NINETY-FIRST REPORT

OF THE

NORTH CAROLINA

UTILITIES COMMISSION

ORDERS AND DECISIONS

ISSUED FROM
JANUARY 1, 2001 THROUGH DECEMBER 31, 2001

NINETY-FIRST REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 2001, through December 31, 2001

Jo Anne Sanford, Chair

Judy Hunt, Commissioner

J. Richard Conder, Commissioner

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

*Lorinzo L. Joyner, Commissioner

*James Y. Kerr, II, Commissioner

North Carolina Utilities Commission
Office of the Chief Clerk
Mrs. Geneva S. Thigpen
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.

*Commissioner Lorinzo L. Joyner, appointed January 24, 2001.
*Commissioner James Y. Kerr, II, appointed July 1, 2001.

LETTER OF TRANSMITTAL

December 31, 2001

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, 2001, we hereby present for your consideration the report of the Commission's decisions for the 12-month period beginning January 1, 2001, and ending December 31, 2001.

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

Jo Anne Sanford, Chair

Judy Hunt, Commissioner

J. Richard Conder, Commissioner

Robert V. Owens, Jr., Commissioner

Sam J. Ervin, IV, Commissioner

Lorinzo L. Joyner, Commissioner

James Y. Kerr, II, Commissioner

Geneva S. Thigpen, Chief Clerk

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DOCKET NO. M-100, SUB 113

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of The Tax Reform Act of 1986	)))	ORDER CONCERNING GROSS UP FOR TAXES ON CONTRIBUTIONS IN AID OF CONSTRUCTION

BY THE COMMISSION: On January 11, 2001, the Internal Revenue Service (IRS) issued final regulations concerning the definition of contributions in aid of construction (CIAC). Such regulations are included in Appendix A, attached hereto. Under these final regulations, amounts paid for the cost of installing a connection or service line (including the cost of meters and piping) from the utility's main lines to the lines owned by the customer will remain taxable. This is consistent with the IRS's position prior to TRA86. The final regulations are effective for any money or other property received after January 11, 2001.

The Public Staff presented this matter at the Commission's Regular Staff Conference on March 5, 2001. The Public Staff stated that the taxes on customer connection fees will not have a significant impact on water and sewer utilities overall and that the taxability of CIAC is basically a timing difference. Since the CIAC is included in taxable income, the future tax benefits over the life of the property are equal to the taxes paid in the year the contribution was received. Therefore, the Public Staff recommended that the Commission not allow the use of the full gross up method except with prior approval in the rare case of an existing utility whose financial condition is such that paying the taxes itself would make the utility nonviable. Instead, the Public Staff recommended that the timing difference related to taxes paid by water and sewer utilities on taxable CIAC be included in accumulated deferred income taxes in rate base.

After careful review of this matter, the Commission concludes that water and sewer companies should not be allowed to use the full gross up method on taxable CIAC except with prior approval in the rare case of an existing utility whose financial condition is such that paying the taxes itself would make the utility nonviable.

IT IS, THEREFORE, ORDERED, as follows:

1. That water and sewer companies shall not use the full gross up method for money or other property received after January 11, 2001, to cover the cost of customer connections or service lines (including the cost of meters and piping) without prior Commission approval.

2. That prior approval will be granted only upon a showing by an existing utility that paying the taxes itself would make the utility nonviable, in which case the gross up collected and the taxes paid on the CIAC will be subject to being trued-up on an annual basis.

ISSUED BY ORDER OF THE COMMISSION.
This the _7th_ day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

pb030601.01

Contact the Chief Clerk's Office for Appendix A

GENERAL ORDERS - GENERAL

DOCKET NO. M-100, SUB 128

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Amendment to Certain Commission Rules) ORDER AMENDING RULES
to Reflect Current Law and Practice)

BY THE CHAIR: It has come to the attention of the Chair that certain Commission Rules, as set forth hereinafter, should be amended to reflect current law and practice before the Commission. In most cases, these Rules either refer to statutes or rules that have since been repealed or require an incorrect number of copies of filings. The Chair finds good cause to issue this Order amending Commission Rules as follows:

1. Commission Rule R1-5(g) is amended by deleting in its entirety the sentence beginning with the words "If the names..." Commission Rule R1-5(g) is further amended by rewriting Exception 1 to include a reference to gas utilities, to delete the references to "R8-42, or R8-43," and to change the number of copies required from 27 to 30. Finally, Commission Rule R1-5(g) is amended by rewriting Exception 3 to change the number of copies required from 10 to 3. Commission Rule R1-5(g), as amended herein, shall read as set forth in Appendix A attached hereto.

2. Commission Rule R1-11(b) is amended by changing the number of copies required from 22 to 3. Commission Rule R1-11(b), as amended herein, shall read as set forth in Appendix A attached hereto.

3. Commission Rule R1-12 is amended by changing the number of copies required from 9 to 3. The relevant portion of Commission Rule R1-12, as amended herein, shall read as set forth in Appendix A attached hereto.

4. Commission Rule R1-15 is amended by deleting the reference to "62-147" in the first paragraph. The first paragraph of Commission Rule R1-15, as amended herein, shall read as set forth in Appendix A attached hereto.

5. Commission Rule R1-24(g)(3) is amended by changing the number of copies required from 25 to 30. Commission Rule R1-24(g)(3), as amended herein, shall read as set forth in Appendix A attached hereto.

6. Commission Rule R2-8(a)(1) is amended by changing the number of copies required from 5 to 3. Commission Rule R2-8(a)(1), as amended herein, shall read as set forth in Appendix A attached hereto.

7. Commission Rule R2-8(b)(1) is amended by changing the number of copies required from 5 to 3. Commission Rule R2-8(b)(1), as amended herein, shall read as set forth in Appendix A attached hereto.

8. Commission Rule R9-8 is amended by deleting subsection (b) in its entirety and renumbering subsection (c) as (b) and subsection (d) as (c). Commission Rule R9-8, as amended herein, shall read as set forth in Appendix A attached hereto.

IT IS, THEREFORE, SO ORDERED

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg112901.04

Appendix A

1. Commission Rule R1-5(g), as amended herein:

(g) Copies Required. — The original plus twenty-five (25) copies of all pleadings shall be filed with the Commission (unless otherwise provided by the exceptions below), and shall include a certificate that a copy thereof has been mailed or delivered to each party of record in the cause or to counsel of record.

Exception 1. For filings by Class A & B electric, telephone, and natural gas utilities under Rules R1-7, R1-15, R1-17, and R1-24, an original plus thirty (30) copies shall be provided to the Commission.

Exception 2. For filings by Class A and B water and sewer utilities for rate increases or transfers, an original plus twenty four (24) copies shall be provided to the Commission. For all other filings by Class A and B water and sewer utilities, an original plus seven (7) copies shall be provided to the Commission.

For filings by Class C water and sewer utilities for rate increases or transfers, an original plus seven (7) shall be provided to the Commission. For all other filings by Class C water and sewer utilities, an original plus seven (7) copies shall be provided to the Commission.

Exception 3. For filings of applications by motor carriers under Rule R2-8(a) (1) and (b) (1), an original and three (3) copies shall be provided to the Commission.

NOTE: A photocopy which has been signed after copying shall be considered an original.

2. Commission Rule R1-11(b), as amended herein:

(b) Time for Filing. — Protests, as herein provided, must be filed with the Commission (original and three (3) copies) not less than ten (10) days prior to the date fixed for the hearing; provided, the notice of hearing may fix the time for filing protests, in which case such notice shall govern. All protests shall be signed and verified as provided in Rule R1-5, and shall certify that a copy thereof has been delivered or mailed to the applicant or to applicant's attorney, if any.

3. The relevant portion of Commission Rule R1-12, as amended herein:

No lease, sale, pledge, merger, or other transfer of motor carrier operating rights under any certificate issued by the Commission shall become effective except after application to and written approval by the Commission, which application shall be verified, filed with the Commission (original and three (3) copies), and shall set out, among other things, the following:

4. The first paragraph of Commission Rule R1-15, as amended herein:

Whenever there shall be filed with the Commission by any public utility or carrier, subject to its jurisdiction, any schedule stating new or changed rate or rates, as provided by General Statutes of North Carolina, §§ 62-134, 62-135, 62-138, 62-140, 62-142, or 62-146, the Commission may, upon protest or complaint of the Public Staff or of any interested party, or upon its own initiative, suspend such rates or charges pending an investigation of the lawfulness thereof, and to that end the following proceedings will be in order:

5. Commission Rule R1-24(g)(3), as amended herein:

(3) Copies Required. — An original plus thirty complete copies of the testimony of each expert witness, as required by this rule, shall be filed with the Commission for its use.

6. Commission Rule R2-8(a)(1), as amended herein:

(1) Application for authority to operate as a common carrier must be made on forms furnished by the Commission, and all the required exhibits must be attached to and made a part of the application. The original and three (3) complete copies of the application, including exhibits, must be filed with the Commission with a copy to the Public Staff. The original and the copies shall be fastened separately. A filing fee as set forth in G.S. 62-300 must accompany the application before it is considered as being filed.

7. Commission Rule R2-8(b)(1), as amended herein:

(1) Application for approval of sale, lease, or other transfer of operating authority shall be typewritten, shall be filed with the Commission with a copy to the Public Staff, by providing an original and three (3) copies and shall be accompanied by a filing fee as set forth in G.S. 62-300. Such applications may necessarily differ according to the nature of the transaction involved, but must include the following:

a. The names and addresses of all parties to the transaction.

b. A full and complete explanation of the nature of the transaction and its purpose.

8. Commission Rule R9-8, as amended herein:

Each regulated local exchange telephone company shall perform and provide service in accordance with the following uniform service objectives:

(a) *Service Objectives.* —

GENERAL ORDERS - GENERAL

DESCRIPTION	*OBJECTIVE*
Intraoffice completion rate	99% or more
Interoffice completion rate	98% or more
Direct distance dialing completion rate	95% or more
EAS transmission loss	95% or more between 2 and 10db
Intrastate toll transmission loss	95% or more between 3 and 12db
EAS trunk noise	95% or more 30 dbrnc or less
Intrastate toll trunk noise	95% or more 33 dbrnc or less
Operator "0" answertime	90% or more within 10 seconds or an *EAA in seconds
Directory assistance answertime	85% or more within 10 seconds or an *EAA in seconds
Business office answertime	90% or more within 20 seconds or an *EAA in seconds
Repair service answertime	90% or more within 20 seconds or an *EAA in seconds
Initial customer trouble reports (excludes subsequent reports)	4.75 or less per 100 access lines
Repeat reports	1.0 report or less per 100 access lines
Out-of-service troubles cleared within 24 hrs	95% or more
Regular service orders completed within 5 working days	90% or more
New service installation appointments not met for Company reasons	5% or less
New service held orders not completed within 30 days	0.1% or less of total access lines

*EAA = Equivalent Average Answertime

(b) This rule shall not preclude flexibility in considering future circumstances that may justify changes in or exceptions to these service objectives.

(c) Reporting Requirement - Each local exchange telephone company actually providing basic local residential and/or business exchange service to customers in North Carolina shall file an original and five (5) copies of a report each month with the Chief Clerk of the Commission detailing the results of its compliance with each of the uniform service objectives set forth in this rule. Each company shall report its performance result for each objective for its state service area as a whole and whenever possible, by exchange or district. This report shall be filed no later than twenty (20) days after the last day of the month covered by the report.

DOCKET NO. E-100, SUB 85

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Investigation of Certification Requirements) ORDER ADOPTING RULE
for New Generating Capacity in North Carolina)

BY THE COMMISSION: On November 17, 1999, the Commission initiated a proceeding in this docket by issuing an Order requesting comments on whether a generic rulemaking proceeding should be undertaken to address a number of concerns, including the filing requirements for a certificate of public convenience and necessity to construct new electric generating capacity intended to serve wholesale load on a merchant plant basis. Interested parties -- including utilities, consumer advocates and independent power producers (IPPs) -- intervened, and the Commission received written comments from them. The Commission subsequently issued an Order on April 26, 2000, holding the proceeding in abeyance "pending resolution of electric industry restructuring issues by the legislature or until some future event warrants further consideration of the issues raised..."

Such an event warranting further consideration in this docket occurred earlier this year. At the January 23, 2001 meeting of the Study Commission on the Future of Electric Service in North Carolina, the Study Commission redirected its focus to encouraging a robust and competitive wholesale market, and, consistent with that new focus, Senator Hoyle, as Co-Chair of the Study Commission, asked the Utilities Commission to review the requirements for certification of new electric generating capacity in North Carolina with a view toward streamlining the process. G.S. 62-110.1(a) requires that any electric generating facility to be directly or indirectly used for furnishing public utility service, whether constructed by a public utility or other person, must have a certificate of public convenience and necessity from the Utilities Commission before construction. There was no Commission Rule specifically addressing the filing requirements for merchant plants.

The Commission issued its Order Initiating Further Proceedings in this docket on February 7, 2001. By that Order, the Commission requested proposals and comments on what filing requirements are appropriate for certification of merchant plants, what new or revised Commission Rules should be adopted to implement such filing requirements, and how Commission procedures for certification of merchant plants may be streamlined. The Public Staff filed a proposed Rule R8-63 in this docket on March 14, 2001. Comments and reply comments have been filed by the following parties, all of whom have been allowed to intervene and participate herein: the Public Staff; the Attorney General (AG); Duke Power, a Division of Duke Energy Corporation (Duke); Carolina Power & Light Company (CP&L); Virginia Electric and Power Company, d/b/a Dominion North Carolina Power (Dominion); Piedmont Natural Gas Company, Inc. (Piedmont); the Carolina Utility Customers Association, Inc. (CUCA); the Carolina Industrial Groups for Fair Utility Rates (CIGFUR); Enron America (Enron); Dynegy Inc. (Dynegy); Calpine Eastern Corporation (Calpine); PG&E National Energy Group (PG&E); the Public Works Commission of the City of Fayetteville; and the Electric Power Supply Association.

The Commission has carefully weighed and considered all of the comments. On the basis thereof, the Commission will adopt a new Commission Rule R8-63 as reflected in the attached

Appendix A. The Commission will not try to summarize all of the comments, but will instead identify and discuss some of the major disagreements in the comments and some of the key provisions of the new Rule. These are discussed below:

Definition of Merchant Plant. The Public Staff's proposed Rule defined a merchant plant as an electric generating facility, other than a qualifying facility under PURPA, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility. There was little controversy as to this definition. CUCA suggested refining the definition to provide that a utility selling at retail may not own a merchant plant except through a separate subsidiary, but that suggestion raises issues that are pending in other Commission proceedings and are better handled there.

The Commission adopts the Public Staff's proposed definition as Rule R8-63(a)(2). This definition determines the scope and applicability of the new Rule adopted herein.

Prefiling of Information. At present, Commission Rule R8-61 requires all applicants proposing an electric generating facility with a capacity of 300 MW or more to prefile certain preliminary information at least 120 days before filing the certificate application itself. The Public Staff's proposed Rule would exempt merchant plants from the prefiling requirement of Rule R8-61. There was no outright opposition to the Public Staff's proposal. CP&L and Duke proposed eliminating the prefiling for utilities as well as merchant plants. They asked that Rule R8-61 be revised to allow the information that must now be prefiled 120 days before an application to be filed with the application instead, thus making the change applicable to all applications.

The Commission adopts the Public Staff's recommendation as Rule R8-63(a)(3). Eliminating the prefiling requirement of Rule R8-61 for merchant plants is a major step toward speeding up and streamlining the certification of merchant plants in North Carolina. The Commission will not adopt the recommendation of the utilities. If a utility is building a merchant plant, it will come under the new Rule adopted herein and will be exempt from prefiling. The question of whether a utility building a retail, rate-base generating plant should be exempt from the prefiling requirement of Rule R8-61 presents different issues and is not within the scope of this proceeding, which is focused on merchant plants. The utilities may pursue their argument in an appropriate docket if they wish.

Information Required as to the Applicant and the Proposed Facility. There is much disagreement as to exactly what information should be required in the application for a certificate for construction of a merchant plant. Among other items, the Public Staff's proposed Rule R8-63(b)(1)(A) and (B) would require that the applicant file financial information such as an annual report or a balance sheet and income statement; estimated construction costs; a proposed site layout of plant equipment and transmission interconnections; a list of other federal, state, and local permits and applications and their status; and a general description of transmission facilities to be used or the need for rights-of-way for new transmission.

The Public Staff argued that its proposed Rule would require only the fundamental information about the applicant and facility that the Commission needs in order to grant a certificate. The Public Staff agreed that merchant plants should be easier to certify than utility plants, but said that there are still significant issues and risks. The Public Staff argued that the information required by its proposed Rule is not extensive and will provide a minimum level of assurance. The AG agreed with the Public Staff. The AG supported streamlining but said that certain information is necessary for the Commission to fulfil its statutory duties. The AG argued that the Commission "will better serve the public by requiring sufficient information in applications for meaningful public consideration and comment."

Duke and some of the IPP intervenors -- such as Enron, Dynegy and PG&E -- opposed many of these proposed filing requirements. Duke would eliminate the requirement that an applicant provide its annual report or its balance sheet and income statement, saying that the Commission need not evaluate an applicant's creditworthiness. Duke would compress the information about the facility itself, eliminating such things as a site layout and a description of transmission facilities. Enron, Dynegy and PG&E generally commented that the above filing requirements are unnecessary, that the Commission need not micro-manage or exercise independent oversight as to these items because they will all be addressed by the developer through his due diligence and general plant development, and that the market will consider all these items and only viable plants will get built.

CUCA would go even further than other parties in eliminating information required in the certificate application. CUCA would only require a basic description of the applicant and facility, and even that could include "reasonable ranges" for size and in-service date to allow for modifications of plans. CUCA commented that information as to estimated construction costs should be limited to "confirmation that the costs...are 'consistent with projects of similar type and size.'"

The Commission takes its charge to streamline certification of merchant plants very seriously. However, the Commission has certain statutory duties with respect to the construction of electric generation. Statutes require that certain basic information be provided and that the Commission stay informed as to the state of electric generation in North Carolina. Moreover, by statute, the Commission's certification process serves a public notice function. On balance, the Commission decides to adopt the filing requirements proposed by the Public Staff, except as modified hereinafter. In doing so, the Commission wishes to stress several points. First, the Commission does not believe that the filing requirements adopted herein are onerous or that they will frustrate developers. Indeed, it would appear from the comments that developers will have to come up with all of this information anyway; nothing really new is being required. While this rulemaking process was pending, three applicants for merchant plant certificates, not wanting to wait, filed certificate applications based on the Public Staff's proposed Rule. The Commission takes this as an indication that these filing requirements are not overly burdensome and will not chill merchant plant development in the State. Further, the Commission does not intend to micro-manage merchant plant development. Finally, the Commission emphasizes that any applicant may ask for a waiver of any filing requirement if reason exists and good cause for a waiver is shown. The Commission believes that this decision reflects an appropriate balance between streamlining the certification process and meeting statutory obligations and the public interest.

Information on Market Power. The Public Staff's proposed Rule R8-63(b)(1)(B)(vii) would require that an application for a merchant plant certificate include information about other generating facilities and/or sites intended for such facilities in the region that the applicant or an affiliate owns and/or controls. The Public Staff commented that such information will help the Commission "obtain a comprehensive view of the developing wholesale market." The AG commented that it is necessary to consider market power information such as this in a certificate proceeding in order to encourage wholesale competition. CIGFUR also wanted information about market power in the application and stated that the Commission should deny certification if market power concerns are not resolved.

Duke and CP&L opposed this filing requirement. They argued that the requirement is vague and irrelevant and would needlessly complicate the certificate process. Calpine would either eliminate or at least clarify the requirement. Calpine found some of the proposed language unclear, and the Public Staff responded with some clarifications in its reply comments. PG&E would eliminate information on affiliated facilities or sites, arguing that anti-trust and market abuses are the purview of other fora. CUCA wanted market power addressed in an appropriate forum but said that market power concerns should not impede the streamlining of certification in this docket.

The Commission concludes that some information bearing on market power is appropriate and should be required in merchant plant certificate applications. The Commission will require information on other facilities of the applicant or one of the applicant's affiliates. For these purposes, the region is defined as the Southeastern Electric Reliability Council region. Information as to certificates that have been granted for other plants not yet constructed, though not included in the Public Staff's proposed Rule, will also be required. The Commission is less convinced as to the importance of information on other sites intended for such facilities in the region, and such information will not be required at this time. It should be noted that the Commission has recently undertaken a survey in a separate docket of how many possible sites are suitable for merchant plant development in the State.

Information on Natural Gas Capacity and Supply. The Public Staff's proposed Rule R8-63(b)(1)(B)(iv) would require that certificate applications for gas-fired merchant plants include information about the proximity of existing natural gas facilities, any new dedicated natural gas facilities to be constructed, and any contracts or tariffs for interstate pipeline capacity. The Public Staff commented that North Carolina has limited natural gas interstate pipeline capacity and that it would be unwise to certify a plant if the plant could only operate part-time due to capacity limits.

CUCA commented that the Public Staff is over-regulating, that the market will not allow a plant to be built if its gas supply is inadequate, and that requiring too much information will discourage new electric generation. This filing requirement was also opposed by parties such as Enron, Dynegy, PG&E, and Calpine. They argued that requiring information about arrangements for pipeline capacity is excessive, that the Commission should not weigh the commercial viability of each project's fuel strategy, and that a plant will simply not be built if it doesn't have capacity.

Piedmont intervened and commented on the arrangements of gas-fired merchant plants for pipeline capacity and gas supply. First, Piedmont agreed that an application should provide details as to proposed natural gas capacity and supply and that the public interest requires examination of such arrangements since available capacity is already subscribed and there is already high demand for existing gas supply. Second, Piedmont commented that gas-fired merchant plants can cause swings in operational pressure and flow of pipelines, which may affect service to the North Carolina LDCs. Piedmont argued that the Commission should require applicants to show that they will not adversely impact existing natural gas service in the State. Third, Piedmont argued that the Commission should, as part of the certification process, require that applicants for merchant plant certificates get service from the local LDC, rather than bypass the LDC and connect directly with an interstate pipeline.

PG&E objected to Piedmont's proposals as "bad business and bad law." Calpine also objected, arguing that the impact of a new generating facility on existing gas service is not an appropriate issue for a certificate proceeding and that requiring a new facility to get service from the local LDC may be in conflict with federal law. CUCA stated that bypass is legal in North Carolina and that Piedmont is only out to "protect its monopoly..."

For the reasons previously cited, the Commission adopts the Public Staff's recommendation. Again, the Commission does not mean to micro-manage merchant plant development but feels that this is appropriate information to keep the Commission informed as to the development of electric generation in the State. The Commission shares Piedmont's concerns about the operational and economic impact of gas-fired merchant plants on the gas pipeline system and on other customers. However, the Commission feels that such issues can and should be addressed in individual certificate proceedings. Although the Commission has expressed concerns as to bypass of local LDCs by new merchant plants, the Commission believes that this is an issue best addressed in certificate cases where individual fact situations are presented.

Showing of Need. The issue of what must be shown to establish the need for a merchant plant is one of the main concerns that prompted this proceeding to streamline certification procedures. In its 1992 decision regarding Empire Power Company in Docket No. SP-91, the Commission dismissed a certificate application for a merchant plant, stating that as a minimum filing requirement "an IPP proposing to sell its electricity to a North Carolina utility must first obtain and allege as part of its certificate application either a contract or a written commitment from the utility." The Commission addressed this old requirement in the order initiating the present proceedings. In the February 7, 2001 Order in this docket, the Commission recognized that the environment in which the Empire decision was made has changed in many crucial ways, and the Commission commented that "Empire is not a decision whose reasoning the Commission would follow per se today because the reasoning behind it does not reflect the situation in the industry today." The Order left open the issue of what new requirement would be adopted.

In the comments that have been filed herein, no party advocated that the Empire requirement be retained. The Public Staff's proposed Rule R8-63(b)(1) would require that applications for certificates for merchant plants include a showing of need as follows: "A description of the need for the facility in the state and/or region, with supporting documentation. This documentation shall include, as appropriate, either (i) contracts or preliminary agreements for the output of the facility, or (ii) information demonstrating that there is a need for the applicant's power in its intended market." Public Staff stated that this would be "an adequate but much less specific showing of need."

Duke would simplify the statement of need even more by eliminating the reference to contracts or preliminary agreements. Duke said that that sounds too much like the old Empire requirement. Duke would have an applicant simply show that there is a need for the generation in its intended market. Dominion commented that no showing of need should be required at all because retail customers do not need protection from over-expansion of generation. If any showing of need is retained, Dominion stated that it should be quite general. CP&L stated that an appropriate standard for showing need would be whether reserve margins will fall below some threshold level within the region.

CUCA and Dynegy both supported a general statement of need in the state and/or region. Enron would keep the first sentence proposed by the Public Staff but delete the second as too restrictive. Calpine suggested adopting a presumption that need could be shown by forecasts or declining reserve margins. PG&E urged the Commission to find a presumption of need in recent federal law encouraging wholesale competition or to adopt a very low threshold, such as general growth in the region. PG&E wanted to limit intervention on the issue of need to the Public Staff and AG, but CP&L opposed the idea of limiting intervention.

It is the Commission's intent to facilitate, and not to frustrate, merchant plant development. Given the present statutory framework, the Commission is not in a position to abandon any showing of need or to create a presumption of need. However, the Commission believes that a flexible standard for the showing of need is appropriate. The Commission adopts the first sentence of the Public Staff's recommendation but will not adopt the second sentence. The Commission agrees with Duke that the reference to "contracts or preliminary agreements" in the second sentence brings to mind the old Empire requirement and might raise doubts as to whether the Commission has truly abandoned that requirement. The Commission has abandoned the contract requirement of Empire as inappropriate in today's environment.

Utility-Affiliate Pricing. In connection with recent mergers, Duke, CP&L, and Dominion each agreed to codes of conduct which address utility-affiliate pricing. The Commission approved these codes of conduct and ordered the utilities to comply with them. In general, these codes of conduct require that, for inter-company exchanges, an affiliate must pay the utility the higher of fully allocated cost or market price and the utility must pay its affiliate the lower of fully allocated cost or market. In this proceeding, Duke argued that the pricing rules in these codes of conduct effectively preclude utility affiliates from developing merchant plants in North Carolina and that the Commission should use the present rulemaking proceeding to change the rules. Duke would add a provision to this new Rule to the effect that utilities may purchase from merchant plants owned by their affiliates at market rates approved by the Federal Energy Regulatory Commission and that such rates will be deemed reasonable for retail ratemaking purposes.

The Public Staff, AG, and CIGFUR all pointed out that such a provision would be contrary to the codes of conduct that Duke and other utilities agreed to in recent merger proceedings and that the provision raises important issues that are beyond the scope of this proceeding. The Commission agrees that Duke's proposal raises issues beyond the scope of this proceeding and should be considered in other dockets.

