SUB 1	(12/11/2007)
DRP Stoney Ccreek, LLC	WR-32, SUB 6	(03/05/2007)
Equity Residential Properties Operating, L.P.		
(Sommerset Place Apartments)	WR-18, SUB 116	(09/11/2007)
(Berkshire Place Apartments)	WR-18, SUB 117	(09/11/2007)
(Creekwood Apartments)	WR-18, SUB 118	(09/11/2007)
(Cross Creek Apartments)	WR-18, SUB 119	(09/11/2007)
Equity Residential Properties Operating, L.P.		
(Hunt Club Apartments)	WR-18, SUB 120	(09/11/2007)
(Kimmerly Glen Apartments)	WR-18, SUB 121	(09/11/2007)
(McAlpine Ridge Apartments)	WR-18, SUB 122	(09/11/2007)
(The Oaks Apartments)	WR-18, SUB 123	(09/11/2007)
(The Point Apartments)	WR-18, SUB 124	(09/11/2007)
(The Regency Apartments)	WR-18, SUB 125	(09/11/2007)
(Winterwood Apartments)	WR-18, SUB 126	(09/11/2007)
(Autumn River Apartments)	WR-18, SUB 128	(09/12/2007)
(Bridgeport Apartments)	WR-18, SUB 129	(09/12/2007)
(Duraleigh Woods Apartments)	WR-18, SUB 130	(09/12/2007)
(Hidden Oaks Apartments)	WR-18, SUB 131	(09/12/2007)

ORDER CANCELING CERTIFICATE OF AUTHORITY –
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Company	Docket No.	Date
Equity Residential Properties Operating, L.P.		
(Legends at Preston Apartments)	WR-18, SUB 132	(09/12/2007)
(Sailboat Bay Apartments)	WR-18, SUB 133	(09/12/2007)
(Woodbridge Apartments)	WR-18, SUB 134	(09/12/2007)
(Bainbridge Apartments)	WR-18, SUB 135	(09/12/2007)
(Laurel Ridge Apartments)	WR-18, SUB 136	(09/12/2007)
(Rock Creek Apartments)	WR-18, SUB 137	(09/12/2007)
(Misty Woods Apartments)	WR-18, SUB 138	(09/12/2007)
(English Hills Apartments)	WR-18, SUB 139	(09/12/2007)
(East Pointe Apartments)	WR-18, SUB 140	(09/12/2007)
(Bridford Lakes Apartments)	WR-18, SUB 141	(09/12/2007)
(Adams Farm Apartments)	WR-18, SUB 142	(09/12/2007)
Estates at Chapel Hill, LLC	WR-89, SUB 2	(12/12/2007)
EWGP LTD	WR-330, SUB 2	(06/18/2007)
Fairfield Poplar Place, LP	WR-473, SUB 1	(04/19/2007)
Fayetteville Apartments, LLC	WR-441, SUB 1	(03/20/2007)
FGR Dilworth, LLC	WR-184, SUB 2	(02/14/2007)
Forest Durham Management, LLC	WR-358, SUB 2	(03/16/2007)
Forest Ridge, LLC	WR-171, SUB 2	(02/07/2007)
Greensboro-Oxford Associates LP	WR-122, SUB 3	(01/17/2007)
Hampton Corners, LLC	WR-196, SUB 1	(05/08/2007)
Hampton Forest, LLC	WR-204, SUB 2	(05/03/2007)
Hidden Forest Drive, LLC	WR-173, SUB 2	(02/07/2007)
Highway 49, LLC	WR-172, SUB 2	(02/07/2007)
K&S Auburn, LLC and EYC Auburn, LLC	WR-157, SUB 3	(11/02/2007)
Katahdin Properties Trust, LLC	WR-217, SUB 3	(01/02/2007)
Kings Grant Fayetteville, LLC	WR-442, SUB 1	(03/20/2007)
Legacy Meadows Limited Partnership	WR-80, SUB 5	(03/16/2007)
Littlefield Enterprises Concord, LLC	WR-255, SUB 2	(05/08/2007)
Littlefield Enterprises Kannapolis, LLC	WR-264, SUB 2	(05/03/2007)
Littlefield Enterprises Mooresville, LLC	WR-238, SUB 2	(05/03/2007)
Lofts at Lakeview, LP	WR-440, SUB 1	(09/11/2007)
Protea Berkeley Carolina, LP	WR-181, SUB 5	(03/06/2007)
Regent Morrisville, LLC	WR-301, SUB 1	(06/04/2007)
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