Procedure upon Receipt of Application. The Commission wants to avoid delays in processing applications for merchant plant certificates. The Public Staff's proposed Rule R8-63(d) would allow 10 days after receipt of an application for the Public Staff to examine it and give notice whether it is complete or is deficient in some way. The Commission would require any missing information to be provided and then issue a procedural order scheduling a hearing once everything is filed. The Public Staff said that this procedure would allow deficiencies to be handled promptly and would allow a procedural order to be issued without waiting for the matter to be placed on a Commission agenda. Duke and CP&L would allow "any party in interest" to point out deficiencies in an application.

The Commission generally adopts the Public Staff language. Allowing a procedural order to be issued without the matter being placed on a Monday morning Commission agenda should expedite handling. The Commission will allow parties other than the Public Staff to point out deficiencies in an application, consistent with the procedure that Rule R1-17(f)(1) now provides for general rate case applications. However, in recognition of its unique responsibilities, the Commission will require that the Public Staff file notice within 10 days of every application filing stating its opinion as to whether the application is complete or deficient and, if deficient, in what way it is deficient. This filing by the Public Staff will prompt the Commission's procedural order.

Scheduling a Hearing. The Public Staff's proposed Rule R8-63(b)(3) would require that supporting testimony be filed with the application and proposed Rule R8-63(d) would provide that the Commission issue an order "setting the matter for hearing" once a complete application is filed. The Public Staff stated that a public hearing is required by G.S. 62-110.1(e) and that it would save time to require prefiled testimony along with the application and to schedule a hearing on every application right at the outset.

CUCA, citing G.S. 62-82(a), argued that the Commission should announce a presumption that certificates will be issued without a hearing and that a complaint demonstrating good cause should be required before a hearing will be held. CUCA would therefore eliminate the pre-filing of testimony. CP&L agreed that there should be a presumption that no hearing is required unless good cause is shown.

Once again, the Commission's interest is in expediting the processing of merchant plant applications. There is a conflict between G.S. 62-110.1(e) and G.S. 62-82(a). Both deal with applications for a certificate for an electric generating facility but G.S. 62-110.1(e) states, "The Commission shall hold a hearing on each such application..." while G.S. 62-82(a) only requires that a hearing be held "upon complaint..." G.S. 62-110.1(e) is the more recent enactment, having been added in 1975. The Public Staff, citing G.S. 62-110.1(e), would schedule a hearing in every case right from the start. They explain, "If not set at the outset, there is a clear potential for delay if a hearing is later determined to be appropriate." Both Duke and Enron filed proposed rules that agree with the Public Staff on this point. The Commission agrees that scheduling a hearing on every application up front will tend to streamline procedures for certification of merchant plants.

Revocation of the Certificate. The Public Staff's proposed Rule R8-63(e) would provide for revocation of a certificate, after notice and opportunity for correction, under certain circumstances, e.g., if other permits are not obtained, if reports are not filed or fees not paid, or if material inaccurate information has been filed. Dynegy expressed concerns about the revocation provisions, arguing that any revocation should be discretionary, that any revocation should be triggered only by significant noncompliance or malfeasance, and that due process guarantees of notice and hearing should be observed. In its reply comments, the Public Staff revised its proposal in response to such concerns. The only other comment on this issue was by CUCA, which would allow for revocation only pursuant to G.S. 62-80 and the conditions set forth in the order granting the certificate.

The Commission adopts the revised language of the Public Staff, which makes very specific and strict provisions for revocation.

Transfer of the Certificate. The Public Staff's proposed Rule R8-63(e) would require the certificate holder to notify the Commission of any plans to sell, transfer, or assign the certificate and facility. PG&E commented that it should be clear that notice of transfers would be for information only and that the Commission has no authority to approve or deny a sale or assignment of a certificate. The Public Staff commented that the Commission has authority to impose appropriate conditions on certificates, including a condition that any subsequent transfer be subject to Commission approval. The Public Staff feels that the Commission needs some continuing authority as to how the merchant plant is being used after the certificate is issued, both for planning purposes and for preventing market power abuses. The Public Staff did not propose that approval of transfers be required by this Rule, but the Public Staff apparently intends to propose such a condition as individual certificate applications are decided.

The Commission adopts the requirement that a certificate holder give notice of any plans to sell, transfer or assign the certificate and facility. This requirement of notice is not as controversial as the further issue raised by the Public Staff -- whether the Commission should assert authority to approve transfers. That issue is an appropriate matter for individual certificate cases and will be considered if and when it arises in such dockets.

Other Certificate Conditions. CUCA commented that a merchant plant certificate should be subject to a condition that the applicant receive and maintain other regulatory approvals and a condition that the applicant abstain from trying to exercise eminent domain power. The Public Staff agreed to CUCA's suggestion for a condition as to eminent domain. The AG suggested that the matter of putting conditions in certificates be considered later so as not to hold up this proceeding. As indicated in the previous discussion, the Commission agrees with the AG and will decide what conditions to attach to certificates as individual certificate cases come to decision.

In conclusion, the Commission has carefully considered all of the proposed Rules and comments herein, and the Commission hereby adopts new Rule R8-63, attached hereto as Appendix A. The Commission believes that this Rule streamlines the certification process for merchant plants while providing the Commission with the information it needs under current law. This new Rule eliminates the 120-day prefiling requirement, clarifies application filing requirements, replaces the old contract requirement with a new liberal standard for showing need, and lays out procedures to bring applications to decision promptly. The development of a competitive wholesale market is in an early stage in this State. There is still a role for the Commission to ensure an adequate and reliable supply of electricity. At this point, incremental steps are appropriate. However, the Commission will monitor practice under the new Rule, and the Commission stands ready to consider further ideas for maximizing the benefits of the emerging market while reducing risks of the transition to a new industry structure.

IT IS, THEREFORE, ORDERED that the Commission adopts new Commission Rule R8-63, attached hereto as Appendix A.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of May, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rg052101.01

Appendix A

Rule R8-63. Application for certificate of public convenience and necessity for merchant plant; progress reports.

(a) Scope of Rule.

(1) This rule applies to an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1(a) by any person seeking to construct a merchant plant in North Carolina.

(2) For purposes of this rule, the term "merchant plant" means an electric generating facility, other than one that qualifies for and seeks the benefits of 16 U.S.C.A. 824a-3 or G.S. 62-156, the output of which will be sold exclusively at wholesale and the construction cost of which does not qualify for inclusion in, and would not be considered in a future determination of, the rate base of a public utility pursuant to G.S. 62-133.

(3) Persons filing under this rule are not subject to the requirements of Rule R1-37 or Rule R8-61.

(b) Application.

(1) The application shall contain all of the information hereinafter required, with each item labeled as set out below. Any additional information may be included at the end of the application.

(A) The Applicant:

(i) The full and correct name, business address, and business telephone number of the applicant;

(ii) A description of the applicant, including the identities of its principal participant(s) and officers, and the name and business address of a person authorized to act as corporate agent or to whom correspondence should be directed; and

(iii) A copy of the applicant's most recent annual report to stockholders, which may be attached as an exhibit, or, if the applicant is not publicly traded, its most recent balance sheet and income statement. If the applicant is a newly formed entity with little history, this information should be provided for its parent company, equity partner, and/or the other participant(s) in the project.

(B) The Facility:

(i) The nature of the proposed generating facility, including its type, fuel, size, and expected service life; the anticipated beginning date for construction; the expected commercial operation date; and estimated construction costs;

(ii) A detailed description of the location of the generating facility, including a map with the location marked;

(iii) The proposed site layout of all major equipment and a diagram showing the generator, plant distribution system, startup equipment, and provisions for transmission interconnection;

(iv) In the case of natural gas-fired facilities, a map showing the proximity of the facility to existing natural gas facilities; a description of dedicated facilities to be constructed to serve the facility; and any filed agreements, service contracts, or tariffs for interstate pipeline capacity;

(v) A list of all needed federal, state, and local approvals related to the facility and site, identified by title and the nature of the needed approval; a copy of such approvals or a report of their status; and a copy of any application related to eligible facility and/or exempt wholesale generator status pursuant to Section 32 of the Public Utility Holding Company Act of 1935 (PUHCA), as amended by the Energy Policy Act of 1992, including attachments and subsequent amendments, if any;

(vi) A general description of the transmission facilities to which the facility will have access or the necessity of acquiring rights-of-way for new facilities; and

(vii) Information about generating facilities in the Southeastern Electric Reliability Council region which the applicant or an affiliate has any ownership interest in and/or the ability to control through leases, contracts, options, and/or other arrangements and information about certificates that have been granted for any such facilities not yet constructed.

(C) Statement of Need: A description of the need for the facility in the state and/or region, with supporting documentation.

(2) The application shall be signed and verified by the applicant or by an individual duly authorized to act on behalf of the applicant.

(3) The application shall be accompanied by prefiled direct testimony incorporating and supporting the application.

(4) The Chief Clerk will deliver ten (10) copies of the application to the Clearinghouse Coordinator in the Department of Administration for distribution to State agencies having an interest in the proposed generating facility.

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

(d) Procedure upon Receipt of Application. No later than ten (10) business days after the application is filed with the Commission, the Public Staff shall, and any other party in interest may, file with the Commission and serve upon the applicant a notice regarding whether the application is complete and identifying any deficiencies. If the Commission determines that the application is not complete, the applicant will be required to file the missing information. Upon receipt of all required information, the Commission will promptly issue a procedural order setting the matter for hearing, requiring public notice, and dealing with other procedural matters.

(e) The Certificate.

(1) The certificate shall specify the name and address of the certificate holder; the type, size, and location of the facility; and the conditions, if any, upon which the certificate is granted.

(2) The certificate shall be subject to revocation if (a) any of the federal, state, or local licenses or permits required for construction and operation of the generating facility is not obtained or, having been obtained, is revoked pursuant to a final, non-appealable order; (b) required reports or fees are not filed with or paid to the Commission; and/or (c) the Commission concludes that the certificate holder filed with the Commission information of a material nature that was inaccurate and/or misleading at the time it was filed; provided that, prior to revocation pursuant to any of the foregoing provisions, the certificate holder shall be given thirty (30) days' written notice and opportunity to cure.

(3) The certificate must be renewed if the applicant does not begin construction within two years after the date of the Commission order granting the certificate.

(4) A certificate holder must notify the Commission in writing of any plans to sell, transfer, or assign the certificate and the generating facility.

(f) Reporting. All applicants must submit annual progress reports and any revisions in cost estimates, as required by G.S. 62-110.1(f) until construction is completed.

DOCKET NO. E-100, SUB 85

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Investigation of Certification Requirements) ORDER AMENDING
for New Generating Capacity in North Carolina) RULE R8-63

BY THE COMMISSION: On May 21, 2001, the Commission issued its Order Adopting Rule in this docket, adopting new Commission Rule R8-63 which deals with certification of merchant plants. The Order discussed certain issues raised by Piedmont Natural Gas Company, Inc. (Piedmont), but left the issues for decision in future certificate proceedings.

On June 22, 2001, Piedmont filed a letter asking that Rule R8-63 be amended to ensure that notice of merchant plant certificate applications are served on natural gas local distribution companies (LDCs). Piedmont proposed that a new subsection (g) be added to the Rule as follows:

> (g) Contemporaneous with the filing thereof with the Commission, a copy of the application, including all supporting schedules, attachments and testimony, shall be served on (i) the natural gas local distribution company providing service or certificated to provide service at the location of the proposed generating facility; and (ii) any other North Carolina natural gas local distribution company receiving service from the interstate pipeline through which natural gas serving the proposed generating facility will be transported.

On June 27, 2001, the Commission issued an Order Requesting Comments on this proposed amendment. Comments were filed by the Public Staff; Carolina Utility Customers Association, Inc. (CUCA); Dynegy, Inc.; and Duke Power.

The Public Staff agreed that an applicant proposing a merchant plant that will use natural gas should serve a copy of the full application on the LDC providing service at the proposed site; however, the Public Staff suggested that only notice, rather than a copy of the application, be given to the other North Carolina LDCs. The Public Staff proposed an amendment to read as follows:

> (g) Information to Local Distribution Companies. Contemporaneous with the filing thereof with the Commission, a copy of any application for a generating facility that will use natural gas, including all supporting schedules, attachments and testimony, shall be served on the natural gas local distribution company providing service or certificated to provide service at the location of the proposed facility. A notice describing the type, size and location of the proposed gas-fired facility shall be served on any other North Carolina natural gas local distribution company receiving service from the interstate pipeline through which natural gas serving the proposed generating facility will be transported.

Piedmont filed a letter on July 19, 2001, agreeing with the Public Staff's proposal.

CUCA argued that Piedmont's proposed amendment is inconsistent with the goal of streamlining certification of new merchant plants. CUCA argued that LDCs should bear the burden of monitoring and intervening in merchant plant proceedings "in the same manner that CUCA and other potential intervenors are burdened."

Duke made similar comments. Duke argued that the additional filings proposed by Piedmont would be "time consuming, costly and overly burdensome."

Dynegy stated that it is easy to monitor new merchant plant filings with the Commission and that requiring service of the application to the LDCs is unnecessary and inconsistent with streamlining. If the Commission wishes to provide some form of notice, Dynegy suggested the following:

> (b)(5) Contemporaneous with the filing of the application with the Commission, all applicants must provide written notice of the filing to the natural gas local distribution company providing service or certificated to provide service at the location of the proposed generation facility.

The Commission has considered all of the comments herein. The Commission agrees with Piedmont that an LDC is in a special position as to a merchant plant that will be built in its franchised territory and fueled by natural gas. The Commission will require that notice of such applications be provided to the LDC that is franchised to serve the proposed site. Otherwise, however, the Commission believes that LDCs should be treated the same as other persons who have some interest in Commission proceedings and may, or may not, decide to intervene in particular dockets. Such other persons are responsible for monitoring filings at the Commission; applicants are not required to give them notice. Monitoring merchant plant applications filed with the Commission is easy since all such filings are now made in EMP-designated dockets. Therefore, the Commission finds good cause to amend Rule R8-63 by adding a new subdivision as follows:

> (b)(5) Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution company providing service or franchised to provide service at the location of the proposed generating facility.

IT IS, THEREFORE, ORDERED that Commission Rule R8-63 should be, and hereby is, amended by adding a new subdivision to read as follows:

(b)(5) Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution company providing service or franchised to provide service at the location of the proposed generating facility.

ISSUED BY ORDER OF THE COMMISSION.
This the 27th day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg072601.03

DOCKET NO. E-100, SUB 85

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation of Certification Requirements	)	ORDER AMENDING
for New Generating Capacity in North Carolina	)	RULE R8-63

BY THE COMMISSION: On June 27, 2001, the Commission issued an order amending Commission Rule R8-63, by adding a new subsection (b)(5) requiring that applicants for a certificate for a merchant plant "must provide written notice of the filing to the natural gas local distribution company providing service or franchised to provide service at the location of the proposed generating facility."

On October 5, 2001, the North Carolina Municipal Gas Association or Gas Cities, eight municipalities that operate natural gas distribution systems, filed a petition to intervene and a letter asking that the Commission include them in the notice requirement of Rule R8-63(b)(5). The Gas Cities argue that if an applicant for a merchant plant certificate plans to build within an area served by one of them, the municipality has the same interest as a local distribution company.

The letter was served on all parties to this docket, but no responses have been received. The Commission finds good cause to allow the petition to intervene and the request to amend Rule R8-63(b)(5).

IT IS, THEREFORE, ORDERED that Commission Rule R8-63(b)(5) should be, and hereby is, amended by adding "or municipal gas city" to read as follows:

(b)(5) Contemporaneous with the filing of the application with the Commission, all applicants proposing a generating facility that will use natural gas must provide written notice of the filing to the natural gas local distribution company or municipal gas system providing service or franchised to provide service at the location of the proposed generating facility.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg110501.04

DOCKET NO. E-100, SUB 87

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Biennial Determination of Avoided Cost	)	ORDER ESTABLISHING STANDARD
Rates for Electric Utility Purchases	)	RATES AND CONTRACT TERMS FOR
from Qualifying Facilities - 2000	)	QUALIFYING FACILITIES

BY THE COMMISSION: These are the current biennial proceedings held by the North Carolina Utilities Commission pursuant to the provisions of Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Energy Regulatory Commission (FERC) regulations implementing those provisions which delegated responsibilities in that regard to this Commission. These proceedings are also held pursuant to the responsibilities delegated to this Commission pursuant to N.C.G.S. 62-156(b) to establish rates for small power producers as that term is defined in N.C.G.S. 62-3(27a).

Section 210 of PURPA and the regulations promulgated pursuant thereto by the FERC prescribe the responsibilities of the FERC and of State regulatory authorities, such as this Commission, relating to the development of cogeneration and small power production. Section 210 of PURPA requires the FERC to prescribe such rules as it determines necessary to encourage cogeneration and small power production, including rules requiring electric utilities to purchase electric power from, and to sell electric power to, cogeneration and small power production facilities. Under Section 210 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power can become "qualifying facilities," (hereinafter often referred to as QFs) and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

GENERAL ORDERS - ELECTRICITY

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying facility status under Section 210 of PURPA. For such purchases, electric utilities are required to pay rates which are just and reasonable to the ratepayers of the utility, which are in the public interest, and which do not discriminate against cogenerators or small power producers. The FERC regulations require that the rates electric utilities pay to purchase electric energy and capacity from qualifying cogenerators and small power producers shall reflect the cost that the purchasing utility can avoid as a result of obtaining energy and capacity from these sources, rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. With respect to the electric utilities, the implementation of these rules was delegated to the State regulatory authorities. Implementation may be accomplished by the issuance of regulations on a case-by-case basis or by any other means reasonably designed to give effect to the FERC's rules.

The Commission at the outset determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. The instant proceeding is the latest such proceeding to be held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined separate avoided cost rates to be paid by four electric utilities to the QFs which are interconnected with them. The Commission has also reviewed and approved other related matters involving the relationship between the electric utilities and the QFs interconnected with them, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also involves the carrying out of the Commission's duties under the mandate of G.S. 62-156, which was enacted by the General Assembly in 1979. G.S. 62-156 provides that "no later than March 1, 1981, and at least every two years thereafter" this Commission shall determine the rates to be paid by electric utilities for power purchased from small power producers according to certain standards prescribed therein. Such standards generally approximate those which are prescribed in the FERC regulations regarding factors to be considered in the determination of avoided cost rates. The definition of the term small power producer is more restrictive in G.S. 62-156 than the PURPA definition of that term, in that it includes only hydroelectric facilities of 80 megawatts (MW) or less, thus excluding users of other types of renewable resources.

On July 6, 2000, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing. That Order made Carolina Power & Light Company (CP&L), Duke Power, a division of Duke Energy Corp. (Duke), Virginia Electric and Power Company d/b/a Dominion North Carolina Power (NC Power), and Western Carolina University (WCU) parties to the proceeding to establish the avoided cost rates each is to pay for power purchased from QFs and small power producers pursuant to Section 210 of PURPA and the FERC regulations associated therewith, and G.S. 62-156. The Order also required each electric utility to file proposed rates and proposed standard form contracts. The Order stated that the Commission would attempt to resolve all issues arising in this docket based on a record developed through public witness testimony, written statements, exhibits and avoided cost schedules verified by persons who would otherwise be qualified to present expert testimony in a formal hearing, and written comments on the statements, exhibits and schedules, rather than a full evidentiary hearing. CP&L, Duke, NC Power and WCU were required to file their statements and exhibits by November 3, 2000. Other persons desiring to become parties were allowed to intervene and to file their statements and exhibits by January 5, 2001. All parties were allowed to file reply comments and proposed orders. The Commission scheduled a public hearing for January 30, 2001, solely for the purpose of taking nonexpert public witness testimony.

On November 3, 2000, CP&L, Duke and NC Power filed their initial statements and exhibits. On November 7, 2000, WCU filed its initial statement and exhibits.

On November 7, 2000, Carolina Industrial Groups for Fair Utilities Rates I & II (CIGFUR) filed a Petition to Intervene. By Order dated January 29, 2001, the Petition to Intervene was granted.

On February 2, 2001, Southeastern Hydro-Power, Inc. filed a Petition to Intervene.

On January 5, 2001, Southeastern Hydro-Power filed Comments and the Public Staff filed its Initial Statement. On January 9, 2001, Lockville Hydropower filed its Statement.

On January 30, 2001, the Commission held a public hearing solely for the purpose of taking non-expert public witness testimony. Mr. Leroy Townsend of Lockville Hydropower testified at the January 30th public hearing.

On February 2, 2001, Duke, CP&L and NC Power filed Reply Comments.

On February 20, 2001, Lockville Hydropower filed a letter with the Commission under seal of confidentiality addressing its testimony on January 30, 2001.

Based on the foregoing, all of the parties' comments and exhibits, the public witness testimony at the hearing and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. CP&L should offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. CP&L shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable

for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

3. NC Power should offer long-term levelized capacity payments and energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. NC Power shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity. NC Power shall offer long-term levelized energy payments as an additional option for small qualifying facilities rated at 100 kW or less capacity.

4. CP&L, Duke and NC Power should offer qualifying facilities not eligible for the standard long-term levelized rates the options of contracts to sell energy only at the variable rates established by the Commission or, as appropriate, contracts and rates derived by free and open negotiations with the utility or participation in the utility's competitive bidding process for obtaining additional capacity. The Commission expects all utilities to negotiate in good faith with qualifying facilities. The Commission will set no specific guidelines in this proceeding for such negotiations.

5. Duke and CP&L use the peaker method to develop avoided capacity costs. NC Power uses the differential revenue requirement (DRR) methodology. Both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and are reasonable for use in this proceeding.

6. A performance adjustment factor of 2.0 should be utilized by both CP&L and Duke for their respective avoided cost calculations for hydroelectric facilities with no storage capability and no other type of generation.

7. A performance adjustment factor of 1.2 should be utilized by both CP&L and Duke for their respective avoided cost calculations for all QFs in this proceeding <u>except</u> hydroelectric facilities with no storage capability and no other type of generation.

8. CP&L should be required to include the capital costs of land and transmission facilities in its calculation of capacity credits.

9. NC Power should be required to include the capital costs of land in its calculations of capacity credits for purposes of this proceeding.

10. The standard contract requirement that a utility have exclusive rights to purchase power from a QF when its initial contract with that QF comes up for renewal should continue to be approved.

11. Southeastern's proposal that standard contract language be required specifying that all environmental and resulting financial rights will remain with the QF should be denied without prejudice to further discussion of the issue in future proceedings.

12. The rate schedules and standard contract terms and conditions proposed by CP&L, Duke, and NC Power in this proceeding should be approved subject to the modifications discussed herein.

13. WCU's proposed Small Power Production Supplier Reimbursement Formula is reasonable and appropriate. WCU should not be required to offer any long-term levelized rate options to qualifying facilities.

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

Whether the Commission should require the electric utilities to offer long-term levelized rates to QFs as standard rate options has been an issue in prior avoided cost proceedings, and it is an issue in this proceeding as well. Long-term levelized rates are permitted, but not required, by the regulations implementing Section 210 of PURPA. Long-term contracts are "encouraged in order to enhance the economic feasibility of small power production facilities" by G.S. 62-156(b)(1).

Prior to the 1984 avoided cost proceeding in Docket No. E-100, Sub 41A, CP&L and Duke were required to offer standard long-term levelized rate options to all QFs, and NC Power was required to offer such options only to small power producers as defined in G.S. 62-3(27a), i.e., hydroelectric facilities of 80 megawatts or less capacity. The standard long-term levelized rate options were required by this Commission in order to encourage the development of cogeneration and small power production facilities. However, in the 1984 proceedings both the Public Staff and the utilities raised concerns about these options, and the Commission undertook a reexamination of the issue. The Commission sought a balance between the policy of encouraging QF development, especially the development of small power producers under G.S. 62-156, and the risks posed by defaults and by the uncertainty of the long-term projections on which long-term rates are based. The Commission resolved these concerns by requiring CP&L, Duke and NC Power to offer long-term levelized rates for 5, 10, and 15-year periods as standard options to hydro QFs of 80 megawatts or less capacity, i.e., small power producers under G.S. 62-3(27a), and to non-hydro QFs contracting to sell five megawatts or less capacity. Non-hydro QFs contracting to sell capacities of more than five megawatts were given the options of contracts at the variable rates set by the Commission or contracts negotiated with the utility. The Commission continued this basic framework of long-term levelized rate options through several biennial proceedings with two changes: (1) starting with the 1988 proceeding in Docket No. E-100, Sub 57, NC Power was allowed to change from a long-term levelized energy payment to energy payments based on a long-term levelized generation mix with adjustable fuel prices (NC Power was required to offer a long-term levelized energy payment as an additional option for small QFs of 100 kW or less) and (2) as utilities began to pursue competitive bidding (first NC Power in Docket E-100, Sub 57 in 1988, then Duke in Docket No E-100, Sub 64 in 1994, finally CP&L in Docket No. E-100, Sub 74 on April 25, 1996), non-hydro QFs desiring to sell capacities of five megawatts or more were required to participate in the bidding (rather than negotiating a contract with the utility).

In previous biennial proceedings, CP&L reached a compromise agreement with the Public Staff, pursuant to which CP&L would offer 5, 10, and 15-year levelized rates to hydro QFs of 5 MW or less capacity and to QFs of 5 MW or less capacity fueled by trash or methane from landfills or hog waste. They also agreed that CP&L would offer 5-year levelized rates to all other QFs with 3 MW or less capacity. The Commission adopted the CP&L/Public Staff compromise in those biennial proceedings and made it applicable to Duke and NC Power also.

In the current biennial proceeding in Docket No. E-100, Sub 87, CP&L, Duke and NC Power propose eliminating the 10-year and 15-year levelized rate options from their standard rates available to QFs. CP&L cites the impossibility of producing reliable forecasts of costs ten and fifteen years into the future, and the existence of a viable wholesale market for QF power that removes the necessity for IOUs to be buyers of last resort for the QFs. Duke and NC Power's arguments are similar to those of CP&L.

The Public Staff recommended that its compromise agreement with CP&L in previous proceedings should again be applied to Duke and NC Power as well as to CP&L. It cited the Commission's Order in previous biennial proceedings that described a balance between the need to encourage QFs, particularly hydro and trash or methane fueled facilities, against the need to reduce the risk of overpayment and stranded costs.

Southeastern Hydro-Power and witness Townsend of Lockville Hydropower argued that eliminating the 15-year levelized rates would yield more hardship on small hydro QFs, and contended that bank financing would be harder to obtain. Southeastern also proposed that 15-year levelized rates be applicable from the day the new plant goes into service rather than the day the contract is signed, in order to allow up to two years to construct the new plant without losing any time on the 15-year rate. Southeastern further proposed that long-term rates offer a fixed option as well as a levelized option. (Such "fixed" option seems to be the actual forecasted level of rates in each future year, as contrasted to the single or "levelized" rate level applicable in all of the forecasted years.)

In re-examining the availability of long-term levelized rate options in this docket, the Commission must balance concerns similar to those considered in previous proceedings—encouragement of QFs on the one hand and the risks of overpayments and stranded costs on the other. The increasingly competitive nature of the electric utility industry makes the latter considerations more compelling today than in previous years. The Commission concludes that its decision in previous biennial proceedings strikes an appropriate balance of these concerns. Consistent with its determination in the previous biennial proceeding, the Commission concludes in this proceeding that CP&L, Duke, and NC Power should each offer long-term levelized rate options of 5-year, 10-year and 15-year terms to hydro QFs of 5 MW or less and to non-hydro QFs of 5 MW or less fueled by trash or methane from landfills or hog waste. These long-term rate options are more limited than in the past; these limitations serve important statewide policy interests while reducing the utilities' exposure to overpayments. The policy interests to be served are those such as G.S. 62-156(b)(1), which specifically provides that long-term contracts "shall be encouraged in order to enhance the economic feasibility of small power production facilities." This is a statewide policy and it supports our requiring long-term rate options for hydro QFs. G.S. 130A-309.01 et al, provides a statewide policy of reducing and managing solid waste landfills, and we believe that it supports extending these options to facilities fueled by trash or methane from landfills. Although there is no specific statute as to hog waste, the Commission nonetheless believes that there is an environmental policy to be served by encouraging facilities fueled by methane from hog waste. While the Commission believes that these policies should be furthered, the Commission is also concerned about reducing the utilities' exposure to overpayments, and our decision does this as well. The facilities entitled to long-term rates are generally of limited number and size. Few, if any, new hydro facilities are being certificated; most sites are already developed. The number of trash and methane sites large enough to support generation is also probably limited. Although G.S. 62-156(b)(1) applies to hydros of 80 MW or less, there are few large hydro sites available in North Carolina, and the Commission has limited long-term rates to hydros contracting to sell 5 MW or less in order to further reduce the exposure inherent in rates based on long-term forecasts of the utilities' costs. Reducing the utilities' risks in this way is an appropriate response to the more competitive environment of the electric utility industry today.

Nevertheless, the Commission is not persuaded that the 15-year rate option should be applicable from the date a new plant goes into service as proposed by Southeastern, rather than the date the contract is signed. The Commission is also not persuaded that the long-term rate options should offer a "fixed" option as proposed by Southeastern, rather than the "levelized" rates adopted herein and in prior proceedings.

As to QFs other than hydros of 5 MW or less and non-hydros of 5 MW or less fueled by trash or methane from landfills or hog waste, CP&L and Duke proposed to offer a standard 5-year levelized rate option to other QFs who contract to generate 3 MW or less capacity. As it did in the previous proceeding, NC Power has proposed to restrict its standard 5-year levelized rate option to QFs other than those eligible for 10-year and 15-year terms herein who desire to sell 100 kW or less generating capacity. As in previous proceedings, NC Power proposes to offer a fixed long-term levelized energy payment as an option to small QFs rated at 100 kW or less capacity.

The Commission is of the opinion that there is still sufficient merit in its adoption of one size limit for 5-year rates in the previous proceeding to warrant its adoption in this proceeding. Therefore the Commission concludes that CP&L, Duke and NC Power should offer a standard 5-year levelized rate option to QFs not eligible for the 10-year and 15-year levelized rate options adopted herein who contract to sell 3 MW or less capacity. However, as in previous biennial proceedings, the Commission approves the NC Power proposal to offer a fixed long-term levelized energy payment as an option to small QFs rated at 100 kW or less capacity.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

In earlier biennial proceedings, the Commission ordered that QFs not entitled to the standard long-term levelized rate options had the options of selling energy only at the variable rates set by the Commission or of negotiating contracts and rates with the utility. As utilities began to pursue competitive bidding for new capacity needs, the Commission ordered that utilities could require QFs not entitled to the standard long-term levelized rate options to participate in the bidding, rather than negotiating contract rates and terms. The Commission discussed this issue in a previous biennial proceeding (Docket No. E-100, Sub 74) and concluded that the exact point at which a utility could invoke a refusal to negotiate and require a QF to participate in bidding should be resolved by motion to the Commission.

Consistent with these earlier decisions, the Commission concludes in this proceeding that QFs not eligible for the standard long-term levelized rates established herein should have the options of contracts to sell energy only at the variable rates established by the Commission or, as appropriate, contracts and rates derived by free and open negotiations with the utility or participation in the utility's competitive bidding process for obtaining additional capacity.

If the QF undertakes negotiations with the utility, the Commission has stated in previous orders that the utility should negotiate in good faith for terms fair to the QF and ratepayers, that a QF may file a complaint if it feels that a utility is not negotiating in good faith, and that various factors listed by the Commission should be considered. There is no need to repeat these guidelines; they have been stated numerous times in past orders (see, e.g., the discussion of Findings of Fact Nos. 34 and 35 in the June 23, 1995 Order in Docket No. E-100, Sub 74), and these provisions remain in effect.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

CP&L and Duke have used the peaker methodology to develop their avoided costs in each of the past several avoided cost proceedings; NC Power has used the differential revenue requirement (DRR) methodology. Each utility proposes to continue using the same respective methodology in this proceeding. Various concerns have been expressed in these biennial proceedings concerning the divergence between the utilities' retail rates and their avoided cost rates, the utilities' short-term need for more peaking capacity versus their long-term need for more base load capacity, the appropriate application of the peaker and DRR methodologies in a manner that would avoid understating avoided costs, and the low level of QF activity occurring in the State. As a result, in previous biennial avoided cost proceedings, the Commission made detailed examinations of avoided cost methodologies. The examinations focused for the most part on three primary methods that have been used to estimate the cost of avoided capacity and energy: the peaker method, the DRR method, and the proxy unit method.

The peaker methodology used by CP&L and Duke is based on a method for estimating marginal costs developed by the National Economic Research Associates, Inc. (NERA). The method was described in detail in what became known as the "Grey Books" series of publications, jointly sponsored by the National Association of Regulatory Utility Commissioners, the Electric Power Research Institute, the Edison Electric Institute, the American Public Power Association, and the National Rural Electric Cooperative Association. It is one of four marginal costing methodologies developed in the "Electric Utility Rate Design Study" portion of the "Grey Books" series (Topics 1.3 and 1.4).

According to the theory underlying the peaker method, if the utility's generating system is operating at equilibrium (i.e., at the optimal point), the cost of a peaker (a combustion turbine or CT) plus the marginal running costs of the system will produce the utility's avoided cost. Theoretically, it will also equal the avoided cost of a baseload plant, despite the fact that the capital costs of a peaker are less than those of a baseload plant.

In theory, the lower capital costs of the CT are offset by the fuel and other operation and maintenance expenses included in system marginal running costs, which are higher for a peaker than for a new baseload plant. The theory indicates that the summation of the peaker capital costs plus the system marginal running costs will match the cost per kWh of a new baseload plant—assuming the system is operating at the optimum point. Put another way, the fuel savings of a baseload plant will offset its higher capital costs, producing a net cost equal to the capital costs of a peaker.

The DRR methodology involves a comparison of the revenue requirements which result from two alternative system expansion plans—one including a block of new QF capacity and the other excluding such a block. The utility's generation costs are calculated on a yearly basis for an extended period of time for each of these two scenarios. The difference between the two scenarios is then computed for each year, and the results converted into present value terms, thereby providing an estimate of the present value of the total avoided cost of the assumed block of QF capacity.

The proxy unit methodology uses a specific plant as a proxy unit for calculating avoided costs. It argues that the peaker and DRR methods both mismatch low baseload fuel costs with low peaker capital costs, and that either (1) the higher fuel costs of a peaker should be used with the lower capital cost of a peaker, or (2) the lower fuel cost of a baseload unit should be used with the higher capital cost of a baseload unit.

In previous biennial proceedings, the Commission concluded that it should not require CP&L, Duke, and NC Power to utilize a common methodology for calculating avoided costs. There are obviously widely divergent opinions among even those who are most expert in these matters as to what costs are actually avoided and what methodologies will best identify those costs. The peaker method and the DRR method are generally accepted and used throughout the electric utility industry. NC Power's comparison of the results of the peaker and DRR methodologies as applied to them in a previous proceeding showed very little difference between the methodologies.

The Commission also concluded in previous biennial proceedings that it should not require the utilities to adopt a specific generating unit or type of unit for calculating avoided costs. The Commission has consistently found in previous biennial proceedings that the avoided cost of a utility system is not necessarily unit specific. Addition or deletion of a given generating unit affects how the remaining generating units are run. The economics of a generation <u>mix</u> is usually determinative, not the economics of a single unit.

For the purposes of this proceeding, the Commission concludes that both the peaker method and the DRR method are still generally accepted and used throughout the electric utility industry and are reasonable for use herein. No party to this proceeding advocated that the Commission should revise its conclusions in the previous biennial proceedings regarding appropriate methodologies.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 AND 7

Avoided cost capacity rates established by the Commission using the peaker methodology have included a performance adjustment factor in previous proceedings, the function of which is to allow a QF to experience some level of outages and yet still recover its full capacity credits. The calculation of a performance adjustment factor is a specific part of developing avoided cost capacity rates under the peaker methodology. A performance adjustment factor is not an essential part of calculating avoided cost capacity rates under the DRR method, and this is therefore not an issue as to NC Power.

The Commission found in previous biennial proceedings that a performance adjustment factor of 1.2 is appropriate for CP&L and Duke for all QFs except hydro facilities with no storage capability and no other type of generation and that a performance adjustment factor of 2.0 is appropriate for such hydro facilities. The use of a 1.2 performance adjustment factor requires a QF to operate 83% of the time in order to collect its entire capacity credit, and the use of a 2.0 performance adjustment factor requires a QF to operate 50% of the time in order to collect its entire capacity credit. All parties generally agree that a QF should be allowed to have some appropriate level of outages without losing the ability to earn full capacity credits; the issue is the appropriate outage level to incorporate into the avoided cost capacity rate through the performance adjustment factor.

CP&L reached a compromise agreement with the Public Staff in a previous biennial proceeding that it would use a 1.2 performance adjustment factor for all QFs except hydro facilities with no storage capability and no other type of generation and that it would use a 2.0 performance adjustment factor for such hydro facilities. The Commission adopted the CP&L/Public Staff compromise in that proceeding as applicable to both CP&L and Duke. In the current biennial proceeding, CP&L again proposes to use the same set of performance adjustment factors.

The Public Staff contended in the current proceeding that the Commission should continue to prescribe a 1.2 performance adjustment factor for calculating avoided capacity costs, just as in previous proceedings. This performance adjustment factor allows a QF to experience outages 17% of the time and still receive its full capacity credits. The Public Staff further contended that G.S. 62-156 encourages hydro generation, that hydro generation is environmentally friendly, and that run-of-river hydro facilities are generally unable to control the availability of their "fuel" and thus the timing of their capacity deliveries. The Public Staff therefore continued to support use of a 2.0 performance adjustment factor for hydro facilities with no storage capability and no other type of generation.

Duke again contended in the current proceeding that the performance adjustment factor should be 1.129, which is comparable to the approximate 89% availability of its peaking units. (Duke called its proposed factor a "CT Availability Adjustment Factor.") Duke stated that the performance adjustment factor should be based upon neither a planning reserve margin (because a reserve margin incorporates factors such as load forecast error, weather variations and other unexpected operating conditions), nor upon the capacity factors of the utility's units or system (because the utility's capacity factors are influenced primarily by economic dispatch, not forced and schedule outages). Duke has made this argument in the last several avoided cost proceedings, but it has consistently been rejected by the Commission.

The Commission has carefully reviewed all of the comments on this issue and concludes that a performance adjustment factor of 1.2 should continue to be used by CP&L and Duke in determining the avoided capacity cost rates for all QFs other than hydroelectric facilities with no storage capability and no other type of generation. This decision is generally based on the comments of the parties in this proceeding and is also consistent with previous Commission decisions.

The Commission also concludes that a performance adjustment factor of 2.0 should be utilized by CP&L and Duke in determining the avoided capacity cost rates for hydroelectric facilities with no storage capability and no other type of generation. This is also consistent with previous Commission decisions. Use of a higher performance adjustment factor for these hydro facilities allows them to operate less in order to receive the full capacity payments to which they are entitled, and this seems appropriate and reasonable considering the limitations on their control of their generation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 and 9

CP&L originally proposed rates with capacity credits that were calculated using avoided cost estimates that excluded the capital costs of land, transmission facilities, gas pipeline facilities, and initial fuel. The Public Staff responded that such costs should be included in the capacity credit calculations. CP&L then filed revised rates with capacity credits that are calculated using avoided cost estimates that include the capital costs of land and transmission facilities but still exclude the capital costs of gas pipeline facilities and the initial cost of fuel.

CP&L stated that it had discussed its revisions with the Public Staff and believes that they are in agreement on the revisions. CP&L contends that the gas pipeline capital costs should not be included as avoidable capacity credit costs because such capital costs are passed on to CP&L by each respective LDC in the delivery cost of gas and are therefore reflected in the avoidable energy credit costs as a part of the cost of fuel. Likewise, CP&L contends that the cost of fuel, initial or otherwise, is expensed as it is consumed and is thus reflected in the avoidable energy credit costs as a part of the cost of fuel. In addition, CP&L contends that the cost of working capital associated with maintaining fuel inventory is also accounted for in calculating avoidable energy credit costs.

The Commission is of the opinion that the CP&L/Public Staff compromise on this matter is reasonable, and concludes that CP&L should be required to include the capital costs of land and transmission facilities in its calculations of capacity credits.

NC Power originally proposed rates with capacity credits that were calculated using avoided cost estimates that excluded the capital costs of land. The Public Staff responded that such costs should be included in the capacity credit calculations. NC Power responded that it agreed land costs should be included in the calculations in cases where land costs could actually be avoided. However, the company pointed out that new capacity is sometimes added at existing sites where land costs cannot be avoided. Nevertheless, NC Power stated in its Reply Comments that it agrees to refile its rates to include land costs in its capacity credits.

The Commission is of the opinion that it should adopt NC Power's agreement to include land costs in its capacity credits, and concludes that NC Power should be required to include the capital costs of land in its calculation of capacity credits for purposes of this proceeding.

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

Southeastern Hydro-Power (Southeastern) proposed in its comments to eliminate the standard contract requirement that the utility have exclusive rights to purchase power from a QF when its initial contract with that QF comes up for renewal. Duke responded that its standard contract requirement has been approved by the Commission in previous proceedings and that it preserves Duke's rights to capacity which its previous capacity credits have paid for. As in previous proceedings, the Commission concludes that the standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration.

Southeastern also proposed in its comments that all standard contracts include a requirement specifying that all environmental and resulting financial rights (such as air quality credits) will remain with the QF. Duke responded that if a QF wishes to retain such rights, it should refrain from opting for the standard long-term contracts under PURPA. The Public Staff observed that the Southeastern proposal was not fully discussed by all parties and should not be acted upon without further discussion.

The Commission is of the opinion that it would be premature to adopt such a standard contract requirement as that proposed by Southeastern. However, the Commission does not wish for its denial of the proposal in this proceeding to cut off further discussion of the matter in future proceedings. Therefore, the Commission concludes that Southeastern's proposal that standard contract language be required specifying that all environmental and resulting financial rights will remain with the QF should be denied without prejudice to further discussion of the issue in future proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The rate schedules and standard contracts proposed by CP&L, Duke, and NC Power in this proceeding are reasonable except as discussed herein, and they should be approved subject to the modifications required by this Order. The Commission has considered the objections to CP&L's avoided cost calculations submitted by Lockville Hydropower, and concludes that they do not justify reaching a different result. CP&L, Duke, and NC Power will need to file new versions of their rate schedules and standard contracts within 10 days after the date of this Order in order to implement this Order. They should also file supporting documentation showing the calculations made to arrive at their avoided cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence pertaining to WCU's calculation of avoided costs is contained in the testimony and exhibits of WCU witness Knowles, which were stipulated into the record without witness Knowles being called to testify. WCU does not generate its own electricity but buys its power wholesale from Nantahala at rates approved by the FERC. The avoided cost formula proposed by WCU would reimburse a QF based on the rates charged to WCU by Nantahala at any point in time, and it is the same formula approved by the Commission in previous avoided cost proceedings. No party challenged the avoided cost formula proposed by WCU. The Commission concludes that WCU's proposed Small Power Production Supplier Reimbursement Formula should be approved. Consistent with our conclusions in past proceedings, WCU should not be required to offer any long-term levelized rate options.

IT IS, THEREFORE, ORDERED as follows:

1. That CP&L shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. CP&L shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

2. That Duke shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. Duke shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity.

3. That NC Power shall offer long-term levelized capacity payments and energy payments based on a long-term levelized generation mix with adjustable fuel prices for 5-year, 10-year and 15-year periods as standard options to (a) hydroelectric qualifying facilities owned or operated by small power producers as defined in G.S. 62-3(27a) contracting to sell 5 MW or less capacity and (b) non-hydroelectric qualifying facilities fueled by trash or methane derived from landfills or hog waste contracting to sell 5 MW or less capacity. The standard levelized rate options of 10 years and 15 years should include a condition making contracts under those options renewable for subsequent term(s) at the option of the utility on substantially the same terms and provisions and at a rate either (1) mutually agreed upon by the parties negotiating in good faith and taking into consideration the utility's then avoided cost rates and other relevant factors or (2) set by arbitration. NC Power shall offer its standard 5-year levelized rate option to all other qualifying facilities contracting to sell 3 MW or less capacity. NC Power shall offer long-term levelized energy payments as an additional option for small QFs rated at 100 kW or less capacity.

4. That CP&L, Duke and NC Power shall offer qualifying facilities not eligible for the standard long-term levelized rates the options of contracts to sell energy only at the variable rates established by the Commission or, as appropriate, contracts and rates derived by free and open negotiations with the utility or participation in the utility's competitive bidding process for obtaining additional capacity.

5. That the rate schedules and standard contract terms and conditions proposed in this proceeding by CP&L, Duke, NC Power, and WCU are hereby approved except as otherwise discussed herein.

6. That CP&L, Duke, NC Power, and WCU shall file within ten (10) days after the date of this Order rate schedules and standard contract terms and conditions implementing the findings, conclusions and ordering paragraphs herein. Additionally, CP&L, Duke and NC Power shall file supporting documentation showing the calculations made to arrive at their avoided cost rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva Thigpen, Chief Clerk

je040501.01

DOCKET NO. E-100, SUB 88

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Investigation of Integrated Resource Planning in North Carolina - 2000	) ORDER APPROVING) INTEGRATED RESOURCE) PLANS

BY THE COMMISSION: North Carolina General Statute 62-110.1(c) requires the North Carolina Utilities Commission (Commission) to "develop, publicize, and keep current an analysis of the long-range needs" for electricity in this State. This includes (1) the Commission's estimate of the probable future growth of the use of electricity; (2) the probable needed generating reserves; (3) the extent, size, mix and general location of the generating plants; (4) arrangements for pooling power to the extent not regulated by the Federal Power Commission (now the Federal Energy Regulatory Commission, or the FERC); and (5) other arrangements with other utilities and energy suppliers.

The purpose of this requirement is "to achieve maximum efficiencies for the benefit of the people of North Carolina." The statute requires the Commission to develop a plan for the future requirements for electricity for North Carolina or the area served by a utility and to consider its analysis in acting upon any petition for construction. In addition, it requires the Commission to submit annually to the Governor and to the appropriate committees of the General Assembly the following: (1) a report of its analysis and plan; (2) the progress to date in carrying out such plan; and (3) the program of the Commission for the ensuing year in connection with such plan.

Commission Rule R8-60 requires that each of the investor-owned utilities and the North Carolina Electric Membership Corporation (collectively, the utilities) furnish the Commission with an annual report that contains specific information that is set out in subsection (c) of the Rule and provides that the Public Staff and any other intervenor may file its own report, evaluation, or comments regarding the utilities' reports. In addition, Rule R8-62(p) requires certain additional information be included in the reports about the construction of transmission lines.

In its July 13, 1999, Order Adopting Least Cost Integrated Resource Plans And Clarifying Future Filing Requirements in Docket No. E-100, Sub 82, the Commission imposed additional requirements for the annual reports. Specifically, the utilities were directed to include a full response to each item of information required by the Rules; appropriate explanations for each item where the information requested is not available; and appropriate explanations referencing the location of information in the filings where such information does not follow the same general order of presentation as contained in the Commission Rules. The Commission further ordered the utilities to adhere to the requirement that each ten-year forecast and plan consist of the ten years next succeeding the annual September 1 filing date. Finally, in that order and subsequent proceedings, the Commission required the utilities to file in their annual reports a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of projected reserve margins and a discussion of the adequacy of the respective utility's transmission system.

On or about September 1, 2000, the current Integrated Resource Plan (IRP) filings were made under the Commission's Rules by Carolina Power & Light Company (CP&L), Duke Power (Duke), Dominion North Carolina Power (NC Power), and North Carolina Electric Membership Corporation (NCEMC). On November 30, 2000, the Public Staff filed its comments on the IRPs filed by the utilities.

Carolina Industrial Group for Fair Utility Rates I and II (CIGFUR) intervened in the proceeding but did not file comments.

A public hearing was held on February 13, 2001, in Raleigh for the purpose of taking non-expert public witness testimony. No one appeared to testify at the hearing.

An informational presentation was held before the Commission on March 12, 2001, in Raleigh for the purpose of receiving more information from the utilities regarding: (1) the adequacy of electric power supply in North Carolina, including each utility's projected reserve margins, the status of each utility's plans to meet its anticipated load growth, and the status of each utility's plans to acquire additional capacity; and (2) the adequacy and reliability of each utility's transmission/distribution systems, including the extent to which there are any transmission constraints or other limitations which prevent the importation of significant amounts of electric power into any part of North Carolina.

At the informational presentation, CP&L presented a panel consisting of Skip Orser, its President for the Energy Supply Group; Verne Ingersoll, its Director of Regional Planning; and Randy Wilkerson, its Director of Power System Operations.

Duke presented a panel consisting of Steve Young, its Vice President for Rates and Regulatory Affairs; Scott Henry, its Manager of Energy Procurement; and Bob Pierce, its Senior Engineer for Transmission Engineering and Planning.

NC Power presented a panel consisting of Charles Stadelmeier, its Manager of Pricing and Regulatory Affairs; Phil Powell, its Director of System Protection and Transmission Planning; and Bob Wilson, its Lead Market Analyst.

NCEMC presented David Beam, its Senior Vice President for Power Supply.

COMPLIANCE WITH FILING REQUIREMENTS

The Public Staff comments contained a summary of the utilities' responses to information requirements contained in Rules R8-60(c) and R8-62(p). All responses were positive, according to the Public Staff.

DEMAND SIDE MANAGEMENT (DSM) OPTIONS

The Public Staff comments contained the following summary of its review of DSM options:

> The utilities' emphasis on DSM has waned since discussions began on restructuring the regulated electricity industry. The Public Staff recommends the Commission continue to monitor and evaluate the appropriateness of the utilities' DSM efforts.
>
> All of the utilities complied with the letter of Rule R8-60(c)(9), which requires only a list of demand side options reflected in the resource plan. Each utility, in its original plan filing, provided at least a list of current DSM programs. Notably, most utility programs designated as DSM resources in the 1999 IRP reports are also included in the 2000 IRP annual reports.
>
> G.S. 62-2(3a) provides that it is the policy of this State "[t]o 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. . ." and "[t]o 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. . ." None of the utilities' filings listed any planned programs, new programs under consideration, or modifications to existing programs.

RESERVE MARGINS

The Commission Order Adopting Integrated Resource Plans, issued June 21, 2000, in Docket No. E-100, Sub 84, required that future IRP filings by all utilities shall include a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of the respective utility's projected reserve margins. The Public Staff's written comments contained the following discussion of the utilities' response to the reserve margin requirement:

(1) CP&L provided an assessment of the adequacy and appropriateness of its level of projected reserves. CP&L did not provide a target reserve margin or reserve level as provided last year, but asserted that the reserve margin range of 11.7% to 14.5% for this period was adequate. CP&L found that the industry's widely used "one day in ten years" Loss-of-Load Expectation (LOLE) criteria would be satisfied by its filed reserve margins for the planning period. CP&L used computer modeling, its own studies, and assessment of capacity assistance from neighboring electric systems to evaluate the reliability criteria. CP&L also stated its belief that the high reliability and small size of planned additions allow these lower reserve margins.

(2) Duke responded that its reserve margin target of 17% was supported by the increased availability of existing generation, shorter lead times for new generation, and the emergence of new purchased power options. Duke also factored in Its operating experience when it selected this 17% reserve margin. Duke reported that between June 1997 and July 1999, there were 15 days when generating reserves dropped below 3%, not including purchases and Demand Side Management (DSM). When purchases and DSM were included, the lowest reserve margin reached was 12%. Duke's actual reserve margin is slightly above the 17% target for the entire planning period.

(3) Dominion reported that its target reserve margin is 12.5%. In the past, Dominion established planning reserves using a 12-hour loss of load criterion. In 1999, Dominion initiated a review of this reserve planning criterion to evaluate its appropriateness. Dominion's results determined that a reserve margin of between 12% and 13% should be used as a target. An executive committee determined that a target reserve margin of 12.5% would be adequate to cover various contingencies.

(4) NCEMC did not provide an assessment of the adequacy of its reserve margin, as it expects its suppliers to provide adequate reserves for its contracted purchases.

The Public Staff believes that the Commission should continue to require the filing of reserve adequacy reports, including the criteria used to determine reserve margin targets, within the annual IRP reports. The information supplied is important and not found elsewhere. CP&L, Duke and Dominion appear to meet their projected reserve margin targets for the planning period. The Public Staff recommends that Duke and Dominion maintain reserve margins of approximately 17% and 12.5%, respectively, and feels that reserves will be adequate.

The utilities did not file written responses to the Public Staff comments.

At the informational presentation held on March 12, 2001, each utility's panel of witnesses presented details supporting its respective reserve margins, and responded to questions from the Commission regarding its generating reserves. CP&L's panel emphasized that the company has added over 1,300 megawatts (MW) of new generating capacity during the last four years, and plans to add 2,400 MW of additional new capacity by 2003. It also emphasized that generator reliability has improved tremendously since the 1980s, resulting in lower reserve margin requirements. In addition, many new smaller individual generating units have been added, lessening the probability of concurrent outages affecting a significant amount of generating capacity. CP&L expects to have adequate generating capacity to supply forecast demand.

Duke's panel emphasized that interruptible resources currently provide about one-third of Duke's total reserve capacity at peak periods, and that its operating experience shows that its adopted 17% planning reserve margin target has resulted in limited activation of interruptible capacity resources. It also emphasized that its purchased power contracts and self-build proposals have been working together to ensure sufficient capacity to meet its load requirements, and illustrated its point by citing a 151 MW contract to purchase power from CP&L beginning in 2003 as well as plans to self-build 640 MW beginning in 2003. Duke projects that its existing and planned resources will be adequate to meet its forecast demands.

NC Power's panel emphasized that the company would continue to purchase outside power as well as self-build generation in order to meet its forecast needs, and it described the combination of resources that NC Power will use to maintain its 12.5% planning reserve margin.

Mr. Beam of NCEMC described NCEMC's arrangements for providing capacity resources for its member cooperatives, including a competitive bidding process for obtaining future new capacity. He also pointed out that NCEMC does not carry a reserve margin, but relies upon its suppliers to provide necessary reserves.

TRANSMISSION ADEQUACY

The Commission Order Adopting Integrated Resource Plans, issued June 21, 2000, in Docket No. E-100, Sub 84, required that future IRP filings by all utilities shall include a discussion of the respective utility's transmission system (161 kV and above).

The Public Staff's written comments contained the following discussion of transmission adequacy:

> During the 1999 annual report reviews, the Public Staff noted that the utilities included general statements describing the process for ensuring transmission system adequacy but did not provide sufficient technical details for assessing the impact of various planning elements. The Public Staff recommended that the Commission require the utilities to file six types of specific data in their next annual reports. Duke responded that much of this data is publicly available in reports and models. Duke further suggested that the Public Staff and the utilities meet to understand better each

party's position and possibly develop an efficient and responsive reporting mechanism. In its Order dated June 21, 2000 in Docket No. E-1 00, Sub 84, the Commission ordered that the IRP filings include a discussion of the efforts by the interested parties to develop an efficient and responsible reporting mechanism for transmission adequacy. On August 15, 2000, and September 6, 2000, the parties met and the Public Staff was provided with over 850 pages of reports filed with the Federal Energy Regulatory Commission (FERC), and reports prepared by the North American Electric Reliability Council (NERC), the Southeastern Electricity Reliability Council (SERC) and its sub-region VACAR. These reports contain detailed information regarding national, regional and sub-regional reliability assessments. The Public Staff is currently reviewing these reports, attempting to extract the data that it recommended for inclusion in the IRP annual reports and claimed by Duke to be contained in these reports. The Public Staff recommends that the Commission require the parties to continue their dialog and conclude it in time to incorporate the appropriate transmission information in the 2001 annual report.

The utilities did not file written responses to the Public Staff comments.

At the informational presentation held on March 12, 2001, each utility's panel of witnesses presented details supporting its respective transmission planning, and responded to questions from the Commission regarding its transmission system. CP&L's panel emphasized that the Company maintains a reserve margin on its transmission system of approximately 1,800 MW in order to retain the ability to import significant amounts of emergency power in the event of large generation outages. It also participates in coordinated regional planning studies with its neighboring utilities in order to assure that the transmission system can support planned regional purchases and sales. CP&L expects to have adequate transmission capacity to supply system loads and firm transmission commitments.

Duke's panel emphasized its planning process for transmission upgrades in which it annually screens its transmission grid to identify those segments most in need of expansion or other upgrading. It also described how GridSouth, a regional transmission operator, will interact with Duke in the transmission planning process. The panel pointed out that the transmission system of each utility was originally built for local purposes, and that such transmission systems are designed, constructed and operated very well for their intended purposes. However, upgrades will be required in order to cope with the open market for long distance power purchases. Duke expects to have adequate transmission capacity to serve forecast demands.

NC Power's panel emphasized its transmission planning process, and described details of upgrades it is planning for its North Carolina service area. The panel also described its "first contingency" analysis, in which system improvements are based on calculated facility loading and voltage with a critical facility outage in effect under certain forecasted loads.

Mr. Beam of NCEMC pointed out that NCEMC does not have transmission resources of its own, and that it strongly supports formation of an independent regional transmission organization.

CONCLUSIONS

Demand Side Management (DSM) Options

The Commission recognizes the value of cost-effective DSM programs, and concludes that it should encourage the appropriate application of DSM options to the total resource mix of each utility.

Reserve Margins

The Commission recognizes that the electric power industry is in the midst of a time of economic and regulatory transition and that the resulting changes have led to the rethinking of certain long-accepted industry standards, As a result of these changes and the amount of information contained in the present record, the Commission does not believe that it is appropriate to mandate the use of any particular reserve margin for any jurisdictional electric utility at this time. For this reason, the Commission concludes that it would be more prudent to monitor the situation closely, to allow all parties the opportunity to address this issue in future filings with the Commission, and to consider this matter further in subsequent integrated resource planning proceedings. At this point, the Commission believes that existing generation resources are adequate in light of current conditions. The Commission does, however, want the record to clearly indicate that providing adequate service is a fundamental obligation imposed upon all jurisdictional electric utilities, that it will be actively monitoring the adequacy of existing electric utility reserve margins, and that it will take appropriate action in the event that any reliability problems develop.

The Commission concludes that future IRP filings by all utilities should continue to include a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of the respective utility's projected reserve margins.

Transmission Adequacy

The Commission notes that much of the transmission data recommended by the Public Staff is provided in some form or other by each utility for use in the joint engineering studies of system reliability conducted by VACAR and SERC on an ongoing basis. Nevertheless, it is not clear how difficult it would be to compile the data in the form needed for an IRP filing. SERC's report to NERC addresses the same concerns about transmission adequacy, but it does not contain a compilation of the detailed data recommended by the Public Staff.

The Commission concludes that the parties should be required to continue their dialogue regarding an efficient and responsive reporting mechanism for transmission adequacy and complete such dialogue in time to incorporate the appropriate information in the IRP filings due September 1, 2001.

The Commission further concludes that future IRP filings by all utilities should continue to include a discussion of the adequacy of the respective utility's transmission system (161 kV and above).

Approval of IRPs

As indicated in earlier IRP dockets, the Commission is of the opinion that the IRP review is intended to ensure that each utility is generally including all of the considerations in its planning as required by the Commission's Rules; that each utility is generally utilizing state-of-the-art techniques for its forecasting and planning activities; and that each utility has developed a reasonable analysis of its long-range needs for expansion of generation capacity. Also, the Commission is of the opinion that evaluations of individual DSM programs, certificates to construct new generating plants or transmission lines, and individual purchased power contracts should be handled in separate dockets from the IRP proceeding. Consistent with this view, it should be emphasized that inclusion of a DSM program, proposed new generating station, proposed new transmission line or purchased power contract in the IRP does not constitute approval of such individual elements even if the IRP itself is approved.

The Commission concludes that the current IRPs should be approved. No party has argued that the IRP filed by any utility should be rejected.

IT IS, THEREFORE, ORDERED as follows:

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

2. That the Integrated Resource Plans filed by CP&L, Duke, NC Power, and NCEMC in this proceeding are hereby approved as hereinabove discussed;

3. That future IRP filings by all utilities shall continue to include a detailed explanation of the basis for, and a justification for the adequacy and appropriateness of, the level of the respective utility's projected reserve margins.

4. That future IRP filings by all utilities shall continue to include a discussion of the adequacy of the respective utility's transmission system (161 kV and above); and

5. That the Public Staff and the utilities shall conclude their dialogue regarding efforts by the interested parties to meet and develop an efficient and responsive reporting mechanism for transmission adequacy in time to incorporate the appropriate information in the IRP filings due September 1, 2001.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

je040201.01

DOCKET NO. E-100, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Oversight of Electric Membership Corporations Pursuant	)	ORDER ADOPTING
to G.S. 62-53 and 117-18.1	)	RULE R19-1

BY THE COMMISSION: On June 10, 1999, the North Carolina General Assembly ratified, and the Governor subsequently signed, House Bill 476, Session Law 1999-180. In pertinent part, this legislation amends the General Statutes to add G.S. 62-53 and G.S. 117-18.1. G.S. 62-53 provides that the Commission shall have the authority to regulate electric membership corporations (EMCs) as provided in G.S. 117-18.1. G.S. 117-18.1 authorizes EMCs to own and operate "separate business entities that provide energy services and products, telecommunications services and products, water, and wastewater collection and treatment," subject to certain conditions. One of those conditions is that the affiliated business entity fully compensate the EMC for the use of the personnel, services, equipment, or tangible and intangible property of the EMC at the greater of a competitive price or the EMC's fully distributed costs. The Commission is authorized, upon complaint showing reasonable grounds for investigation and after making certain findings, to direct the EMC to adjust charges to comply with the statute, and if the EMC does not comply with the Commission's directive, the Commission is authorized to direct the EMC to divest its interest in the other business entity. The Commission, the Commission Staff, and the Public Staff are authorized to inspect the books and records of the EMCs and such other business entities, and the Commission is authorized to adopt rules and reporting requirements in this regard.

Shortly after this legislation was enacted, the Public Staff began a series of meetings and site visits with a view toward proposing rules and reporting requirements appropriate to monitoring transactions between the EMCs and such affiliated business entities. On November 15, 2000, the Public Staff filed a Motion and Proposed Rule, which was amended on November 21, 2000, to correct an inadvertent omission. By its Motion, the Public Staff recommended that the Commission adopt its Proposed Rule and establish certain reporting requirements to enable the Commission and the Public Staff to monitor the cost allocations and transfer pricing for goods and services to and from the electric operations of the EMCs that engage in such other business activities pursuant to G.S. 117-18.1. On December 5, 2000, the Commission issued an Order Initiating Rulemaking in this docket. The Order allowed interested persons to intervene and file comments and reply comments on the Public Staff's Proposed Rule and proposed transaction report form, which were attached to the Order. Under the procedural schedule of the Order, petitions to intervene and comments were due on or before January 16, 2001 and reply comments were due on or before January 30, 2001. Said Order also required that the North Carolina Electric Membership Corporation (NCEMC) publish notice of this proceeding in newspapers having general circulation in the service areas of the EMCs once during the week of December 18, 2000.

On December 7, 2000, the NCEMC, which is a generation and transmission cooperative organized pursuant to Chapter 117 of the North Carolina General Statutes and is responsible for the power supply of its 26 member distribution cooperatives throughout the State, filed a Petition to Intervene. The Petition to Intervene was allowed by Order dated December 14, 2000.

On December 15, 2000, Duke Power, a division of Duke Energy Corporation (Duke) filed a Petition to Intervene, which was allowed by Order dated December 21, 2000.

On December 27, 2000, Carolina Power & Light Company (CP&L) filed a Petition to Intervene. The CP&L Petition to Intervene was allowed by Order dated January 2, 2001.

On January 16, 2001, the Carolina Utility Customers Association, Inc. (CUCA) and Piedmont Natural Gas Company, Inc. (Piedmont) filed Petitions to Intervene which were allowed by Order dated January 24, 2001. CUCA and Piedmont did not file comments.

PUBLIC STAFF'S PROPOSED RULE AND REPORTING REQUIREMENTS

As discussed above, on November 15, 2000, the Public Staff filed a Motion and Proposed Rule, which was amended on November 21, 2000 to correct an inadvertent omission. The Public Staff's Proposed Rule would require each EMC that is engaged or plans to engage in other business activities pursuant to G.S.117-18.1 to file: (1) a copy of its audited financial statements, on an annual basis; (2) an affiliate cost allocation manual, updated annually; (3) an annual report on affiliated transactions on a form which would be provided by the Commission; and (4) a code of conduct, updated annually. An EMC that is not engaged in such activities would only be required to file an annual statement that it is not engaged in such activities. The Public Staff's Proposed Rule does not address the Commission's authority to hear complaints against EMCs, presumably because the Commission already has rules and procedures in place for complaint proceedings.

NCEMC'S COMMENTS

On January 16, 2001, NCEMC filed comments in which it proposes changes to the Public Staff's Proposed Rule and proposed transaction report form and recommends that the Commission adopt NCEMC's Proposed Rule and transaction report form which is attached to its comments. NCEMC's proposed changes to the rule and form recommended by the Public Staff, and the reasons stated for these changes, are summarized below.

NCEMC's Proposed Rule

In some instances, NCEMC proposes changes to the language in the Public Staff's Proposed Rule in order to conform to the phrasing of the pertinent statutes. For example, NCEMC proposes to use the phrase "conduct the activities permitted by G.S. 117-18.1" as it appears in the new subdivision (14) of G.S. 117-18, rather than the phrase "business activities conducted through affiliates. . ." contained in the Public Staff's Proposed Rule. NCEMC pointed out that the word "affiliates" does not appear in House Bill 476 and could be interpreted as conveying a different meaning from that intended by the phrase "separate business entities" which is contained in G.S. 117-18.1(a).

According to NCEMC, several of its recommended changes would accomplish the goals of the Public Staff's Proposed Rule, but in a way that avoids undue burdens on EMCs. For example, Section (c)(4) of the Public Staff Proposed Rule requires each EMC which engages in business activities permitted by G.S. 117-18.1 to file "a code of conduct, updated annually." NCEMC represents that some state commissions have concluded that the costs and burdens of implementing codes of conduct outweigh the benefits of such codes. However, if the Commission decides to require codes of conduct from EMCs in this docket, NCEMC suggests that EMCs should be required to file a copy of a code of conduct as adopted by its board of directors, and thereafter, file any subsequently adopted changes to that code of conduct within a specific period before the effective date of the change. This would avoid annual filings of a code of conduct that may not be changed for several years. Attached to NCEMC's filing is an initial code of conduct which NCEMC proposes that each EMC operating a separate business entity would be required to file. As another example, NCEMC pointed out that section (c)(1) of the Public Staff's Proposed Rule would require EMCs to file "copies of its audited financial statements, on an annual basis." Instead, NCEMC proposes that EMCs which borrow funds guaranteed by the Rural Utilities Services of the U.S. Department of Agriculture (RUS) file "a copy of the annual publication of the [RUS], entitled Statistical Report—Rural Electric Borrowers, within sixty days of its publication. . ." and ". . . if the EMC is not a borrower of a loan guaranteed by the RUS. . ." then such an EMC would file ". . .a document presenting the equivalent information in a similar format. . ." NCEMC believes that the information contained in the RUS publication would accomplish the fundamental purposes of the Public Staff's proposal without requiring additional paperwork by an EMC or risking possible conflicts between the accounting standards required or permitted by the RUS (for borrowers) and Generally Accepted Accounting Principles (GAAP).

NCEMC suggests other changes to the Public Staff's Proposed Rule due to practical considerations. As one example, section (c) of the Public Staff's Proposed Rule would require EMCs to file several items annually if they "plan to engage" in separate business activities. Instead, NCEMC recommends that an EMC should comply with the filing requirements only if they actually operate a separate business entity pursuant to G.S. 117-18.1. Another change suggested by NCEMC due to practical considerations concerns section (c)(2) of the Public Staff's Proposed Rule, wherein EMCs would be required to file "an affiliate cost allocation manual, updated annually." According to NCEMC, because some EMCs are RUS borrowers and others are not, different accounting standards and procedures may have been adopted by different EMCs. As a result, there may be one or more allocation methods required or allowed under one accounting standard, and another method or methods allowed by another. In addition, a single EMC may operate several separate business entities and consistently use different cost allocation methods for each, without violating the accounting standards applicable to that EMC. Still further, NCEMC opines that requiring EMCs to file cost allocation manuals on an annual basis will not materially assist the Commission in fulfilling its responsibilities under G.S. 117-18.1. NCEMC believes that any methodology shown to be in accordance with the accounting principles and standards applicable to an EMC should be acceptable to the Commission. Rather than filing a cost allocation manual on an annual basis, sections (e) and (e)(1) of NCEMC's Proposed Rule would only require: a statement of the allocation method(s) used by the EMC to record transactions conducted pursuant to G.S. 117-18.1; and a statement that the allocation method(s) used conforms with either GAAP (if the EMC is not a RUS borrower) or with accounting principles required or allowed by RUS (if the EMC is a RUS borrower). Such statements would not be filed until 60 days after the Commission finds that an investigation should be commenced in response to a complaint alleging a violation of G.S. 117-18.1.

Another significant concern of NCEMC with the Public Staff's Proposed Rule is the failure to ensure that the material EMCs are required to file regarding separate business activities is kept confidential and does not become part of the public record. NCEMC states that the Commission's policies on collecting data from regulated participants in the electric utility industry should be designed to promote, rather than to hinder, efficient competition in non-regulated markets. Public disclosure of information that can affect pricing strategies, such as that included in cost allocation manuals, would place an EMC's separate business entities at a competitive disadvantage versus non-reporting marketing participants. NCEMC recommends that the Commission can satisfy its obligations under G.S. 62-53 and 117-18.1(a)(3) without public disclosure of such information and that the Public Staff's Proposed Rule should be amended to require that all such information be kept confidential. NCEMC's Proposed Rule section (f) would require all EMC filings pursuant to this rule to remain confidential.

NCEMC's Proposed Transaction Report Form

NCEMC believes the most prominent or important differences between the Public Staff and NCEMC in this proceeding arise from a difference in opinion regarding the role the General Assembly intended for the Commission in enacting G.S. 117-18.1, as well as the types of transactions which that statute limits. Such differences are reflected in each of these party's proposed transaction report form.

First, regarding the role intended for the Commission, NCEMC points out that the Public Staff's motion states that its proposals are intended. . ."[t]o enable the Commission and the Public Staff to monitor the cost allocations and transfer pricing for goods and services to and from the electric operations of the EMCs that engage in other business activities through affiliates pursuant to G.S. 117-18.1." (emphasis added by NCEMC). NCEMC states that the Public Staff recommends detailed filings annually regarding transactions and allocations in its proposed transaction report form because the Public Staff desires that the Commission adopt the role of a monitor. However, NCEMC believes the General Assembly has simply given the Commission discretion to commence an investigation, upon the filing of a complaint, if reasonable grounds exist for believing that an EMC has engaged in transactions which do not conform to the requirements of subdivision (a)(3) of G.S. 117-18.1. In other words, NCEMC believes the language of G.S. 117-18.1 does not impose or imply that the Commission act as an ongoing monitor of such activities or transactions. Second, regarding what types of transactions that the statute limits, NCEMC believes that G.S. 117-18.1 authorized the Commission to regulate transfers from EMCs to separate business entities operated by them (i.e., downstream transfers) but not transfers from separate business entities to EMCs (i.e., upstream transfers). According to NCEMC, the General Assembly did not choose to impose any limits on transfers to EMCs from a separate business entity because Section 117-18.1, on its face, does not set forth any transfer pricing rules or restrictions on the "upstream" transfer of property or services from a separate business entity to an EMC. NCEMC opines that because the authorizing legislation does not impose nor empower the Commission to promulgate any transfer or pricing rules or restriction with respect to transfers to EMCs, reporting of information applicable to such transfers is unnecessary. Therefore, based on statutory grounds, NCEMC suggests eliminating the requirements contained on the Public Staff's proposed transaction report form that EMCs file annual reports for each separate business entity detailing: (1) "loans to or from affiliate," (2) "Notes or accounts receivable from or payable to affiliate," (3) "[o]ther assets or liabilities related to affiliate,"

(4) "total dollar amounts for [nine] types of transaction[s] between the EMC and the affiliate, flowing in each direction," and (5) "contracts between the EMC and the affiliate." (emphasis added by NCEMC).

In addition, NCEMC also contends that some of the requested information contained in the Public Staff's proposed transaction report form appears to be directed at enforcement of provisions of G.S. 117-18.1 other than subdivision (a)(3). According to NCEMC, the General Assembly did not intend the Commission to enforce regulations for portions of G.S. 117-18.1 other than subdivision (a)(3). NCEMC believes that complaints regarding other provisions of G.S. 117-18.1 should be decided by the courts under the provisions of Chapter 117.

Consistent with its views regarding the role intended for the Commission under G.S. 117-18.1, the type of transactions which the statute limits, and the Commission's need to resolve only those issues arising under G.S. 117-18.1(a)(3), NCEMC submitted its own proposed transaction form for the Commission's approval. A copy of this form is attached to the comments of NCEMC.

In summary, NCEMC urges the Commission to consider the fundamental purposes of House Bill 476 when determining the nature and extent of regulatory "monitoring" needed to fulfill the Commission's role under this legislation. NCEMC submits that one of the fundamental purposes of House Bill 476 was to clarify the nature and extent of the authority of EMCs to operate or hold interests in entities that engage in activities permitted by G.S. 117-18.1. It believes that House Bill 476 was intended to allow EMCs to respond with new competitive options in the evolving environment now confronting providers of electricity, and to make a broader range of services available statewide. For EMCs, the difference between foregoing or undertaking an opportunity to provide new competitive options might be determined by regulatory compliance costs. Therefore, NCEMC requests that the Commission adopt its Proposed Rule, transaction report form, and code of conduct, as attached to its comments.

CP&L'S COMMENTS

CP&L states that its concern in this docket is that attempts may be made in the future to require CP&L to comply with the affiliate transaction reporting requirements established by the Commission for EMCs and their affiliates. According to CP&L, a balance must be achieved and maintained between the Commission's need for sufficient information to meet its statutory obligation to protect utility and EMC customers from any detrimental consequences of transactions between a utility or EMC and their affiliates versus the administrative burden to utilities and the EMCs from mandatory reporting requirements. CP&L believes that the annual affiliate transaction report proposed by the Public Staff in its Proposed Rule goes beyond what is needed by the Commission to fulfill those statutory obligations.

CP&L noted that it is currently required to file: a cost allocation manual; a code of conduct; and a list of shared services. CP&L must also promptly notify the Commission of any changes in any of these documents. In addition, CP&L is also required to file annual reports of affiliated transactions in a format to be prescribed by the Commission. In this docket, the Public Staff is proposing that the EMCs provide the Commission with similar information as well as audited financial statements. A cost allocation manual describes how CP&L or the EMCs will allocate costs between and among the utility or EMC and their affiliates. A code of conduct prohibits cross-subsidization and preferential treatment by the utility or EMC to their affiliates.

CP&L's concern with the Public Staff's proposal is the extremely detailed nature of the annual affiliate transaction report. CP&L believes that the annual list of affiliate transactions should simply identify the services that were actually provided by or to the utility or EMC and the affiliate or affiliates involved in the transaction. In CP&L's opinion, this information in conjunction with G.S. 62-153, provides the Commission with the information it needs to ensure that utility and EMC customers are not harmed by affiliate transactions. Further information is not helpful and simply represents an additional administrative burden to the utilities and EMCs.

DUKE'S COMMENTS

In its comments, Duke states that it is subject to affiliate transaction rules, and therefore has an interest in the rules and reporting requirement to be adopted by the Commission in this docket.

First, like NCEMC, Duke believes that the General Assembly set conditions on and authorized the Commission to regulate transfers from EMCs to their affiliates, but did not set conditions on transfers from affiliates to EMCs. Therefore, Duke recommends that the Public Staff's Proposed Rule and proposed transaction report form should be amended to delete references to transfers from affiliates to EMCs. Second, Duke states that the Public Staff's Proposed Rule and reporting requirements are overly burdensome and fail to protect confidential and proprietary information of EMCs and their affiliates. In particular, Duke noted that the proposed transaction report form requires substantial, duplicative and detailed information on both a categorical and transaction-by-transaction basis set out separately for each affiliate. Further, it does not include a materiality threshold to ensure that the required data is meaningful and useful. Duke takes the position that the volume of information and level of detail required by the Public Staff Proposed Rule and transaction report form is the type of information that would be requested and reviewed in a comprehensive audit or investigation, not the type of information that is reasonably and manageably compiled, assembled and reviewed on an annual basis. G.S. 117-18.1(a)(3) directs the Commission only to act upon a complaint showing reasonable grounds for investigation as opposed to monitoring cost allocations and transfer pricing. If the Commission requires EMCs to file information on an annual basis regarding affiliate transactions, such data should be reported at a high level, for example, by category or class, with a materiality threshold. In addition, Duke states that the Public Staff's Proposed Rule should be amended to provide that the information provided by the EMCs will be kept confidential. Third, Duke expresses its concern that the Public Staff has proposed extensive reporting requirements regarding (1) advertising and marketing, (2) use of brand name and logo, and (3) provision of "intangible benefits" related to the affiliates' use of EMC services, systems and resources, and public knowledge of the affiliation. While Duke acknowledges that G.S. 117-18.1(a)(3) specifically requires that affiliates compensate EMCs for use of certain intangible property, it is Duke's position that such restrictions on use of intangible assets such as name and logo are detrimental to customers, difficult to account for, and may be unconstitutional. Therefore, Duke urges the Commission to proceed with caution in its regulation of the use or transfer of EMCs' intangible property.

In summary, Duke believes that the Public Staff's Proposed Rule and transaction report form are not consistent with the statutory language in G.S. 117-18.1, overly burdensome, and fail to protect confidential information. Duke recommends that any rule and reporting requirements adopted by the Commission in this docket should: (1) be consistent with the actual transfer restrictions and pricing provisions set forth in the statute, (2) limit data disclosure to the information needed to exercise the Commission's authority as set forth in the statute, (3) be reasonable and manageable without causing EMCs to incur unnecessary cost, and (4) serve to promote competition in nonregulated markets without handicapping EMC affiliates.

PUBLIC STAFF'S REPLY COMMENTS

On January 30, 2001, the Public Staff filed reply comments in response to the comments filed by NCEMC, CP&L and Duke. In its reply comments, the Public Staff states that the primary difference between NCEMC's and its proposed rules is whether certain reports should be filed annually or upon an investigation of an EMC's affiliated transactions. The Public Staff attributes this difference to the parties' interpretations of the statutory basis of this rulemaking. According to the Public Staff, NCEMC apparently views the Commission's role and its authority to acquire information from the EMCs about the activities permitted by G.S. 117-18.1 as arising only when a complaint is filed by a competitor of an EMC affiliate. The Public Staff views the Commission's role more broadly. Since G.S. 117-18.1 grants the Commission authority to establish rules and reporting requirements to enforce its oversight responsibility, the Legislature recognized that a competitor's right to file a complaint with the Commission must be accompanied by Commission authority to maintain a contextual framework for examining specified affiliated activities of the EMCs. The Public Staff submits that its recommended reporting requirements are designed to provide the Commission with sufficient financial and cost information to exercise its complaint jurisdiction over affiliated transactions efficiently and effectively.

With respect to NCEMC's proposed changes, the Public Staff agreed with some, but disagreed with others, as discussed below.

First, the Public Staff does not oppose NCEMC's proposal to use the phrase "conduct the activities permitted by G.S. 117-18.1" instead of using the Public Staff's wording of "business activities through affiliates." Second, the Public Staff also agrees with NCEMC's proposal that an EMC operating separate business entities should be required to file a code of conduct with the Commission as adopted by that EMC's board of directors. Thereafter, an EMC which changes or amends its code of conduct would file the revised code of conduct prior to the effective date of the proposed change. Third, the Public Staff agrees to eliminate the phrase "plans to engage" from the Proposed Rule and transaction report form.

The Public Staff disagrees with NCEMC's proposal to file the RUS publication that contains certain financial information for EMCs that borrow from the RUS, or equivalent information for EMCs that do not borrow from the RUS, in lieu of audited financial statements as recommended by the Public Staff. Based on discussions with the EMCs, the Public Staff continues to believe that the simplest and preferred approach would be for each EMC to file its annual audited financial statements.

The Public Staff also opposes NCEMC's proposal that an EMC file a statement of allocation methods only after the Commission has initiated an investigation of an EMC. Instead, the Public Staff continues to be of the opinion that each EMC should file its cost allocation manual on an annual basis, or whenever there are significant changes in cost allocation methodologies. The Public Staff states that a cost allocation manual is an important reference document for an EMC's cost allocation policies and procedures and gives guidance to those making the actual accounting entries to ensure that affiliated transactions are correctly allocated and recorded.

Concerning the reporting requirement forms for affiliated transactions, the Public Staff also disagreed with NCEMC's proposal that an EMC file NCEMC's proposed transaction report form after a complaint investigation is commenced by the Commission. In contrast, the Public Staff continues to recommend that each EMC should report the dollar amounts of transactions with separate business entities associated with the use of personnel, services, equipment, or tangible, or intangible property on the transaction report form proposed by the Public Staff on an annual basis in order to facilitate the oversight responsibilities of the Commission.

As described hereinabove, NCEMC takes issue with reporting on transactions to and from EMCs and their separate business entities based on the grounds that the legislation does not, on its face, impose any limits or restrictions on transfers to EMCs from separate business entities. The Public Staff takes the position that the only information requested on its proposed report forms regarding the costs of goods or services provided to EMCs from separate business entities is summary information intended to provide the Commission with an overall understanding of the relationships between the entities and to better understand the general nature of an EMC's affiliate transactions and accounting. The Public Staff acknowledges that G.S. 117-18.1 does not explicitly provide for rules on transfers to EMCs from affiliates, but neither does the statute prohibit the Commission from requesting such information.

Finally, with respect to NCEMC's position that all EMC filings regarding separate business entities should remain confidential pursuant to language included in NCEMC's Proposed Rule, the Public Staff responds that it understands NCEMC's concerns about such sensitive information. However, the Public Staff recommends that the EMCs should assert, on a case-by-case basis, that certain information constitutes a trade secret and should be treated as confidential under the Public Records Act, rather than declaring all EMC filings are confidential in the rule.

With regard to CP&L's comments wherein CP&L expresses concern that it may be required to comply with the affiliate transaction reporting requirements established for the EMCs, the Public Staff states that CP&L's concern is misplaced. The Public Staff notes that no party has requested that the proposed reporting requirements be made applicable to anyone other than the EMCs and believes such requirements are necessary for the effective oversight of EMC-affiliated transactions.

With respect to Duke's comments, the Public Staff replies that Duke's transfer pricing is not at issue in this docket. Further, the Public Staff's reply to NCEMC's comments addresses the concerns raised by Duke regarding confidentiality and reporting requirements, as summarized above. And finally, although Duke expresses concern over the regulation of the use or transfer of an EMC's intangible property, the Public Staff points out that the legislation specifically states that the separate business entities will fully compensate the EMCs for the use of intangible property of the EMC at the greater of a competitive price or the EMC's fully distributed cost.

DISCUSSION AND CONCLUSIONS

At the outset, it should be noted that the Public Staff and NCEMC have agreed that any EMC which does not conduct activities permitted by G.S. 117-18.1 would only be required to file an annual statement to that effect under the rule. Accordingly, the following discussion of the issues relates only to the reporting requirements of EMCs which are actually engaged in such activities.

In a general way, the major differences between the parties, particularly the Public Staff and the NCEMC, can best be explained by their differing views of what role the Legislature intended for the Commission in enacting G.S. 117-18.1. The Public Staff views the Commission as a monitor with oversight responsibilities. Therefore, the Public Staff's recommended reporting requirements would require the EMCs to file more information on an annual basis. NCEMC simply believes the Commission has been given the discretion to conduct a complaint investigation if reasonable grounds exist to believe that an EMC has engaged in transactions which do not conform to the requirements of only subdivision (a)(3) of G.S. 117-18.1. Therefore, under NCEMC's recommended reporting requirements, the only annual filing by EMCs would be the RUS publication (assuming there were no changes to existing codes of conduct), and thereafter, only an EMC which is involved in a complaint investigation would file additional information (such as statements regarding allocation methods and NCEMC's proposed transaction report).

Several issues have specifically been identified by the parties in their comments concerning the Proposed Rule and are discussed below.

Audited Financial Statements

The Public Staff recommends that EMCs file audited financial statements, on an annual basis, while the NCEMC recommends that EMCs file the annual RUS publication. The Commission concludes that EMCs should file audited financial statements on an annual basis. The contents of audited financial statements should be more predictable and reliable and provide useful and relevant information regarding an EMC's separate business activities. The contents of the annual RUS publication are unknown and can be changed by the RUS. Further, EMCs which do not borrow from the RUS are evidently not required to prepare and submit such information to the RUS, and presumably, would only submit such information to the Commission and not the RUS.

Cost Allocation Manuals

Generally speaking, a cost allocation manual describes how an entity has decided to allocate and record costs between and among itself and its affiliates. As such, a cost allocation manual is a tool which should communicate cost allocation guidelines and requirements to all employees involved in accounting and recording such transactions. In this case, the Public Staff recommends that EMCs which engage in separate business activities should file a cost allocation manual, updated annually or whenever there are significant changes in cost allocation methodologies. In contrast, NCEMC proposes that an EMC should only be required to file statements regarding the allocation method(s) used by the EMCs and whether such method(s) conforms to RUS requirements or GAAP. Further, NCEMC proposes that such statements would not be filed until after the Commission finds reasonable grounds to commence a complaint investigation. The Commission concludes that EMCs should be required to file a cost allocation manual, updated annually or whenever there are significant changes in cost allocation methodologies. The Commission believes this filing requirement will encourage EMCs to immediately establish allocation policies and procedures which should be consistently applied by informed employees with regard to activities permitted by G.S. 117-18.1. The Commission also believes that such a filing requirement could be a preventative measure to help avoid complaints. In addition, a cost allocation manual will provide useful information in the event a complaint is filed and investigated.

Confidentiality

The confidentiality of information filed by EMCs pursuant to the rule is also an issue raised by the parties. NCEMC recommends that language should be included in the rule to protect the confidentiality of all filings, statements, documents and reports filed or submitted by an EMC pursuant to the rule. While the Public Staff recognizes the sensitive nature of information which would be submitted by the EMCs under the rule, the Public Staff recommends that the EMCs should assert confidentiality on a case-by-case basis when EMCs believe certain information constitutes a trade secret and should be treated as confidential under the Public Records Act. The Commission agrees with the Public Staff and concludes that confidentiality should be asserted on a case-by-case basis under the Public Records Act. This conclusion is generally consistent with the normal practice of the Commission and numerous parties which file sensitive information with the Commission. The Commission believes it is preferable to rule on confidentiality issues as they arise, given the specific facts and circumstances as they then exist, rather than ruling on this issue on a prospective basis in the context of a rulemaking.

Codes of Conduct

The Public Staff's Proposed Rule also includes a requirement that an EMC would file a code of conduct, updated annually. In its comments, NCEMC states that if the Commission decides to require a code of conduct, it proposes that EMCs should be required to file a copy of a code of conduct as adopted by its board of directors, and thereafter, the EMC would file any subsequently adopted changes to that code within a specific period before the effective date of the change. NCEMC submits that this would avoid filing copies of an unchanged code of conduct each year. According to the reply comments, the Public Staff agrees with this proposal by NCEMC. Therefore, the Commission concludes that the rule should require the EMCs to file a code of conduct adopted by the board of the EMC, which would be updated not later than 30 days prior to the effective date of any change.

Report on Transactions

The proposed rules of both the Public Staff and NCEMC include a filing requirement for a report on transactions between EMCs and their separate business entities on a form provided by the Commission. However, the Public Staff's Proposed Rule would require each EMC to file such a report annually, while NCEMC's Proposed Rule would require an EMC to file such a report only after the Commission commences a complaint investigation.

The Public Staff and NCEMC also submitted a proposed transaction report form for approval by the Commission. The proposed transaction report form recommended by each of these parties consists of nine pages, and on most pages, several different items of information are requested. In general, the information requested by each of these proposed forms is quite similar. However, the parties disagree on whether the forms should require EMCs to report information on transfers to EMCs from separate business entities, or upstream transfers, as previously discussed herein.

Therefore, the differences concerning the proposed transaction report are (1) whether the final rule should require such a report annually or only after a complaint investigation has commenced, and (2) whether the report form approved by the Commission should require EMCs to provide information on upstream transfers.

After carefully considering the comments of the parties with respect to the transaction report issue, the Commission agrees with the opinions espoused by the Public Staff in its comments concerning the Commission's role and authority under G.S. 117-18.1. Accordingly, the Commission concludes that the Commission Rule should require EMCs to file an annual report on transactions between EMCs and their separate business entities on a form provided by the Commission. Further, the Commission adopts the report form recommended by the Public Staff, amended to include the changes in language agreed upon by the NCEMC and the Public Staff in their comments. The annual transaction report, in conjunction with the other filing requirements contained in the rule, will enable the Commission and the Public Staff to monitor the cost allocations and transfer pricing for goods and services to and from EMCs that engage in business activities conducted pursuant to the statute. G.S. 117-18.1(a)(3) specifically authorizes the Commission to adopt rules and reporting requirements to enforce this subdivision. Therefore, the statute clearly authorizes the Commission to establish the reporting requirements it needs to fulfill its oversight responsibility. While some parties contend that the annual transaction report is overly burdensome and unnecessary, EMCs which choose to engage in activities permitted by G.S. 117-18.1 must abide by the transfer pricing condition set forth in the statute. The Commission believes that it is not unreasonable to establish annual filing requirements, including the annual transaction report, which constitute a contextual framework designed to require EMCs to demonstrate compliance with the transfer pricing condition. The Commission will rely on the Public Staff to review the annual transaction reports and to take appropriate action should it discover problems.

As to whether the Commission can or should require EMCs to report information on transfers to EMCs from separate business entities, or upstream transfers, the Commission can and should require such information for the following reasons. First, although NCEMC argues against any such reporting requirements based on statutory grounds, the statute also includes the following language: "[s]hould the Utilities Commission, upon complaint showing reasonable grounds for investigation, find after investigation that the charges for those transactions <u>between</u> the (EMC) and the other business entity do not conform. . ." (emphasis added). In addition, this same subdivision of the statute authorizes the Commission and the Public Staff to inspect the books and records of both the EMCs and the other business entities. Given the use of the word "between" in the statute, and the authority granted to inspect both books, the Commission believes that the statute allows the

Commission to examine transactions flowing in either direction. Second, as a practical matter, even if transfers from an EMC to a separate business entity are appropriately priced and recorded, simultaneous or subsequent transfers to an EMC from a separate business entity may need to be examined in some cases in order to be able to enforce the statute.

In summary, the Commission concludes that Commission Rule R19-1, attached hereto as Appendix A, should be adopted and become effective as of the date of this Order. In addition, each EMC should file a statement within 30 days from the date of this Order indicating whether or not it is engaged in separate business activities pursuant to G.S. 117-18.1, and if so, a list of the products or services offered by each of the EMC's separate business entities. Further, each EMC which is engaged in such activities should also file audited financial statements for calendar year 2000, a cost allocation manual, and a code of conduct within 90 days from the date of the Order. Finally, although Rule R19-1 would normally require EMCs to file the annual transaction report by May 1st of each year, given the effective date of this Order, EMCs should file the annual transaction report for calendar year 2000 not later than October 1, 2001.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R19-1, as attached hereto as Appendix A, should be, and the same hereby is, adopted effective on the date of this Order;

2. That the Public Staff is hereby requested to file the transaction report form, amended to conform with the agreed upon changes, within ten (10) days of the date of this Order;

3. That each EMC shall file a statement within thirty (30) days from the date of this Order indicating whether or not it is engaged in separate business activities pursuant to G.S. 117-18.1, and if so, a list of the products or services offered by each of the EMC's separate business entities;

4. That each EMC engaged in separate business activities pursuant to G.S. 117-18.1 shall file audited financial statements for calendar year 2000, a cost allocation manual, and a code of conduct within ninety (90) days from the date of this Order;

5. That each EMC engaged in separate business activities pursuant to G.S. 117-18.1 shall file the annual transaction report for calendar year 2000 no later than October 1, 2001; and

6. That the rulings of the Commission herein are without prejudice to issues which may arise with respect to transactions between public utilities regulated by the Commission under Chapter 62 and their affiliates.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of May, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

je051501.01

APPENDIX A

R19-1. Electric Membership Corporation Reporting Requirements.

(a) *General.* G.S. 117-18.1 allows electric membership corporations (EMCs) to own and operate separate business entities that provide energy services and products, telecommunications services and products, water, and wastewater collection and treatment, subject to certain conditions. One of those conditions is that the separate business entity fully compensate the EMC for the use of personnel, services, equipment, or tangible and intangible property of the EMC at the greater of a competitive price or the EMC's fully distributed costs. The Utilities Commission is empowered, upon complaint, to direct the EMC to adjust charges that do not comply with this condition and, if the EMC does not comply, to direct the EMC to divest its interest in the other business entity. To enforce G.S. 117-18.1(a)(3), the Commission, the Commission Staff, and the Public Staff are authorized to inspect the books and records of such other business entities and the EMCs, and the Commission is authorized to adopt rules and reporting requirements. G.S. 62-53 provides that in addition to any other authority granted in this Chapter, the Commission has the authority to regulate EMCs as provided in G.S. 117-18.1.

(b) *Applicability.* This rule is applicable to each EMC providing electric service in North Carolina.

(c) *Reporting Requirements by Electric Membership Corporations.* Each EMC that conducts activities pursuant to G.S. 117-18.1 shall file with the Commission the following:

(1) a copy of its audited financial statements, on an annual basis;
(2) a cost allocation manual, updated within 30 days of any significant change in cost allocation methodologies;
(3) a code of conduct adopted by the board of directors of the EMC, updated not later than 30 days prior to the effective date of any change; and
(4) an annual report on transactions between the EMC and separate business entities by which the EMC conducts activities permitted by G.S. 117-18.1, on a form prescribed by the Commission and available through the Chief Clerk of the Commission.

The financial statements and annual reports on transactions shall each cover an annual reporting period of January 1st to December 31st and shall be filed as soon as possible after the close of the calendar year but in no event later than May 1st of the year following the calendar year covered by financial statements and annual reports. The initial cost allocation manual and code of conduct shall be filed no later than 90 days after an EMC conducts its first activity permitted by G.S. 117-18.1. The financial statements and annual reports shall be verified by the oath of the chief executive officer of the EMC in accordance with the requirements of G.S. 62-53.

(d) *Confidentiality of Information Submitted Pursuant to Rule.* Any claim of confidentiality with regard to information submitted pursuant to this Rule shall be made with specificity by the EMC and shall, if necessary, be determined by the Commission in accordance with Chapter 132 of the North Carolina General Statutes, the Public Records Act. Consistent with G.S. 132-1.2, any claim of confidentiality made by an EMC shall relate to "trade secrets" as defined in G.S. 66-152(3) and shall be explicit; i.e., every page for which such a claim is asserted shall be clearly stamped "CONFIDENTIAL" at the time of the filing. In the event an interested person shall desire access to information claimed by the affected EMC to constitute a trade secret, the person desiring such access shall file a letter with the Chief Clerk of the Commission, with a copy to the affected EMC, requesting a determination as to the extent to which the information in question is actually protected from public disclosure under the Public Records Act.

(e) *Electric Membership Corporations That Do Not Conduct Activities Permitted by G.S. 117-18.1.* An EMC that does not conduct activities permitted by G.S. 117-18.1 during a calendar year shall only be required to file an annual statement to that effect, no later than May 1st of the following calendar year.

DOCKET NO. E-100, SUB 91

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Revise Commission	)	ORDER AMENDING
Rule R8-27, Uniform System of Accounts	)	RULE R8-27

BY THE COMMISSION: On February 20, 2001, the Commission issued an Order Instituting Rulemaking Proceeding to receive comments on the appropriateness of amending Commission Rule R8-27, Uniform System of Accounts (USOA) for electric utilities. Such Order came about as a result of The National Association of Regulatory Utility Commissioners (NARUC), assembled at its 111th Annual Convention in San Antonio, Texas, adopting a resolution to the effect that it would no longer maintain the NARUC USOA for electric utilities. As a part of that resolution, NARUC encouraged state utility commissions to adopt the Federal Energy Regulatory Commission (FERC) USOA for electric utilities, with appropriate modifications to meet state-specific requirements where necessary. Said Order allowed all interested persons the opportunity to file comments and reply comments on the comments of other parties. However, no reply comments were filed by any party.

COMMENTS

Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene and fully participate in the above-captioned proceeding and to otherwise exercise all statutory rights provided to intervenors under North Carolina law. On March 19, 2001, the Commission issued an Order granting petition to intervene as requested. CUCA did not file comments or reply comments with respect to this proceeding.

Carolina Industrial Groups For Fair Utility Rates I & II (CIGFUR) filed a joint petition to intervene in this proceeding. The Commission issued an Order on March 27, 2001, allowing CIGFUR to intervene. CIGFUR did not file comments or reply comments in this proceeding.

Carolina Power & Light Company (CP&L) filed comments regarding this proceeding. CP&L stated in its filing that it supports the adoption of the FERC USOA for electric utilities, with appropriate modifications to meet state-specific requirements where necessary.

The Public Staff filed comments and recommendations in this proceeding. The Public Staff stated in its filing that it believes that with certain exceptions and conditions the FERC USOA for electric utilities is an acceptable alternative to the NARUC USOA. However, the Public Staff commented that the following safeguards should be a part of any revised Rule R8-27 or a part of the Commission's Order adopting the revised Rule:

1. The adoption of the FERC USOA for electric utilities should not indicate that the Commission defers to the FERC in any way on questions of the appropriate accounting for any given transaction. The content of the FERC USOA should be adopted; however, the Commission should retain sole authority over the application of that content to the books and records maintained by the utilities for purposes of North Carolina retail jurisdictional accounting and reporting.

2. All accounting, ratemaking, and other orders previously issued by the Commission should remain in effect, even if those orders conflicted with the FERC USOA, and future such orders would supersede the provisions of the FERC USOA for North Carolina retail accounting, ratemaking, and other regulatory purposes.

3. Within 90 days of the date of this Order, Duke Energy Corporation (including Nantahala Power and Light), CP&L, and Dominion North Carolina Power should each file a report detailing any and all changes in their North Carolina retail accounting and reporting practices resulting from this adoption.

The Public Staff further stated in its comments that these safeguards are intended to burden the utilities as little as possible while still ensuring that the Commission is kept adequately informed so as to be able to effectively regulate the electric utilities of this State. The Public Staff is of the opinion that desired information over and above that required by the Rule can be obtained as necessary on a case-by-case basis by order of the Commission and/or data requests of the Public Staff or the Commission Staff.

The Public Staff recommended that its proposed Rule R8-27, be adopted by the Commission and replace the existing Rule R8-27 in its entirety.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the revised Rule R8-27, as proposed by the Public Staff, with minor modifications should be adopted. The above-stated safeguards as noted by the Public Staff will ensure that the Commission is kept adequately informed in its efforts to make effective regulatory decisions with respect to the electric industry. The Commission believes that the implementation of such safeguards will not unduly burden the electric utilities in any way. Further, the Commission believes that Duke Energy Corporation (including Nantahala Power and Light), CP&L, and Dominion North Carolina Power should each file a report detailing any and all changes in their North Carolina retail accounting and reporting practices resulting from this adoption within 90 days of the effective date of the revised Rule R8-27.

The Commission also agrees with the Public Staff regarding additional information. If such a need arises, it shall be addressed on a case-by-case basis by order of the Commission and or data requests of the Public Staff or Commission Staff.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R8-27 of the Commission's Rules and Regulations is hereby revised as set forth in Appendix A attached hereto and is hereby, as revised, incorporated into said rules and regulations.

2. That Duke Energy Corporation (including Nantahala Power and Light), CP&L, and Dominion North Carolina Power shall each file on March 31, 2002, a report detailing any and all changes in their North Carolina retail accounting and reporting practices resulting from this adoption.

3. That the Chief Clerk shall mail a copy of this Order to all the electric companies operating in North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of September, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb090501.01

APPENDIX A

Rule R8-27. Uniform system of accounts.€

(a) For utilities with annual accounting and reporting periods based on the calendar year, effective January 1, 2002, and for utilities with fiscal year accounting and reporting periods, effective with fiscal years beginning in 2002, 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, and as revised periodically, is hereby adopted by this Commission as its accounting rules for electric utilities and is prescribed for the use of all electric utilities under the jurisdiction of the North Carolina Utilities Commission, subject to the following exceptions and conditions unless otherwise ordered by the Commission: €

(1) All orders and practices of the Commission in effect as of the effective date of this Rule with any accounting impacts that conflict with provisions of the Uniform System of Accounts shall remain in effect, and future such orders and practices with such impacts shall supersede the provisions of the Uniform System of Accounts for North Carolina retail jurisdictional purposes.

(2) The electric utilities under the jurisdiction of the Commission must apply to the Commission for any North Carolina retail jurisdictional use of the following accounts:

a. Account 182.1 - Extraordinary Property Losses.
b. Account 182.2 - Unrecovered Plant and Regulatory Study Costs.
c. Account 182.3 - Other Regulatory Assets.
d. Account 254 - Other Regulatory Liabilities.
e. Account 407 - Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.
f. Account 407.3 - Regulatory Debits.
g. Account 407.4 - Regulatory Credits.

(b) Each electric utility subject to this Rule shall file the following with the Commission: €

(1) In the case of utility filings and other correspondence with the FERC or its staff, on and after the effective date of this Rule, regarding the utility's accounting practices or the Uniform System of Accounts, including but not limited to requests for accounting guidance and or approval of accounting entries, the portion of the initial filing or correspondence by the utility relating to said accounting practices or the Uniform System of Accounts, and the final disposition of the matter.

(2) In the case of other changes in the utility's accounting practices prompted by FERC orders, directives, or correspondence, a written explanation of the change in practice, along with relevant supporting documentation.

(3) In the case of the regular periodic or any special compliance audits performed on and after the effective date of this Rule by the FERC or its staff, notification of the commencement of the audit and a copy of the final audit report.

(c) The accounting treatment to be used for contributions in aid of construction is as follows:

(1) Contributions in aid of construction received before the effective date of this Rule are to be accounted for in the manner prescribed by the Commission in Docket No. E-100, Sub 18.

(2) Contributions in aid of construction received on and after the effective date of this Rule are to be accounted for in the manner prescribed by the Uniform System of Accounts adopted herein.

(d) The following classification system is hereby adopted:

Class A: Electric utilities having annual electric operating revenues of $2,500,000 or more.

Class B: Electric utilities having annual electric operating revenues of $1,000,000 or more but less than $2,500,000.

Class C: Electric utilities having annual electric operating revenues of $150,000 or more but less than $1,000,000.

Class D: Electric utilities having annual electric operating revenues of $25,000 or more but less than $150,000.

(e) Electric utilities with annual gross operating revenues of less than $25,000 shall be exempt from the provisions of this Rule until the average of their annual gross revenues, for a period of three consecutive years, shall exceed $25,000. Electric utilities exceeding the $25,000 threshold but falling below the minimum threshold of 10,000 megawatthours of annual sales included in the FERC Uniform System of Accounts shall nevertheless utilize the FERC Uniform System of Accounts as specified for Nonmajor utilities.€

(NCUC Docket No. E-100, Sub 18, 5/24/74; NCUC Docket No. E-100, Sub 91, 9/5/01.)

DOCKET NO. G-100, SUB 58

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Implement G.S. 62-133.4	)	ORDER AMENDING
Which Authorizes Gas Cost Adjustment Proceedings	)	RULE R1-17(k)(6)(a) and (b)
for Natural Gas Local Distribution Companies	)	TO INCLUDE TOCCOA

BY THE COMMISSION: G.S. 62-133.4(c) requires each natural gas local distribution company (LDC) to submit data annually concerning its cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes for an historical 12-month test period. The Commission is then required, upon notice and hearing, to compare the LDC's prudently incurred costs with costs recovered from its customers during the test period. Subsection (6)(a) of Commission Rule R1-17(k) specifies the annual test period and filing date for each LDC in connection with the annual gas cost review required by G.S. 62-133.4(c). Subsection (6)(b) specifies the schedule of public hearings for each LDC.

Since this rule was adopted, the Commission has granted a certificate of public convenience and necessity to Toccoa Natural Gas (Toccoa) to operate as a LDC in North Carolina. On June 14, 2001, the Commission issued an Order authorizing purchased gas adjustment procedures and an annual prudency review for Toccoa. The procedures provide for an annual prudency review based on a test period ending June 30th of each year and further provided that Toccoa shall file its first review proceeding for the period ending June 30, 2002.

The Commission, on its own motion, finds good cause to amend Rule R1-17(k)(6)(a) and (b) as shown on Attachment A to include Toccoa.

IT IS, THEREFORE, ORDERED that the amendments to Rule R1-17(k)(6)(a) and (b) shown on Attachment A are adopted.

ISSUED BY ORDER OF THE COMMISSION.
This the 2nd day of September, 2001

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg100101.02

ATTACHMENT A

Rule 1-17. Filing of increased rates; application for authority to adjust rates.

.

(k) Procedure for Rate Adjustments Under G.S. 62-133.4.

.

(6) Annual Review.

(a) Annual Test Periods and Filing Dates. Each LDC shall file and submit to the Commission the information required in Section (k)(6)(c) for an historical 12-month test period. This information shall by filed by Toccoa Natural Gas on or before September 1 of each year based on a test period ended June 30. This information shall be filed by Frontier Energy, LLC, on or before December 1 of each year based on a test period ended September 30. This information shall be filed by North Carolina Natural Gas Corporation on or before February 1 of each year based on a test period ended October 31. This information shall be filed by NUI North Carolina Gas on or before July 1 of each year based on a test period ended April 30. This information shall be filed by Piedmont Natural Gas Company, Inc., on or before August 1 of each year based on a test period ended May 31. This information shall be filed by Public Service Company of North Carolina, Inc., on or before June 1 of each year based on a test period ended March 31.

(b) Public Hearings. The Commission shall schedule an annual public hearing pursuant to G.S. 62-133.4(c) in order to compare each LDC's prudently incurred Gas Costs with Gas Costs recovered from all its customers that it served during the test period. The public hearing for Toccoa Natural Gas shall be on the first Wednesday of November. The public hearing for Frontier Energy, LLC, shall be on the first Tuesday of March. The public hearing for North Carolina Natural Gas Corporation shall be on the second Tuesday of April. The public hearing for NUI North Carolina Gas shall be on the first Tuesday of September. The public hearing for Piedmont Natural Gas Company, Inc., shall be on the first Tuesday of October. The public hearing for Public Service Company of North Carolina, Inc., shall be on the second Tuesday of August. The Commission, on its own motion or the motion of any interested party, may change the date for the public hearing and/or consolidate the hearing required by this section with any other docket(s) pending before the Commission with respect to the affected LDC.

DOCKET NO. G-100, SUB 83

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Rulemaking Proceeding to Revise Commission	)	ORDER AMENDING
Rule R6-70, Uniform System of Accounts	)	RULE R6-70

BY THE COMMISSION: On September 6, 2001, the Commission issued an Order Proposing Amendment of Commission Rule R6-70, Uniform System of Accounts (USOA) for natural gas utilities. Such Order came about as a result of The National Association of Regulatory Utility Commissioners (NARUC), assembled at its 111th Annual Convention in San Antonio, Texas, adopting a resolution to the effect that it would no longer maintain the NARUC USOA for natural gas utilities. As a part of that resolution, NARUC encouraged state utility commissions to adopt the Federal Energy Regulatory Commission (FERC) USOA for natural gas utilities, with appropriate modifications to meet state-specific requirements where necessary.

In that Order, the Commission proposed that Rule R6-70 of the Commission's Rules and Regulations was to be revised as set forth in Appendix A, attached thereto. All affected parties were requested to file any proposed changes to the proposed Rule within 15 days of the date of such Order. If no party filed comments or proposed changes within said time period, the Commission provided that a further order would be issued adopting the proposed Rule.

On September 21, 2001, The City of Toccoa, Georgia, operating in North Carolina as Toccoa Natural Gas (TNG), filed a letter requesting an exemption from the proposed amendment of Rule R6-70. TNG stated in its request that as a small municipal distributor, it would find it extremely cumbersome and cost prohibitive to comply with the proposed amendment, and that it does not have the flexibility in its computer software to easily or inexpensively modify the accounting system. TNG serves approximately 389 customers in Macon County, North Carolina.

TNG is exempted in the State of Georgia and is not required to adhere to either NARUC or FERC USOA, but is required by the State of Georgia to use the revised Governmental Accounting Standards Board (GASB) Statement #34; effective March 23, 2001. The Public Staff has indicated that it does not object to TNG being exempted from the requirements set out in the proposed Rule R6-70 and does not anticipate any difficulty in monitoring and reviewing TNG's records which are in compliance with GASB Statement #34.

Based on the foregoing, Commission concludes that the proposed amendment of Rule R6-70 should be adopted and should replace the existing Rule R6-70 in its entirety, as stated in Appendix A, attached hereto. The Commission further concludes that TNG should be exempted from the requirements of said Rule.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R6-70 of the Commission's Rules and Regulations is hereby revised as set forth in Appendix A attached hereto and is hereby, as revised, incorporated into said rules and regulations.

2. That Piedmont Natural Gas Company, Inc. shall be allowed to keep the account title and the account number in separate data fields in its database.

3. That the Commission shall adopt FERC's interpretation of the FERC USOA until such time as a particular interpretation is addressed and/or otherwise changed by the Commission on a prospective basis.

4. That the use of the local distribution company's (LDC) overall rate of return on investment, as authorized in each respective LDC's last general rate case proceeding, shall continue to be used in the computation of allowance for funds used during construction.

5. That all natural gas utilities operating under the Commission's jurisdiction shall use the FERC Class A, USOA, except Toccoa Natural Gas.

6. That the Chief Clerk shall mail a copy of this Order to all the natural gas companies operating in North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb101101.01

APPENDIX A

Rule R6-70. Uniform system of accounts.€

For utilities with annual accounting and reporting periods based on the calendar year, effective January 1, 2002, and for utilities with fiscal year accounting and reporting periods, effective with fiscal years beginning in 2002, the Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, as currently embodied in the United States Code of Federal Regulations, Title 18, Part 201, and as revised periodically, is hereby adopted by this Commission as its accounting rules for natural gas utilities and is prescribed for the use of all natural gas utilities under the jurisdiction of the North Carolina Utilities Commission, subject to the following exceptions and conditions unless otherwise ordered by the Commission: €

GENERAL ORDERS - NATURAL GAS

(1) All orders and practices of the Commission in effect as of the effective date of this Rule with any accounting impacts that conflict with provisions of the Uniform System of Accounts shall remain in effect, and future such orders and practices with such impacts shall supersede the provisions of the Uniform System of Accounts for North Carolina retail jurisdictional purposes.

(2) All references to federal statutes, federal regulations, and other federal documents are to be ignored or deleted where they are not applicable to the jurisdiction exercised by this Commission.

(3) Instead of natural gas companies being divided into Class A, Class B, Class C, and Class D categories, all companies shall be treated as Class A companies.

DOCKET NO. P-100, SUB 72

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Investigation to Consider Whether Competitive Long Distance Service Should Be Allowed in North Carolina and What Rules and Regulations Should be Applicable	))))	ORDER CLARIFYING DEFINITION OF FACILITIES-BASED INTEREXCHANGE CARRIERS

BY THE COMMISSION: On July 13, 2000, the Association for Local Telecommunications Services (ALTS) filed Motion to Clarify Distinction Between IXC Facilities-Based Carrier and Switched Reseller. ALTS, which is a trade association of competing local providers (many of whom have both local and interexchange authority) noted that on December 23, 1998, the Commission had issued its Order Relaxing Regulation of Resellers wherein it adopted the Public Staff's recommendation that both switched and switchless resellers should become subject to the same relaxed application process.

In that Order, the Commission defined facilities-based carriers as those that "own and operate transmission facilities which may be used alone to provide nonswitched services or in conjunction with switching equipment to create a long distance network for the provision of switched services to individual customers as well as resellers. Resellers were defined as including "(1) providers who do not own any network and switching facilities and only resell (switchless resellers) and (2) providers who own switching equipment but not transmission facilities and connect the necessary transmission facilities, which are obtained from facilities-based carries, to the switch in order to produce a complete switched service (switched resellers)."

ALTS stated that neither of these definitions addressed carriers who own a switch by leasing transmission facilities. The Reseller Application includes as the first question on page 2: "Does the Applicant own, lease or operate transmission facilities (whether in North Carolina or not) which will be used to complete intrastate calls in North Carolina?" ALTS contended that the form thus appears to be inconsistent with the Commission's Order because it expands the definition of facilities-based carrier to include carriers which lease transmission facilities. It was ALTS understanding that the Public Staff interprets the term switched reseller to include only carriers purchasing tariffed transmission services.

ALTS noted that it members have applied for reseller authority on the basis of the Commission's definition of reseller in the Order, although in many cases ALTS members propose to lease facilities or capacity from other carriers. Under the Order ALTS members and others similarly situated are resellers, but the Reseller Application suggests that such carriers may not be resellers.

ALTS requested that the Commission that its definition of "facilities-based carriers" includes only those carriers which own transmission facilities. ALTS also requested that the Commission revise it Reseller Application to omit the words "lease or operate" from the first question on page 2 to be consistent with the Order.

Public Staff Comments

The Public Staff stated that the question at issue is a modification of question that was part of the reseller application when the Commission first relaxed the application for switchless resellers in its January 10, 1996, Order in this docket. In that Order, the Commission noted that the Public Staff described switchless resellers as IXCs that own no switching or transmission facilities, but rather simply provide service to end users by purchasing a tariffed service from an underlying carrier which provides all the switching and transmission facilities necessary. Thus, the original question dealt with the resellers use of switching facilities. Subsequent further relaxation of requirements led to the question being modified to address the IXC's use of transmission facilities. The only wording change was from "switching" to "transmission." Since the Public Staff believes that carriers leasing transmission facilities from another carrier will also be operating them, the Public Staff sees little, if any, difference between the description of facilities-based IXCs in the Order and the question on the reseller application.

The Public Staff interprets the phrase "own, operate, or lease transmission facilities" to include all situations other than those where the transmission facilities are used by an IXC through the purchase of a tariffed offering. The Public Staff believes that <u>control</u> over transmission facilities is the clearest and most meaningful basis for distinguishing between facilities-based IXCs and switched resellers. Under this distinction, carriers that <u>lease</u> facilities from wholesale providers are treated the same as carriers that <u>own</u> their own facilities. In both cases, the carriers have considerable opportunity to influence prices and service quality, while resellers of tariffed services have limited or no ability to do either.

Therefore, the Public Staff requested the Commission to clarify its December 23, 1998, Order by defining facilities-based IXCs as carriers that own, operate, or lease transmission facilities which are used in the provision of intrastate long distance service in North Carolina.

Whereupon, the Commission reaches the following

Conclusions

After careful consideration the Commission concludes that it should adopt the clarification suggested by the Public Staff--namely, that the December 23, 1998, Order be clarified by defining facilities-based IXCs as carriers that own, operate, or lease transmission facilities which are used in the provision of intrastate long distance service in North Carolina. While this is broader than that which ALTs requests as clarification, it appears to comport more closely with the empirical reality that the Public Staff has identified--that is, that control over the transmission facilities is the appropriate criterion for distinguishing between facilities-based and switched resellers because of opportunity to influence prices and service and that those that lease transmission facilities are also operating them.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

pb030601.04

DOCKET NO. P-100, SUB 99

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Quality of Service Objectives for Local	)	ORDER AMENDING RULE,
Exchange Telephone Companies	)	FORMING INDUSTRY TASK
	)	FORCE, REQUESTING
	)	INDEPENDENT EVALUATION
	)	BY THE PUBLIC STAFF, AND
	)	REVISING REPORTING
	)	REQUIREMENT

BY THE COMMISSION: By Order dated September 20, 2000, the Commission revised Rule R9-8 to incorporate a new subsection concerning reporting on the service objectives. In said Order, the Commission required all incumbent local exchange companies (ILECs) and all competing local providers (CLPs) actually providing service to customers in North Carolina to file with the Commission by November 15, 2000, clear, detailed explanations of their measurement procedures for each service objective outlined in Rule R9-8. The Commission noted that it would need the information to evaluate and understand how each company is measuring the results to be reported in its monthly service objective report. Further in the September 20, 2000 Order, the Commission incorporated a reporting requirement wherein each local exchange telephone company would be required to file a report on the 20th day of each month beginning on January 20, 2001 with the Chief Clerk of the Commission detailing the results of its compliance with each of the uniform service objectives set forth in Rule R9-8.

On October 10, 2000, Association of Communications Enterprises (ASCENT), Birch Telecom of the South, Inc., Business Telecom, Inc., ConnectSouth Communications of North Carolina, Inc., DIECA Communications, Inc. d/b/a Covad Communications Company, ICG Telecom Group, Inc., ITC^DeltaCom Communications, Inc. d/b/a ITC^DeltaCom, MCImetro Access Transmission Services, LLC, NewSouth Communications Corp., North Carolina Cable Telecommunications Association, Time Warner Telecom of North Carolina, L.P., US LEC of North Carolina, Inc., and XO North Carolina, Inc., formerly NEXTLINK North Carolina, Inc. (collectively the Joint Movants) filed a Joint Motion to Reconsider or Clarify Order Revising Rule R9-8 to Adopt Reporting Requirement and Establishing Semiannual Service Quality Presentations and Joint Motion to Stay Order During Pendency of Reconsideration and/or Clarification. By their Motion, the Joint Movants requested that the Commission issue an order either (1) exempting CLPs from the new reporting and presentation requirements of revised Rule R9-8 and the September 20, 2000 Order or (2) clarifying that the revised rule and requirements of the September 20, 2000 Order apply to CLPs only insofar as they are offering services to residential customers.

By Order dated October 12, 2000, the Chair requested interested Parties to file comments on the Joint Movants' Motion by no later than October 27, 2000.

On November 29, 2000, the Commission issued an Order Denying the Motion for Reconsideration but Clarifying the September 20, 2000 Order. In the Order, the Commission stated that after reviewing all of the comments received on the Joint Movants' Motion and examining the information available from other states (specifically from Tennessee, Florida, and Virginia), the Commission believed that it was reasonable and appropriate to clarify the September 20, 2000 Order to include only those companies which provide basic local residential and business exchange service to customers in North Carolina. The Commission noted that it has seen some evidence indicating that competition is developing in the business markets in North Carolina. However, the Commission further stated that it believes that there has been less evidence that the residential local telecommunications market is competitive to any significant degree. Therefore, the Commission noted that it was reasonable to continue to monitor the service quality for both basic local residential and business exchange service until competition fully develops without question in those markets. The Commission denied the Joint Movants' Motion for Reconsideration and clarified that its September 20, 2000 Order on reporting requirements applies only to those carriers providing basic local residential or business exchange service. The Commission further amended its September 20, 2000 Order revising Rule R9-8 as follows:

> (d) Reporting Requirement - Each local exchange telephone company <u>actually providing basic local residential and/or business exchange service to customers in North Carolina</u> shall file an original and five (5) copies of a report each month with the Chief Clerk of the Commission detailing the results of its compliance with each of the uniform service objectives set forth in this rule. Each company shall report its performance result for each objective for its state service area as a whole and whenever possible, by exchange or district. This report shall be filed no later than twenty (20) days after the last day of the month covered by the report. **NOTE:** The inserted clarifying language is underlined.

The Commission also altered the procedural schedule established in the docket and ordered the Companies to file detailed explanations on the standards by December 29, 2000 and postponed the reporting until March 20, 2001 and monthly on the 20th thereafter.

The Commission granted various Motions for extensions of time on the filing of the detailed explanations of the service objectives.

ILEC COALITION'S FILING

On December 21, 2000, BellSouth Telecommunications, Inc. (BellSouth), Carolina Telephone and Telegraph Company and Central Telephone Company (collectively Sprint), and Verizon South, Inc. (Verizon) (collectively the ILEC Coalition), filed their detailed explanations of the measurement procedures for the service objectives set forth in Rule R9-8. Additionally, the ILEC Coalition formally requested that the Commission create an Industry Task Force to consider revisions to Rule R9-8 in light of today's telecommunications environment.

The ILEC Coalition noted that the service objectives in Rule R9-8 were established almost thirteen years ago on December 20, 1988. The ILEC Coalition further noted that when the Commission issued its Order codifying Rule R9-8, it explicitly recognized that future circumstances could warrant changes in or exceptions to its newly codified standards by stating, "This rule is not meant, in anyway, to preclude flexibility in considering future circumstances that may justify changes in or exceptions to these quality of service objectives." Therefore, the ILEC Coalition opined, it is time for the Commission and the industry to review the service objectives set forth in Rule R9-8 in light of the world of telephony in 2001.

The ILEC Coalition stated that the telecommunications world in 2001 hardly resembles the world in which the service objectives in Rule R9-8 were developed. The ILEC Coalition argued that at the most basic level, technological advancements alone have simply eliminated the need for many of the Rule R9-8 objectives. Further, the ILEC Coalition argued, the answer time requirements reflect an era that has long passed and do not accurately reflect a consumer's level of satisfaction with his or her local service provider. The ILEC Coalition noted that the length of time that a customer must speak with a service representative to order new service or to seek an explanation of a telephone bill has increased dramatically since Rule R9-8 was promulgated.

Further, the ILEC Coalition argued that Rule R9-8 was formulated in an era when no competition existed within the local exchange market. The ILEC Coalition asserted that it is undisputed that local exchange competition not only exists today but is growing at an ever increasing pace. The ILEC Coalition argued that it is axiomatic that as competition emerges in an industry, the need for regulation of that industry decreases.

The ILEC Coalition noted the open Federal Communications Commission (FCC) Proposed Rulemaking docket wherein the FCC proposes to "eliminate the bulk of the existing service quality reporting requirements, which no longer make sense in today's marketplace."

The ILEC Coalition suggested that an analysis similar to that proposed by the FCC should be conducted by the Commission of its service quality objectives. The ILEC Coalition requested that the Commission order the formation of an Industry Task Force to study possible revisions to, additions to, and/or elimination of certain Rule R9-8 service objectives. The ILEC Coalition stated that for the ultimate list of service objectives, the Industry Task Force could suggest standards which would guarantee customers acceptable service levels as competition becomes more pervasive. The ILEC Coalition stated that for the service objectives that the Industry Task Force does not recommend eliminating, the group could suggest new, minimum standards to use as competition becomes more pervasive. The ILEC Coalition stated that after competition becomes more pervasive, competition will set standards of excellence with the Commission establishing only minimum standards for the industry as a whole.

OTHER FILINGS

ALLIANCE: The Alliance of North Carolina Independent Telephone Companies (the ALLIANCE)[1] filed its response on December 27, 2000. The ALLIANCE filed the explanation of each ALLIANCE member company's respective service quality measurement procedures and comments of The ALLIANCE relating to those procedures and the ILEC Coalition's request for establishment of an Industry Task Force. The ALLIANCE stated that it supports the ILEC Coalition's Request and noted that The ALLIANCE has previously made such a request before the Commission in this docket.

ALLTEL CAROLINA: On December 29, 2000, ALLTEL Carolina, Inc. (ALLTEL Carolina) filed its detailed explanations of its measurement procedures and comments on the ILEC Coalition's Request. ALLTEL Carolina stated that it agrees with the ILEC Coalition's Request for the establishment of an Industry Task Force.

ALLTEL COMMUNICATIONS: On December 29, 2000, ALLTEL Communications, Inc. filed its detailed explanations of its measurement procedures and comments on the ILEC Coalition's Request. ALLTEL stated that it agrees with the ILEC Coalition's Request for the establishment of an Industry Task Force.

MCIm: On January 4, 2001, MCImetro Access Transmission Services, Inc. (MCIm) filed its detailed explanations of its measurement procedures and comments on the ILEC Coalition's Request. MCIm stated that it supports the ILEC Coalition's Request.

PINEVILLE: On December 29, 2000, Pineville Telephone Company (Pineville) filed its detailed explanations of its measurement procedures and comments on the ILEC Coalition's Request. Pineville stated that it agrees with the ILEC Coalition's Request for the establishment of an Industry Task Force.

SECCA: On January 4, 2001, the Southeastern Competitive Carriers Association (SECCA) filed a letter supporting the ILEC Coalition's Request for the creation of an Industry Task Force to consider

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[1] The ALLIANCE consists of the following independent North Carolina local telephone companies: Citizens Telephone Company, The Concord Telephone Company, Ellerbe Telephone Company, LEXCOM Telephone Company, MEBTEL Communications, North State Telephone Company, and Randolph Telephone Company.

revisions to Rule R9-8. SECCA stated that it believes that the circumstances described in the Request warrant a review of the Rule.

TDS COMPANIES: On December 29, 2000, Barnardsville Telephone Company, Saluda Mountain Telephone Company, and Service Telephone Company (the TDS Companies) filed their detailed explanations of their measurement procedures and comments on the ILEC Coalition's Request. The TDS Companies stated that they agree with the ILEC Coalition's Request for the establishment of an Industry Task Force.

DETAILED EXPLANATIONS

The following companies not previously referenced filed detailed explanations of their measurement procedures for each of the service objectives outlined in Rule R9-8:

TeleConex, Inc.
Springboard Telecom, L.L.C.
Teligent Services, Inc.
Time Warner Telecom of North Carolina, L.P.
LTS of Rocky Mount, L.L.C.
NewSouth Communications Corporation
Adelphia Business Solutions Operations, Inc.
Budget Phone, Inc.
Madison River Communications, L.L.C.
NOW Communications, Inc.
CTC Exchange Services, Inc.
Intermedia Communications, Inc.
AT&T and TCG
US LEC of North Carolina
TriVergent Communications
Consumers Telephone and Telecom, Inc.
ITC^DeltaCom
Choctaw Communications, Inc., d/b/a Smoke Signal Communications

The following companies filed letters with the Commission stating that they were not providing service in the State and therefore have no service to measure:

CCCNC, Inc., d/b/a Connect!
SBC Telecom
Advanced TelCom, Inc.
Pathnet Operating, Inc.
BroadRiver Communications Corporation
BellSouth BSE, Inc.
GSIwave.com, Inc.
Level 3 Communications, L.L.C.
ComScape Communications, Inc.
Network Plus

United Communications Hub, Inc. (UC HUB)
LecStar Telecom, Inc.
LineDrive Communications, Inc.
Mpower Communications Corporation
Excel Telecommunications, Inc.
Caronet, Inc.

The following companies filed responses indicating that they operate as resellers and do not have direct control over all of the objectives; for those objectives they do have control over, the companies provided an explanation of their measurement procedures for the objective:

PaeTec Communications, Inc.
Access Integrated Networks, Inc.
@ Communications, Inc.
AmeriMex Communications Corp.
Crystal Clear Connections, Inc.
New East Telephony, Inc.
OnePoint Communications
EZ Talk Communications, L.L.C.

The following remaining filings have been made in this docket:

- ICG Telecom Group, Inc. requested an extension of time to file its detailed explanations until early January 2001. ICG never made a filing of its detailed explanations.

- DSLnet Communications, Inc. filed its service objectives report and noted that it only offers xDSL services.

- PaeTec Communications, Inc. filed its service objectives report with results for the month of December 2000.

- Budget Phone filed its service objectives report with results for September 2000.

- Talk.com Hold Company, d/b/a Tel-Save, Inc. filed its service objectives report with results for February 2001.

PUBLIC STAFF'S COMMENTS

On March 1, 2001, the Public Staff filed its comments on the description filings of the ILECs and CLPs and on the ILEC Coalition's Request for the Commission to establish an Industry Task Force.

EXPLANATION FILINGS:

The Public Staff stated that most ILECs and CLPs submitted explanations for the last eleven objectives in Rule R9-8, with the exception of Regrade Application Held Orders Not Completed Within 30 Days. The Public Staff noted that the explanations generally contain insufficient detail to enable the Public Staff to determine how the measurements were actually performed. The Public Staff maintained that the vague explanations raise a host of questions about actually how the company would measure certain items.

The Public Staff stated that it believes that interested parties should be able to easily understand the specific service quality inputs a company uses and how the company operates on these inputs to generate the monthly statistics reported to the Commission. The Public Staff maintained that if there are company practices that further define the measurement procedures used, they should also be furnished to the Commission and Public Staff for review, as ALLTEL Carolina did with its December 29, 2000 response in this docket.

The Public Staff recommended that the Commission order the ILECs and CLPs to revise and upgrade their detailed explanations of their measurement procedures for the last twelve objectives in Rule R9-8 with the exception of the Regrade Application Held Orders Not Completed Within 30 Days objective, as necessary to comply with the directive of the Commission, and to furnish the revisions to the Commission no later than March 31, 2001.

The Public Staff further noted that most of the ILECs and CLPs addressed the first seven objectives of Rule 9-8 by simply reporting that they do not measure those objectives. The Public Staff maintained that although the companies never stated that it is impossible for them to measure these objectives, the Public Staff does not recommend that they be required to do so at this time. The Public Staff recommended that the Commission refrain from requiring the companies to develop or initiate procedures for measuring and reporting these seven objectives in order to give an Industry Task Force the opportunity to consider and report on the objectives. These seven objectives are as follows:

(1) Intraoffice completion rate
(2) Interoffice completion rate
(3) Direct distance dialing completion rate
(4) EAS transmission loss
(5) Intrastate toll transmission loss
(6) EAS trunk noise
(7) Intrastate toll trunk noise

The Public Staff stated that with respect to the Regrade Application Held Orders Not Completed Within 30 Days objective, the Public Staff recognizes that there are no ILECs or CLPs operating multiparty service in North Carolina today. Therefore, the Public Staff recommended that the Commission delete that service objective from Rule R9-8.

The Public Staff further recommended that the Commission continue to require all ILECs and CLPs subject to Rule R9-8 to adhere to the reporting schedule established in the November 29, 2000

Order, but recommended that the reporting requirement be limited, for the time being, to the following ten objectives in Rule R9-8:

(1) Operator "O" answertime
(2) Directory assistance answertime
(3) Business office answertime
(4) Repair service answertime
(5) Initial customer trouble reports (excluding repeat reports)
(6) Repeat reports
(7) Out-of-service troubles cleared within 24 hours
(8) Regular service orders completed within 5 working days
(9) New service installation appointments not met for Company reasons
(10) New service held orders not completed within 30 days

REQUEST FOR INDUSTRY TASK FORCE:

The Public Staff commented that the ILEC Coalition has raised some interesting points in its request for the formation of an Industry Task Force that warrant further study. The Public Staff stated that it is not opposed to the Commission establishing an Industry Task Force to study the service quality objectives. The Public Staff did, however, recommend that the Commission only allow the Task Force approximately six months to meet, develop recommendations, and submit a report on its recommendations to the Commission. The Public Staff also proposed that the Commission require the Task Force to devise and propose to the Commission a uniform measurement procedure for each of the 17 service quality objectives listed in Rule R9-8 (assuming that the Commission eliminated the Regrade Application Held Orders objective).

The Public Staff proposed that as the Industry Task Force carries out its mission, the Public Staff will simultaneously conduct its own independent evaluation of the service objectives and service quality measurements in North Carolina. The Public Staff stated that it may well be, as the ILEC Coalition suggested, that the Commission should modify certain objectives and establish some entirely new objectives to monitor service quality in the current digital/fiber network environment. The Public Staff maintained that its goal in this process would be to ensure that the Commission gives appropriate consideration to the needs of the using and consuming public as it weighs possible changes to the objectives.

WHEREUPON, the Commission now reaches the following

CONCLUSIONS

First and foremost, the Commission would like to take this opportunity to express its ardent interest in the level and adequacy of service North Carolina customers receive from telephone companies. The Commission routinely hears complaints from the public on a formal and an informal basis on the less than adequate level of service they are receiving from telephone companies. The Commission intends to take all necessary actions to see that this problem is corrected as soon as possible.

After reviewing the filings made in this docket, the Commission has identified the following issues to be addressed:

I - Regrade Application Held Orders Not Completed Within 30 Days:

As the Public Staff and the Companies noted, no company provides multiparty service in North Carolina today. Therefore, the Public Staff recommended that the Commission delete this objective from Rule R9-8. The Commission agrees with the Public Staff's recommendation.

CONCLUSIONS: Based on the record of evidence on this objective, the Commission concludes that it is appropriate to delete the Regrade Application Held Orders Not Completed Within 30 Days objective from Rule R9-8.

II - Explanations of Measurement Procedures for Service Quality Objectives:

The Commission agrees with the Public Staff that the "clear, detailed explanations" of the measurement procedures submitted by the ILECs and CLPs do not provide an adequate level of detail. In fact, the Commission believes that most of the explanations filed by the companies provide virtually no useful information on how the companies will report each of the service objectives outlined in Rule R9-8.

However, the Commission does not agree with the Public Staff that the Commission should require the companies to file revised and upgraded clear, detailed explanations by March 31, 2001 for the last twelve objectives in Rule R9-8. The Commission is not very optimistic that the companies would provide much better information. Further, the Commission would rather see the companies use their resources to participate on the Industry Task Force to develop a uniform set of measurement procedures.

CONCLUSIONS: The Commission will not require the companies to file revised and upgraded "clear, detailed explanations" of their measurement procedures for the service objectives listed in Rule R9-8.

III - Request for Formation of an Industry Task Force:

The Commission notes that all of the Parties are recommending that the Commission establish an Industry Task Force. However, the Public Staff did not indicate in its Comments that it would be willing to participate on such a task force.

The Commission believes that it may be beneficial to order the formation of an Industry Task Force. However, the Commission is concerned that without the participation of the Public Staff and the Attorney General, the interests of the using and consuming public will not be adequately represented on the Industry Task Force. The Commission has been and continues to be very concerned about the deterioration in service quality. However, the Commission is not comfortable that an Industry Task Force without representation by the Public Staff and the Attorney General would develop an adequate set of service objectives to replace the current Rule R9-8 objectives.

Additionally, the Commission notes that the Public Staff has requested that instead of participating on the Industry Task Force, it be allowed to perform its own independent evaluation of the service objectives in Rule R9-8. The Commission believes that directing the Industry Task Force to examine the service objectives in Rule R9-8 simultaneously as the Public Staff performs its independent evaluation could potentially waste the resources of both the Industry and the Public Staff as both the Industry and the Public Staff would develop different proposals for Rule R9-8. The Commission believes that a more reasonable course of action would be to allow the Public Staff to complete its independent evaluation while the Industry Task Force creates a set of uniform measurement procedures [See discussion below IV - Public Staff Evaluation]. The Commission believes that after the Public Staff completes its review and submits its findings to the Commission, the Commission will be in a better position to determine the next course of action for the docket, which could include requesting the Industry Task Force to evaluate and comment on the Public Staff's findings and recommendations.

Therefore, the Commission believes that it would be appropriate to order the formation of an Industry Task Force with its first objective to be to establish a uniform set of measurement procedures for ten of the service objectives listed in Rule R9-8, as follows:

(1) Operator "O" answertime
(2) Directory assistance answertime
(3) Business office answertime
(4) Repair service answertime
(5) Initial customer trouble reports (excluding repeat reports)
(6) Repeat reports
(7) Out-of-service troubles cleared within 24 hours
(8) Regular service orders completed within 5 working days
(9) New service installation appointments not met for Company reasons
(10) New service held orders not completed within 30 days

Additionally, the Commission finds it appropriate to require the Industry Task Force to submit a final version of agreed-upon measurement procedures for the R9-8 service objectives listed above by no later than June 21, 2001.

The Commission would like to further note that nothing in this Order is intended to preclude the Task Force from conferring informally among themselves on possible revisions to Rule R9-8.

CONCLUSIONS: The Commission hereby establishes an Industry Task Force. Further, the Commission hereby directs the Task Force to develop a set of uniform measurement procedures for ten of the service objectives outlined in Rule R9-8 and listed above. The Task Force shall submit its set of uniform measurement procedures to the Commission by no later than June 21, 2001. Nothing in this Order is intended to preclude the Task Force from conferring informally among themselves on possible revisions to Rule R9-8.

<u>IV - Public Staff Independent Evaluation</u>:

The Public Staff proposed in its Comments that as the Industry Task Force carries out its mission, the Public Staff would simultaneously conduct its own independent evaluation of the service objectives and service quality measurements in North Carolina. The Public Staff stated that it may well be, as the ILEC Coalition suggested, that the Commission should modify certain objectives and establish some entirely new objectives to monitor service quality in the current digital/fiber network environment. The Public Staff maintained that its goal in this process would be to ensure that the Commission gives appropriate consideration to the needs of the using and consuming public as it weighs possible changes to the objectives.

The Commission agrees with the Public Staff that it would assist the Commission in this docket if the Public Staff conducted its own independent evaluation of the objectives in Rule R9-8. Further, although the Public Staff did not directly so state, it is reasonable to assume that the Public Staff could be more effective and helpful by conducting its own evaluation rather than participating on the Industry Task Force as the lone voice representing the using and consuming public. Therefore, the Commission hereby requests that the Public Staff undertake an independent evaluation of the service objectives in Rule R9-8 and file a report with the Commission with specific recommendations by no later than June 21, 2001.

The Commission further requests that the Public Staff specifically consider two issues in its review of Rule R9-8. First, the Commission requests that the Public Staff explore and provide specific recommendations on a self-enforcing penalties provision for inclusion in Rule R9-8. Self-enforcing penalties could potentially provide more incentive for companies to meet the service objectives in Rule R9-8. Since the Commission is fervently concerned with the adequacy of service North Carolina telephone users receive, the Commission believes that consideration should be given to a self-enforcing penalities provision in Rule R9-8.

Additionally, the Commission continues to be deeply concerned about the level of service which customers receive from directory assistance providers. The Commission continuously hears of situations where consumers are given incorrect information from directory assistance. Therefore, the Commission requests the Public Staff to consider objectives which would address the level of accuracy which callers to directory assistance receive and provide specific recommendations and comments on the issue in its report.

CONCLUSIONS: The Commission hereby requests the Public Staff to undertake an independent evaluation of the service objectives in Rule R9-8 and file a report with the Commission with specific recommendations no later than June 21, 2001. The Public Staff is requested to specifically consider self-enforcing penalities and accuracy of directory assistance and provide specific recommendations on these issues in its report.

V - Reporting Requirement:

The Public Staff recommended in its Comments that the Commission continue to require all ILECs and CLPs subject to Rule R9-8 to adhere to the reporting schedule established in the November 29, 2000 Order with the first report due March 20, 2001 and monthly thereafter, but recommended that the reporting requirement be limited, for the time being, to the following ten objectives in Rule R9-8:

(1) Operator "O" answertime
(2) Directory assistance answertime
(3) Business office answertime
(4) Repair service answertime
(5) Initial customer trouble reports (excluding repeat reports)
(6) Repeat reports

(7) Out-of-service troubles cleared within 24 hours
(8) Regular service orders completed within 5 working days
(9) New service installation appointments not met for Company reasons
(10) New service held orders not completed within 30 days

The Commission agrees with the Public Staff that it should continue to require the companies to file their monthly service objective reports. The Commission also agrees with the Public Staff's recommendation to alter the reports to only include the ten objectives listed above. The Commission believes that these are the most important objectives and will provide the Commission with the most useful information. The Commission notes that the first report was due on March 20, 2001. With the timing of this matter, the March 20th reports will not be affected by the Commission's decision herein. Therefore, the Commission will require the Parties to conform to the decisions reached in this matter in their monthly reports beginning on April 20, 2001, and monthly thereafter.

CONCLUSIONS: The Commission hereby requires the companies to file the monthly report on the ten objectives listed above beginning on April 20, 2001, and monthly thereafter.

IT IS, THEREFORE, ORDERED as follows:

1. That Rule R9-8 is amended to delete the Regrade Application Held Orders Not Completed Within 30 Days objective.

2. That the ILEC Coalition's request for the Commission to establish an Industry Task Force is hereby granted.

3. That the Industry Task Force shall establish a uniform set of measurement procedures for the ten objectives outlined in Rule R9-8 and listed below in Ordering Paragraph No. 5. The Task Force shall file the uniform set of measurement procedures with the Commission no later than June 21, 2001.

4. That the Public Staff is hereby requested to perform its proposed evaluation on Rule R9-8, service quality, and appropriate measures and file a report with the Commission detailing its evaluation and providing specific recommendations by no later than June 21, 2001. The Public Staff is requested to specifically consider self-enforcing penalities and accuracy of directory assistance and provide specific recommendations on those issues in its report.

5 That the companies shall continue to file reports on the Rule R9-8 service objectives, but the reporting requirement shall be limited to cover only ten of the Rule R9-8 service objectives. The ten service objectives that the companies are required to report are listed below:

(1) Operator "O" answertime
(2) Directory assistance answertime
(3) Business office answertime
(4) Repair service answertime
(5) Initial customer trouble reports (excluding repeat reports)
(6) Repeat reports
(7) Out-of-service troubles cleared within 24 hours

(8) Regular service orders completed within 5 working days
(9) New service installation appointments not met for Company reasons
(10) New service held orders not completed within 30 days

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

bp032001.01

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Telecommunications Relay Service (TRS),) ORDER AUTHORIZING PAYMENT
Relay, North Carolina) OF FUNDS TO SPRINT TRS

BY THE COMMISSION: On June 21, 2000, the Federal Communications Commission (FCC) published revised Rules and Orders for the Telecommunications Relay Service (TRS). These revisions required all state TRS programs to increase operator typing speeds to sixty words per minute, have the capability of handling emergency calls immediately, establish ten minute minimum times for operators to handle a standard TRS call, maintain a log of consumer complaints that must be filed with the FCC, and transfer TRS customer profiles to the incoming TRS vendor at the end of the contract. Sprint TRS submitted a proposal on August 31, 2000, to upgrade North Carolina's TRS program so that it would be in compliance with the new FCC requirements through the end of its contract period, March 31, 2004. The cost of the revisions through the end of the Sprint TRS contract is $1,118,447.

The Public Staff presented this matter at the Commission Staff Conference on April 2, 2001. The Public Staff stated that Sprint TRS had provided sufficiently detailed information to satisfy both it and the administrator of the NC TRS program, a division of the Department of Health and Human Services. The Public Staff recommended that the Commission issue an order authorizing the NC TRS program to pay Sprint $1,118,447 from TRS funds.

IT IS, THEREFORE, ORDERED that the North Carolina TRS program, a division of the Department of Health and Human Services, is hereby authorized to pay Sprint TRS $1,118,447 from TRS funds for the purpose of paying for enhancements to the TRS service as mandated by the FCC.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb040301.14

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Telecommunications Relay Service	)	ORDER AUTHORIZING INCREASE
(TRS)	)	OF SURCHARGE

BY THE COMMISSION: On October 2, 2001, the Commission received a letter from the Department of Health and Human Services (DHHS) requesting that, pursuant to G.S. § 62-157, the Commission increase the monthly surcharge for the Telecommunications Relay Service (TRS) from $ 0.07 to $ 0.11 per month. The monthly surcharge funds TRS's operations entirely. The letter indicated that TRS was presently operating at a loss and would exhaust its funds completely by early 2002 without an increase in the surcharge.

In response to this request, the Commission issued an Order Requesting Comments Regarding Surcharge Increase on October 4, 2001. The Order required interested parties to this docket to file comments regarding the proposed increase no later than October 19, 2001. Reply comments were to be filed no later than Friday, November 2, 2001. In addition, the Commission ordered the Public Staff to investigate the advisability of increasing the surcharge and to present its recommendations to the Commission at Commission Staff Conference on Tuesday, November 13, 2001.

The Commission received no comments regarding the surcharge increase. Accordingly, the Public Staff presented the matter at Commission Staff Conference on November 13, 2001, and recommended that the Commission increase the surcharge from $.07 to $.11 per month. In support of its recommendation, the Public Staff noted that when the Commission first implemented the TRS surcharge in 1991, it was $ .11 per month. In 1994, the Commission ordered that the surcharge be reduced from $.11 to $.07 because funds had accumulated in excess of one million dollars in reserve. The monthly surcharge has remained at $.07 for the last seven years.

At this time, however, the Public Staff's investigation revealed that the $ .07 surcharge no longer provides adequate funds for the operation of TRS. TRS presently pays more in monthly expenses than it receives in revenues through the monthly surcharge. If TRS continues to operate without a surcharge increase, it will exhaust its funds completely by February 2002.

In addition, G.S. § 62-157 requires that TRS maintain a "reasonable" margin for reserve. The Public Staff and representatives of DHHS had previously agreed that one million dollars was an adequate reserve margin because that amount would cover three months of operating expenses in an emergency. That reserve margin amount is now at $389,549.01, well below one million dollars. Moreover, one million dollars is no longer adequate to cover three months of operating expenses. Therefore, the Public Staff and representatives of DHHS agreed that a modest increase in the reserve to 1.2 million dollars was necessary. Based on its review of TRS's current operating expenses and revenues, the Public Staff concluded that an $.11 surcharge would restore the reserve margin and increase it to the necessary 1.2 million dollars in thirteen months.

The Public Staff also noted that, at $ 0.07, North Carolina's surcharge is one of the lowest in the country. A surcharge of S .11 is approximately the average amount charged by the other states with similar programs.

Therefore, the Public Staff recommended that the surcharge be increased effective on January 1, 2002. This date will provide the local service providers adequate time to adjust their billing to reflect the increase in the January bills. The Public Staff recommended that customers be notified of the surcharge increase by a bill message/insert in their January bills as set forth in Appendix A. The Public Staff further recommended that the local service providers should continue to retain $.01 of the $.11 surcharge for collection, inquiry, and administrative expenses.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

1. TRS's monthly expenses presently exceed TRS's monthly revenue.

2. The present surcharge amount of $ .07 per month, which has remained unchanged for the last seven years, no longer provides adequate funds for the operation of TRS. Without an increase in the surcharge, TRS will exhaust its funds completely by February 2002.

3. The Public Staff and representatives of DHHS have recently agreed that the reserve margin should be 1.2 million dollars.

4. Based on its investigation of operating expenses and revenues, the Public Staff recommends that the surcharge be increased from $ .07 to $.11 per month, effective January 1, 2002, both to operate TRS and to restore the reserve margin. With such an increase, the reserve margin may be restored and increased to the necessary 1.2 million dollars in 13 months.

CONCLUSIONS

Based on the above information, the Commission concludes that the requested surcharge increase is warranted and that the surcharge for TRS be increased to $.11 per month. Customer bills issued on or after January 1, 2002, should reflect this increase.

IT IS, THEREFORE, ORDERED as follows:

1. That the TRS surcharge be increased from $ .07 to $ .11 effective January 1, 2002. The increase should be reflected in customers' bills issued on or after January 1, 2002.

2. That the local service providers be authorized to continue to retain $.01 from the $.11 surcharge for collection, inquiry, and administrative expenses.

3. That the bill message/ insert as set forth in Appendix A shall appear in customers' January bills, issued on or after January 1, 2002.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb111301.02

Appendix A

NOTICE OF TRS SURCHARGE INCREASE

Effective with telephone bills issued on or after January 1, 2002, the Telecommunications Relay Service (TRS) surcharge is $.11. The North Carolina Utilities Commission authorized an increase in the TRS surcharge from $.07 to $.11 to maintain adequate funding of North Carolina's TRS program. The surcharge funds the TRS program which enables persons with hearing, speech, and/or vision impairments to communicate with others by telephone.

DOCKET NO. P-100, SUB 133

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

	)	ORDER REQUIRING
In the Matter of	)	ELECTRONIC FILING OF
Local Exchange and Local Exchange Access	)	INTERCONNECTION
Telecommunications Competition	)	AGREEMENTS AND
	)	APPROPRIATE NOTICE OF
	)	SUPERSEDED AGREEMENTS

BY THE CHAIR: Pursuant to Rule (R)7-4(d), the Commission has required the filing of paper copies of interconnection agreements pertaining to local service for approval. The Public Staff presents these agreements for action at the Commission Regular Conferences. Over the past four years, the number and size of these filings has grown significantly, thus complicating the review process and creating significant storage problems. There have also been problems associated in the tracking superseded agreements. Measures are necessary to purge outdated agreements and to allow efficient and accurate research into interconnection agreements.

Accordingly, as of February 1, 2001, the Chair directs parties filing interconnection agreements to do the following:

1. File all negotiated or arbitrated local interconnection agreements in both hard copy (paper) and electronic (diskette or CD-ROM) formats. Each filed agreement shall be carefully checked by the filing party to verify that the hard copies and electronic copies match. The Public Staff will retain the hard copies for 90 days and then discard them. The Public Staff will retain electronic versions indefinitely.

2. Save the electronic copy as a Word 97 file on a diskette or a CD-ROM.

3. Label with the full legal names of the parties to the agreement and the appropriate docket number identification each diskette or CD-ROM containing an electronic copy of the interconnection agreement, with sufficient space on each label for the Chief Clerk's official date stamp.

4. Include, with respect to the filing of interconnection agreements superseding existing contracts, a list of any interconnection agreements and amendments which the new filing makes obsolete and a list of the agreements and amendments that will remain in effect.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of January, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb012301.13

DOCKET NO. P-100, SUB 133d

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
General Proceeding to Determine	)	RECOMMENDED ORDER
Permanent Pricing for Unbundled	)	CONCERNING GEOGRAPHIC
Network Elements	)	DEAVERAGING

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, beginning September 25, 2000 and ending September 29, 2000

BEFORE: Commissioner William R. Pittman, Presiding; Chairman Jo Anne Sanford, and Commissioner J. Richard Conder

APPEARANCES:

FOR BELLSOUTH TELECOMMUNICATIONS, INC.:

Edward L. Rankin, III, General Counsel, BellSouth Telecommunications, Inc., Post Office Box 30188, Charlotte, North Carolina 28230

J. Phillip Carver, General Counsel, and Michael Twomey, General Counsel, BellSouth Telecommunications, Inc., 675 West Peachtree Street, N.E., Atlanta, Georgia 30375

FOR VERIZON SOUTH, INC.:

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Kelly L. Faglioni, Ed Fuhr, and Eric Feiler, Hunton & Williams, RiverFront East, 951 East Byrd Street, Richmond, Virginia 23219

FOR SPRINT COMMUNICATIONS COMPANY L.P.:

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FOR THE NEW ENTRANTS:

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FOR AT&T COMMUNICATIONS OF THE SOUTHERN STATES, INC.:

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FOR WORLDCOM, INC.:

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

Kennard B. Woods, WorldCom, Inc., Concourse Corporation Center Six, 6 Concourse Parkway, Suite 300, Atlanta, Georgia 30328

FOR THE NORTH CAROLINA TELECOMMUNICATIONS ASSOCIATION, AND TIME WARNER TELECOM OF NORTH CAROLINA:

Marcus Trathen, Brooks, Pierce, McLendon, Humphrey & Leonard, L.L.P., Post Office Box 1800, Raleigh, North Carolina 27602

FOR THE USING AND CONSUMING PUBLIC:

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

Kevin Anderson, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27510

BY THE COMMISSION: By this Order, the Commission will address the geographic deaveraging of unbundled network element (UNE) rates.

Federal Communications Commission (FCC) Rule 51.507(f) states:

> State commissions shall establish different rates for elements in at least three defined geographic areas within the state to reflect geographic cost differences.
>
> (1) To establish geographically-deaveraged rates for elements in at least three defined existing density-related zone pricing plans described in §69.123 of this chapter, or other such cost-related zone plans established pursuant to state law.
> (2) In states not using such existing plans, state commissions must create a minimum of three cost-related rate zones.

FCC Rule 51.507(f) was challenged on appeal, but was ultimately upheld by the United States Supreme Court in AT&T Corp. v. Iowa Utilities Board, 525 U.S. 366 (1999). After the issuance of the Supreme Court's opinion, the FCC issued an Order on May 7, 1999, staying the effective date of the geographic deaveraging requirement for UNE rates until six months after the issuance of its Order in CC Docket No. 96-45 finalizing and ordering implementation of high-cost universal service support for non-rural local exchange companies (LECs).

The Commission recognized that it would eventually need to take action in response to Rule 51.507(f), even though the Rule had been temporarily stayed. Consequently, in its Order Ruling on Motions for Reconsideration and Clarification and Comments, issued in this docket on August 18, 1999, the Commission ordered that further proceedings be initiated for the purpose of developing geographically deaveraged rates.

On November 2, 1999, the FCC issued a High Cost Universal Service Order in CC Docket No. 96-45, adopting a new universal service support system for non-rural LECs. In its Order, the FCC announced that its stay of Rule 51.507(f) would be lifted on May 1, 2000.

On November 4, 1999, in response to FCC Rule 51.507(f), the Commission issued an Order (1) scheduling a hearing on April 17, 2000 to consider geographic deaveraging of UNEs; (2) approving a list of issues to be considered on the subject during the hearing; and (3) adopting a schedule of procedural deadlines.

In this Order, the Commission discusses each of the relevant geographic deaveraging issues identified by the Commission in its November 4, 1999 Order, along with a Commission Conclusion on each issue. The following issues were outlined in the Commission's November 4, 1999 Order for consideration in this matter:

1. What is geographic deaveraging and what geographic deaveraging of UNEs and UNE combinations should be undertaken by the Commission?

2. Which UNEs must be deaveraged? Which UNEs are not required to be deaveraged?

3. Which UNE combinations must be deaveraged? Which UNE combinations are not required to be deaveraged?

4. For UNEs and UNE combinations that are deaveraged, what recurring and nonrecurring costs must be deaveraged?

5. What level of geographic deaveraging should be adopted (e.g., wire center groups, wire center, or loop length within wire center)?

6. Should the degree of geographic deaveraging be uniform for all UNEs and UNE combinations for which the Commission requires geographic deaveraging?

7. Should the degree of geographic deaveraging be uniform for all incumbent local exchange companies (ILECs) for which deaveraged rates are required by the Commission?

8. What other factors or policy considerations, if any, should be considered in determining deaveraged UNE rates (e.g., universal service impact, stimulation of competition, retail rates, public policy, and/or company size)?

9. What are the appropriate rates for those UNEs and UNE combinations that a party proposes to be deaveraged?

On January 11, 2000, the Commission ordered that the procedural schedule for geographic deaveraging be held in abeyance pending the issuance of an Order adopting final UNE rates.

By Order dated March 13, 2000, the Commission adopted final UNE rates.

On March 30, 2000, the Commission issued an Order adopting procedural schedules to consider several issues, among them was the geographic deaveraging of UNE rates. The Order established a Phase I proceeding to consider geographic deaveraging of UNE rates, the FCC's UNE Remand Order, and the FCC's Line Sharing Order.

On April 17, 2000, the Commission filed a Petition with the FCC requesting a twelve-month waiver of the requirement of FCC Rule 51.507(f) that geographically deaveraged rates be adopted by May 1, 2000.

On April 24, 2000, the Commission issued an Order Modifying Procedural Schedules. In that Order, the Commission postponed the Phase I hearing until September 25, 2000.

On April 27, 2000, the FCC issued an Order denying the Commission's request for a twelve-month waiver, but granted the Commission a six-month waiver of the Rule through October 31, 2000.

On June 6, 2000, the New Entrants, AT&T, and MCI WorldCom filed a Motion requesting that the Commission adopt interim geographically deaveraged rates for all UNEs.

On June 9, 2000, BellSouth Telecommunications, Inc. (BellSouth) filed the testimony and exhibits of Cynthia K. Cox, D. Daonne Caldwell, W. Keith Milner, and Ronald M. Pate, and Verizon South, Inc. (Verizon) filed the testimony and exhibits of John J. Boshier, Terry L. Bachman, Stephen L. Schroeder, Kevin C. Collins, Linda Casey, and Bert I. Steele. On June 13, 2000, Carolina Telephone & Telegraph Company, Central Telephone Company, and Sprint Communications Company L.P. (collectively Sprint) filed the testimony and exhibits of Kent W. Dickerson, Steven M. McMahon, and Michael R. Hunsucker.

In comments filed on July 20, 2000, the ILECs and the Public Staff opposed the June 6, 2000 Motion requesting that the Commission adopt interim geographically deaveraged rates for all UNEs.

On August 11, 2000, the New Entrants filed the testimony and exhibits of Michael Zulevic, Peter J. Gose, Warren R. Fischer, Thomas J. Mitchell, and a panel consisting of Michael Starkey and Eric W. McPeak; WorldCom filed the testimony and exhibits of Greg Darnell; AT&T filed the testimony and exhibits of Gregory J. Beveridge and Jeffrey King; the North Carolina Cable Telecommunications Association (NCCTA) filed the testimony and exhibits of William J. Barta; and the Public Staff filed the testimony and exhibits of John T. Garrison, Jr. Sprint, in its capacity as an intervenor, filed the testimony and exhibits of Kent W. Dickerson, Steven M. McMahon, and Michael R. Hunsucker.

On August 14, 2000, the Commission issued an Order which stated that a ruling on the June 6, 2000 Motion for interim geographically deaveraged UNE rates would be held in abeyance.

On September 15, 2000, BellSouth filed the rebuttal testimony and exhibits of Cynthia K. Cox, D. Daonne Caldwell, William H. B. Greer, Wiley Gerald Latham, Jr., W. Keith Milner, and Ronald M. Pate. Verizon filed the rebuttal testimony and exhibits of R. Kirk Lee, who adopted the direct testimony of John J. Boshier; Terry L. Bachman; Russell A. Bykerk, who adopted the direct testimony of Stephen L. Schroeder; Kevin C. Collins; Linda Casey; and Bert I. Steele. Sprint filed the rebuttal testimony and exhibits of Kent W. Dickerson, Steven M. McMahon, and Michael R. Hunsucker.

An evidentiary hearing on geographic deaveraging was held before the Commission Hearing Panel beginning on September 25, 2000. At the hearing, New Entrants witness Gose adopted the prefiled direct testimony of Warren R. Fischer.

On November 3, 2000, the New Entrants filed a Motion requesting a modification to the briefing schedule in this docket.

On November 8, 2000, the Commission issued an Order granting the New Entrants' Motion thereby directing the Parties to file Proposed Orders and Briefs on the geographic deaveraging issue by December 1, 2000.

On December 1, 2000, the Parties filed their Proposed Orders and Briefs addressing the issue of geographic deaveraging.

WHEREUPON, the Commission now makes the following

FINDINGS OF FACT

1. The appropriate definition of geographic deaveraging is as follows: geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or company-wide average. Further, the Commission rejects Verizon's proposal that North Carolina is already in compliance with FCC Rule 51.507(f) since it has adopted UNE prices for each of the four major ILECs in the State and concludes that geographic deaveraging of each ILEC's UNE rates must be undertaken by the Commission to comply with FCC Rule 51.507(f).

2. It is appropriate to geographically deaverage the local loop and subloops. There does not appear to be any controversy that the local channel below the DS3 level should be geographically deaveraged, but the Commission will give Parties the opportunity to make a filing with the Commission by no later than April 4, 2001 outlining any reasons for disagreement.

3. Any UNE combination which includes loops or subloops, and possibly local channels below the DS3 level, should be deaveraged.

4. Monthly recurring charges should be deaveraged. Nonrecurring charges should not be deaveraged at this time.

5. Geographic zones should be established at the wire center level by grouping wire centers.

6. It is appropriate to deaverage all UNEs to the same degree by applying the same number of zones.

7. It is appropriate to apply the same geographic deaveraging methodology and zones to all ILECs uniformly.

8. In order to be in compliance with FCC Rule 51.507(f), the Commission must adopt a plan to geographically deaverage UNE rates in this docket. However, the Commission acknowledges that there could be potential negative impacts on retail rates and universal service after adoption of a geographic deaveraging plan. The Commission will consider any impacted issues such as retail rates and universal service in future proceedings after some time has elapsed and the Commission is able to determine the effects of imposing its geographic deaveraging plan.

9. In order to establish geographically deaveraged UNE rates, wire centers should be grouped into zones as follows:

> Zone 1 - All wire centers with a UNE cost of 115% or less of the statewide average for that UNE.
>
> Zone 2 - All wire centers with a UNE cost of 115% to 160% of the statewide average for that UNE.
>
> Zone 3 - All wire centers with a UNE costs of 160% or greater of the statewide average for that UNE.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

ISSUE NO. 1: What is geographic deaveraging and what geographic deaveraging of UNEs and UNE combinations should be undertaken by the Commission?

POSITIONS OF PARTIES

BELLSOUTH: Geographic deaveraging establishes different rates for UNEs in at least three defined geographic areas within the State to reflect geographic cost differences.

CAROLINA/CENTRAL/SPRINT: For purposes of this docket, the Commission should define the term "geographic deaveraging" as the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or companywide average. The forward-looking economic costs of providing network elements are not necessarily uniform throughout the service territory of most ILECs, and can vary substantially in different areas of an ILEC's service territory. Factors such as population density, climate and weather conditions, the distances involved, and the type of terrain can greatly impact the cost of various network components in different geographic areas. Using a companywide average, or a statewide average of the ILEC's costs as a basis for pricing network elements to competing local providers (CLPs) may result in UNEs being greatly overpriced in some areas (in relation to the actual cost to the ILEC of providing the UNE), and underpriced in other areas. Such results can be economically harmful to both CLPs and ILECs, and tend to frustrate one of the main objectives of the Telecommunications Act of 1996 (the Act or TA96) to promote fair competition in providing local telephone service. Based on the foregoing, and to ensure UNE pricing that is more in line with the ILECs' underlying cost of providing UNEs and thereby facilitate the development of fair competition in providing local telephone service in North Carolina, the Commission should adopt the geographically deaveraged rates proposed by Sprint.

NCCTA: Did not specifically address this issue in its Brief.

NEW ENTRANTS: Geographic deaveraging is the process of establishing UNE rates based on the variation in costs of provisioning network elements across distinct geographic areas.

PUBLIC STAFF: The rules of the FCC require the Commission to establish geographically deaveraged rates for those UNEs and UNE combinations whose costs vary significantly on the basis of location. The Commission is required to establish at least three cost-related rate zones, and the zones need not be based on the existing service areas of the State's ILECs.

VERIZON: The Commission is not required to, nor should it, deaverage UNE rates beyond the current level in North Carolina. Rates in North Carolina are presently deaveraged into four zones, one for each ILEC participating in this proceeding (i.e., BellSouth, Carolina, Central, and Verizon).

WORLDCOM AND AT&T: Geographic deaveraging is the process of establishing UNE rates based on the variation in costs of provisioning network elements across distinct geographic areas. Costs should be deaveraged by estimating wire center costs and grouping them such that a weighted average rate from any wire center grouping does not deviate from the costs of any wire center by more than 20%. This methodology complies with the statutory and regulatory requirements for geographic deaveraging and should be adopted by the Commission.

DISCUSSION

There is little controversy between the Parties over the appropriate definition of geographic deaveraging. The Parties generally agree that geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or companywide average. Starting with that definition, it would be reasonable to assume that the Parties agree that the Commission should undertake geographic deaveraging UNEs whose cost varies by geographic location. The disagreement arises when determining which UNEs have costs that vary by geographic location.

The Commission finds it appropriate to adopt the following definition of geographic deaveraging: geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or company-wide average.

Concerning the question of what geographic deaveraging of UNEs and UNE combinations should be undertaken by the Commission, all of the Parties except Verizon believe the Commission should order some degree of geographic deaveraging. Verizon, however, proposed that North Carolina is already in compliance with the FCC Rule.

Verizon witness Steele testified that the Commission is already in compliance with FCC Rule 51.507(f) and is not required to engage in any further geographic deaveraging in this case. He argued that the only requirement Rule 51.507(f) imposes on state commissions is to "create a minimum of three cost-related rate zones." Witness Steele maintained that the Commission has set UNE rates at different levels for the service areas of the State's four major ILECs (BellSouth, Verizon, and Sprint's subsidiaries Carolina and Central), and these rates are cost-based, since they are based on each company's statewide average forward-looking economic costs. Consequently, witness Steele asserted, the Commission has done all that the FCC Rule requires.

In support of his position, witness Steele relied heavily on the FCC's April 28, 2000 Order granting the requests of Ohio, North Carolina, and various other states for waivers of the May 1, 2000 deadline for compliance with Rule 51.507(f). In its comments filed on April 21, 2000 in support of its waiver request, the Ohio Public Utilities Commission stated that "[n]either the FCC's rule . . . nor its prior orders on rate deaveraging specifically require that company-specific rate zones be established for each and every non-rural carrier by May 1, 2000." In granting Ohio's requested waiver, the FCC stated:

> We note that Ohio argues it may not need this waiver. As it points out, the FCC has never ruled that states must create company-specific zones for each carrier in the state, but only that the state commissions must have at least three deaveraged rates in total.

In the same Order the FCC also granted, in part, the North Carolina Utilities Commission's request for a waiver, noting "that North Carolina may not need a waiver for the same reasons cited above in our discussion of Ohio's request." Witness Steele stated that none of the other states formerly served by GTE has ordered Verizon to create three deaveraged rate zones.

Sprint witness Hunsucker stated in his direct testimony that he did not agree with Verizon's position that the Commission did not have to deaverage further since it had established UNE rates for four ILECs. Witness Hunsucker stated that adopting a single, average rate for each ILEC fails to recognize the wide cost differences within each of the ILEC's operating territories. Witness Hunsucker noted that Verizon apparently is equally not impressed with its argument as it has proposed to deaverage its loop prices in three zones for Verizon alone.

During cross-examination, WorldCom witness Darnell stated that the FCC's Rules do not specifically require the Commission to create a minimum of three zones for each ILEC. However, witness Darnell opined, it would be "silly" for the FCC to write a Rule under the impression that it does not apply to anybody. Witness Darnell argued that the Rule was written to deaverage each ILEC's rates into a minimum of three geographic zones.

Based on the record in this proceeding, the Commission rejects Verizon's proposal that the Commission need not further deaverage UNE rates to be in compliance with FCC Rule 51.507(f). The Commission notes that the language in the Rule is subject to two reasonable, but conflicting, interpretations. However, the Commission notes that all of the Parties other than Verizon have argued, or simply assumed, that the Rule requires the Commission to establish deaveraged rate zones within the service area of each of the State's major ILECs.

Further, the Commission does not believe that the FCC's April 28, 2000 Order provides real support for Verizon's position when viewed in its proper context. In applying for a waiver of the May 1 geographic deaveraging deadline, the Ohio Public Service Commission was not contending that it could properly designate the service area of each ILEC in the State as a single rate zone. In its comments submitted to the FCC, the Ohio Commission noted that it had already created three deaveraged zones for the State's two ILECs serving metropolitan areas, and it was only seeking time to complete its geographic deaveraging proceedings for the other two ILECs in the State. The comments specifically stated that "clarifying that Ohio has already fulfilled the deadline will not affect Ohio's ongoing support for, and implementation of, geographic rate deaveraging. Instead, the FCC's ruling will only affect the time of full and final implementation of the deaveraging concept . . . ." Similarly, the waiver request filed by the North Carolina Utilities Commission stated that "[t]he NCUC has been working diligently to develop geographically deaveraged UNE rates" and did not contend that the geographic deaveraging requirement could be satisfied by designating each ILEC's service area as a rate zone. The FCC referred to the Ohio Commission's argument in its April 28, 2000 Order and the FCC simply noted that the issue was "beyond the scope of our consideration of the waiver petitions"; it did not endorse the argument. Therefore, the Commission notes, the FCC's April 28, 200 Order neither supports nor contradicts Verizon's position, and it provides the Commission no real assistance in interpreting FCC Rule 51.507(f).

Based on the foregoing, the Commission rejects Verizon's proposal and concludes that geographic deaveraging of each ILEC's UNE rates must be undertaken by the Commission to comply with FCC Rule 51.507(f).

CONCLUSIONS

The Commission concludes that the appropriate definition for geographic deaveraging is as follows: geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or companywide average.

Further, the Commission rejects Verizon's proposal and concludes that geographic deaveraging of each ILEC's UNE rates must be undertaken by the Commission to comply with FCC Rule 51.507(f).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

ISSUE NO. 2: Which UNEs must be deaveraged? Which UNEs are not required to be deaveraged?

POSITIONS OF PARTIES

BELLSOUTH: Only loops, subloops, and local channels below the DS3 level should be geographically deaveraged. No other UNEs should be deaveraged. Because rates for elements resulting from the FCC's UNE Remand Order are being considered separately from the deaveraging issue, BellSouth will propose its deaveraged rates for the applicable UNE Remand elements with its brief addressing those elements. **NOTE:** BellSouth witness Cox testified in direct testimony that subloops should be deaveraged. However, BellSouth did not include subloops in its list of UNEs that should be deaveraged in its Proposed Order.

CAROLINA/CENTRAL/SPRINT: Section 252 of the Act and the FCC's Rules require that UNEs whose costs vary significantly by geographic region be deaveraged which would include loops, subloops, local switching ports and local switching usage, tandem switching, common and dedicated transport, and dark fiber.

NCCTA: Did not specifically address this issue in its Brief.

NEW ENTRANTS: The rates for UNEs that exhibit significant cost variances on a geographic basis should be deaveraged. These UNEs include loops, subloops, unbundled transport facilities, and dark fiber.

PUBLIC STAFF: The only UNEs that need to be deaveraged are local loops (i.e., analog loops and digital loops with speeds up to 1.544 Mbps), together with feeder and distribution subloop elements for these loops.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. If the Commission mandates geographic deaveraging on a company-specific basis, only loop prices should be deaveraged, because only loop costs show significant variation between different geographic areas.

WORLDCOM AND AT&T: The rates of UNEs that exhibit significant cost variances on a geographic basis should be deaveraged. Therefore, rates for unbundled loops, subloops, transport facilities, and dark fiber should be geographically deaveraged.

DISCUSSION

All of the Parties appear to agree that only those UNEs whose costs vary depending on geographic location should be deaveraged. In the record, however, there is conflicting evidence concerning which UNE costs actually vary by geographic location.

(A) LOCAL LOOP

All Parties agreed that the local loop is a UNE that must be geographically deaveraged if the Commission mandates geographic deaveraging on a company-specific basis. As Sprint witness Dickerson testified, the cost of local loops varies more on a geographic basis than any other network element. Witness Dickerson stated that numerous factors affect the cost of providing local loops to a specific customer location including customer density, distance, terrain, weather, and local market conditions.

The Public Staff stated in its Proposed Order that the largest cost component of local exchange service is the local loop. Further, the Public Staff noted that both the Alabama and Tennessee Public Service Commissions ordered only geographic deaveraging of the local loop.

No Party denied that the local loop costs show significant variation between different geographic locations.

The record of evidence clearly shows that the Parties unanimously agree that local loop costs vary based on the geographic location of the loop and, therefore, should be geographically deaveraged if the Commission requires geographic deaveraging on a company-specific basis.

CONCLUSION: The Commission concludes that it is appropriate to deaverage the local loop.

(B) SUBLOOP

Further, as it is linked to the local loop, all of the Parties except Verizon agreed that the cost of the subloop varies by geographic location and, therefore, the subloop must be geographically deaveraged. The FCC defined subloops in its UNE Remand Order as portions of the local loop that can be accessed at terminals in the ILEC's outside plant. Since the subloop represents a portion of the local loop, it is logical to conclude that the cost of the subloop varies by geographic location. Therefore, the Commission concludes that it is appropriate to geographically deaverage the subloop.

The Commission notes that currently there are no statewide average subloop rates approved by the Commission. The issue of subloops was raised in the FCC's UNE Remand Order. The Commission held an evidentiary hearing on the issue, and Proposed Orders and Briefs have been filed concerning subloops. However, the issue of subloop rates is still under consideration by the Commission.

CONCLUSION: The Commission concludes that it is appropriate to deaverage the subloop.

(C) LOCAL CHANNELS

BellSouth recommended that the local channel below the DS3 level be deaveraged as well. BellSouth witness Cox explained during cross-examination that the local channel is the facility from the BellSouth serving wire center to the CLP's point of presence. BellSouth witness Caldwell explained on cross-examination that the local channel is the facility that goes from the BellSouth central office to the CLP central office.

In reviewing the permanent UNE rates established by the Commission in March 2000, it appears that BellSouth is the only ILEC with rates for the local channel.

MCIm witness Darnell did not address local channels in his testimony although in his exhibit, Attachment 1, witness Darnell did list local channels as a UNE. However, it appears from Attachment 1 that MCIm is not proposing that the local channel for BellSouth be geographically deaveraged.

New Entrants witnesses Starkey and McPeak also did not address the issue of local channels in their testimony, however, in their exhibit, Exhibit NEP-3, the New Entrants listed local channels as a UNE. It appears from the Exhibit that the New Entrants are proposing that the local channel for BellSouth be geographically deaveraged.

The Commission does not believe that the record of evidence on this issue is clear or sufficient. The Commission notes that there does not appear to be any controversy that the local channel should be deaveraged, but the Commission is not certain of this fact. Therefore, the Commission finds it appropriate to allow any Party which disagrees that the local channel should be deaveraged the opportunity to make a filing with the Commission by no later than April 4, 2001 detailing the reasons for its disagreement.

CONCLUSION: The Commission concludes that there does not appear to be any controversy concerning geographic deaveraging of the local channel below the DS3 level but that Parties will be given the opportunity to make a filing with the Commission by no later than April 4, 2001 detailing any reasons for disagreement.

(D) TRANSPORT FACILITIES

Sprint, the New Entrants, WorldCom, and AT&T argued that the cost of transport facilities varies by geographic location and, therefore, should be geographically deaveraged.

Sprint witness Dickerson stated in direct testimony that interoffice transport costs vary between specific geographic points due to the underlying variances in traffic volumes, distances, and SONET ring designs that commonly occur in the network.

BellSouth witness Cox stated in direct testimony that the price of interoffice transport reflects any cost differences due to geographic location. Witness Cox asserted that the rate structure for interoffice transport is on a per mile basis which reflects length and, therefore, there is no need for further geographic deaveraging. During cross-examination, however, witness Cox stated that interoffice transport is priced on a mileage basis so to an extent it is deaveaged, just not geographically deaveraged. Witness Cox clarified that BellSouth does not in any way deaverage the per mile rate.

In rebuttal testimony, BellSouth witness Caldwell explained that one must consider the network as a whole when geographic deaveraging. She explained that, for example, for interoffice transport, one end of the circuit (A) may be in an urban area and the other end (B) in a rural area. Witness Caldwell stated that the question becomes, which end of the circuit should be considered the cost driver: A or

B? Witness Caldwell pointed out that both A and B terminations must be considered since the traffic load riding the circuit is determined by both ends, not just one.

Verizon stated in its Brief that the rates for interoffice transmission facilities already reflect distance, traffic, and volume characteristics that effectively deaverage those UNE offerings.

The Public Staff noted in its Proposed Order that existing rates for some UNEs, such as interoffice transport, are generally calculated on a per-mile basis. Consequently, the Public Staff maintained that these rates already take into account, to some extent, geographical differences in costs.

The Commission believes that the record of evidence does not clearly demonstrate that the cost of transport facilities varies in a material respect based on geographic location. Since the record of evidence is not conclusive on this issue, the Commission concludes that it is not appropriate to deaverage transport facilities at this point in time.

CONCLUSION: The Commission concludes that it is not appropriate to deaverage transport facilities at this point in time.

(E) DARK FIBER

Sprint, the New Entrants, WorldCom, and AT&T argued that the cost of dark fiber varies by geographic location and, therefore, must be geographically deaveraged.

Sprint witness Dickerson stated in direct testimony that its cost study for dark fiber shows significant variation by geographic location.

The New Entrants stated in their Proposed Order that Sprint did not propose deaveraged rates for dark fiber subloop distribution. The New Entrants argued that dark fiber meets the criteria for geographic deaveraging and that all ILECs should propose deaveraged rates for dark fiber.

New Entrants witness Fisher stated in his direct testimony that Sprint failed to recommend the geographic deaveraging of dark fiber loop distribution. Witness Fisher stated that Sprint proposes geographic deaveraging the dark fiber loop feeder and interoffice transport and not dark fiber loop distribution. Witness Fisher explained that Sprint did not propose geographic deaveraging dark fiber loop distribution because its current wire center level demand for the facility is relatively limited. Witness Fisher opined that Sprint's rationale is inconsistent with Sprint's position that significant cost variations over geographic areas should be the determining factor in deaveraging, not current demand. Witness Fisher recommended that the Commission require Sprint to deaverage dark fiber loop distribution according to its proposed geographic deaveraging methodology.

WorldCom and AT&T stated in their Proposed Order that Sprint did not propose deaveraged rates for dark fiber subloop distribution. WorldCom and AT&T argued that dark fiber meets the criteria for geographic deaveraging and that all ILECs should propose deaveraged rates for dark fiber.

Verizon stated in its Brief that Verizon has proposed rates for dark fiber for the loop, loop distribution, loop feeder, and interoffice transport. Verizon noted that its proposed interoffice dark fiber rates are presented on a termination and facility mile basis. Thus, Verizon argued, its dark fiber rates already take cost differences into account and no additional geographic deaveraging is necessary.

The Commission believes that the record of evidence does not clearly demonstrate that the cost of dark fiber varies in a material respect based on geographic location. Since the record of evidence is not conclusive on this issue, the Commission concludes that it is not appropriate to deaverage dark fiber at this point in time.

CONCLUSION: The Commission concludes that it is not appropriate to deaverage dark fiber at this point in time.

(F) LOCAL AND TANDEM SWITCHING

Only Sprint argued that local and tandem switching exhibits geographic cost differences associated with the numbers of customers served, the calling patterns of those customers, and the volume, time, and nature of the calls made by those customers.

In direct testimony, Sprint witness Hunsucker stated that BellSouth's assertion that switching costs do not vary by geographic region is simply inaccurate. Witness Hunsucker noted that Sprint witness Dickerson explained that switching costs can vary significantly based on such factors as the number of lines served, traffic volumes, nature of calls (intraoffice vs. interoffice), duration of calls, and peak traffic loads. Witness Hunsucker stated that the switching factors definitely drive justifiable differences in costs by location, thus confirming the need for geographic deaveraging.

BellSouth witness Cox asserted in direct testimony that none of the factors that make the loop cost vary by geographic location are present with respect to switching cost calculations.

The New Entrants stated in their Proposed Order that only Sprint proposed to deaverage switching rates. The New Entrants stated that they do not believe that switching costs meet the criteria for geographic deaveraging and, therefore, recommended that the Commission not deaverage switching costs.

Verizon noted in its Brief that although switching costs may vary somewhat based upon the technology used, the size of the switch, and traffic volumes, the different traffic sensitive cost levels are not likely to result in any significant social gains due to geographic deaveraging.

WorldCom and AT&T stated in their Proposed Order that only Sprint proposed to deaverage switching rates. WorldCom and AT&T stated that they do not believe that switching costs meet the criteria for geographic deaveraging and, therefore, recommended that the Commission not deaverage switching costs.

The Commission believes that the record of evidence does not clearly demonstrate that the cost of switching varies in a material respect based on geographic location. The Commission notes that Sprint was the only Party to propose geographic deaveraging of switching costs. Since the record of evidence is not conclusive on this issue, the Commission concludes that it is not appropriate to deaverage switching costs at this point in time.

CONCLUSION: The Commission concludes that it is not appropriate to deaverage switching costs at this point in time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

ISSUE NO. 3: Which UNE combinations must be deaveraged? Which UNE combinations are not required to be deaveraged?

POSITIONS OF PARTIES

BELLSOUTH: Only UNE combinations containing deaveraged loops, deaveraged subloops, and deaveraged local channels below the DS3 level should be deaveraged.

CAROLINA/CENTRAL/SPRINT: The price of a network element combination should reflect the sum of the prices of the network elements that comprise the combination. If a network element combination includes within it one or more network elements that have been deaveraged, then the combination should also be deaveraged. Conversely, if a network element combination does not include at least one element that has been deaveraged, then geographic deaveraging is not required with respect to the combination.

NCCTA: Did not specifically address this issue in its Brief.

NEW ENTRANTS: Geographically deaveraged rates should be required for any network element combination that includes any of the following network elements: unbundled loops, subloops, transport facilities, or dark fiber.

PUBLIC STAFF: UNE combinations that include local loops should be deaveraged, but only with respect to the loop itself and not with respect to the other elements of the combination.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. If the Commission mandates geographic deaveraging on a company-specific basis, only combinations which include loop prices should be deaveraged, because only loop costs show significant variation between different geographic areas.

WORLDCOM AND AT&T: The monthly recurring rates for any UNE combination that includes loops, subloops, transport facilities, or dark fiber should be geographically deaveraged. AT&T believes that the Commission should require ILECs to provide the following UNE combinations: (i) 2-wire voice grade loop, DS0/1 Mux, and DS1 interoffice transport; (ii) 4-wire voice grade loop, DS0/1 Mux, and DS1 interoffice transport; (iii) 4-wire 56 or 64 Kbps loop, DS0/1 interoffice transport; (iv) 4-wire DS1 loop with DS1 interoffice transport; (v) 4-wire DS1 loop, DS1/3 Multiplexer, and DS3 interoffice transport; (vi) DS3 loop with DS3 interoffice transport; (vii) 2-wire voice grade local channel, DS0/1 Mux, and DS1 interoffice transport, (viii) 4-wire voice grade local channel, DS0/1 Mux, and DS1 interoffice transport; (ix) 4-wire DS1 local channel with DS1 interoffice transport; (x) 4-wire DS1 local channel, DS1/3 Mux, and DS3 interoffice transport; and (xi) DS3 local channel with DS3 interoffice transport.

DISCUSSION

Witness Starkey stated in direct testimony that any UNE combination that includes loops, subloops, transport facilities, and/or dark fiber should be deaveraged.

WorldCom and AT&T stated in their Proposed Order that it is logical to require ILECs to geographically deaverage the rate for any UNE combination which includes loops, subloops, transport facilities, and/or dark fiber.

The Commission believes that it is reasonable and appropriate for the Commission to only deaverage those UNE combination which include the individual UNEs the Commission concluded should be deaveraged. The Commission concluded in Finding of Fact No. 2 that it was appropriate to deaverage loops, subloops, and possibly local channels below the DS3 level. Therefore, the Commission concludes that any UNE combination which includes any of the aforementioned UNEs should be deaveraged.

CONCLUSIONS

The Commission concludes that any UNE combination which includes loops or subloops, and possibly local channels below the DS3 level, should be deaveraged.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

ISSUE NO. 4: For UNEs and UNE combinations that are deaveraged, what recurring and nonrecurring costs must be deaveraged? **COMMISSION NOTE:** A more accurate statement of the outstanding issue would be: Should nonrecurring costs be geographically deaveraged?

POSITIONS OF PARTIES

BELLSOUTH: Nonrecurring charges should not be deaveraged because they do not vary by geographic location.

CAROLINA/CENTRAL/SPRINT: There are no significant geographic cost differences in the nonrecurring costs of any ILEC-provided network element in North Carolina, and consequently the Commission should not authorize geographic deaveraging with respect to nonrecurring costs. The Commission should authorize geographic deaveraging only with respect to the recurring costs of the network elements and network element combinations referenced in Sprint's positions for Issue No. 2 and Issue No. 3.

NCCTA: Did not specifically address this issue in its Brief.

NEW ENTRANTS: The monthly recurring rates for any UNE combinations which include loops, subloops, transport facilities, or dark fiber should be geographically deaveraged. The data provided by the ILECs in this proceeding does not appear to support a geographically deaveraged rate structure for nonrecurring rates.

PUBLIC STAFF: It is not appropriate to deaverage the nonrecurring charges for UNEs.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. Verizon did not specifically address geographic deaveraging nonrecurring costs in its Brief or Proposed Order but proposed that only loop costs be deaveraged.

WORLDCOM AND AT&T: Monthly recurring rates for unbundled loops, subloops, transport facilities, and dark fiber should be deaveraged. Nonrecurring rates for UNEs should not be geographically deaveraged at this time.

DISCUSSION

All of the Parties to the proceeding that expressed an opinion on geographic deaveraging nonrecurring rates agree that nonrecurring rates should not be deaveraged at this time. Therefore, the Commission concludes that monthly recurring charges should be deaveraged and that nonrecurring charges should not be deaveraged at this time.

CONCLUSIONS

The Commission concludes that monthly recurring charges should be deaveraged and that nonrecurring charges should not be deaveraged at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

ISSUE NO. 5: What level of geographic deaveraging should be adopted (e.g., wire center groups, wire center, or loop length within wire center)?

POSITIONS OF PARTIES

BELLSOUTH: The appropriate level of geographic deaveraging involves a **grouping of wire centers by rate group**.

CAROLINA/CENTRAL/SPRINT: The level of geographic deaveraging in North Carolina should be based on both administrative ease and a realistic assessment of the extent to which limited rate averaging does not materially impact competition and investment decisions. Based upon these considerations, the Commission should find that ILECs should apply the plus or minus 20% geographic deaveraging criteria at the **wire center level** for network elements such as local loops, subloops, local switching, and dark fiber. Tandem switching and interoffice transport should be reviewed and, if required, deaveraged by tandem switch and interoffice route. The Commission should find that ILECs may group wire centers, switches, and routes into a single rate group so long as the price of a single wire center, switch, or route does not vary from the weighted averaged price for the group by more than 20%.

NCCTA: The Commission should assign wire centers to geographic zones based on a ratio of average loop costs in the wire center to a statewide average.

NEW ENTRANTS: Deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber should be geographically deaveraged at the wire center level.

PUBLIC STAFF: UNEs should be deaveraged at the exchange level, rather than at any other level such as the wire center level.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. If the Commission, however, believes that it must further deaverage UNE rates, then it should adopt a proposal that minimizes the impact on universal service and on residential customers in high-cost areas. If the Commission undertakes further geographic deaveraging, it should be at the wire center level.

WORLDCOM AND AT&T: Deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber should be geographically deaveraged at the wire center level.

DISCUSSION

The significance of this issue relates to the methodology for geographic deaveraging. In Finding of Fact No. 9, the Commission will address the issue of the appropriate methodology the Commission should adopt to form zones to recognize the differing cost of UNEs throughout the BellSouth, Carolina, Central, and Verizon service areas. The issue of the appropriate level of geographic deaveraging (e.g., wire center groups, wire center, or loop length within wire center) would be used as the basis to form the zones discussed in Finding of Fact No. 9.

All of the Parties except BellSouth and the Public Staff recommended geographic deaveraging at the wire center level by grouping wire centers. BellSouth proposed geographic deaveraging by grouping wire centers by rate group while the Public Staff recommended geographic deaveraging by grouping exchanges.

BellSouth witness Cox stated in direct testimony that BellSouth is proposing to deaverage based on existing rate groups. Witness Cox explained that rate groups are geographic areas with similar density characteristics ranging from the most urban areas to the most rural areas. She stated that because the general process of establishing rate groups tends to follow a zoning methodology, existing local exchange rate groups were mapped into one of three zones. Witness Cox explained that on a loop cost basis, Zone 1 rate groups have costs less than 100% of the statewide average cost, Zone 2 costs are between 100% and 150% of the average, and Zone 3 represents costs greater than 150% of the statewide average. Witness Cox argued that by using BellSouth's proposed methodology, customers who are located in the same geographic area and who have similar calling areas will be in the same geographically deaveraged zone for UNE pricing.

On cross-examination, witness Cox agreed that to determine which wire centers are in each proposed BellSouth zone, one would never need to know what the cost is of any wire center. Witness Cox did argue that the cost of the areas are considered. Witness Cox further answered whether cost was or was not directly or specifically a component of the determination of the geographic scope of any of the rate groups, "well, to the extent it reflects density then it's implicit in that, I believe."

Further, on cross-examination, BellSouth witness Cox admitted that BellSouth's process of deciding which rate groups to place in which zone was a fairly subjective process.

During cross-examination, BellSouth witness Cox explained that under BellSouth's proposal, UNE rates would generally be higher in the rural areas and lower in the urban areas of the State.

On redirect, witness Cox agreed that under the New Entrants' geographic deaveraging proposal, 96.13% of the lines in North Carolina would fall in three zones and that the New Entrants' proposed Zones 1, 5, and 6 account for 3.87% of the lines in North Carolina. Further, witness Cox agreed that under Sprint's geographic deaveraging proposal, 99% of the lines would fall in five zones with Zones 1, 2, 9, and 8 covering about 1.1% of the lines in the State. Witness Cox also agreed that under BellSouth's proposal, 76% of BellSouth's customers are in Zone 1 which would have the lowest unbundled loop rate and that other than the Public Staff, no other Party presented a geographic deaveraging proposal which would include as many customers in the lowest unbundled loop rate zone. On recross to the redirect, witness Cox admitted that under the Sprint geographic deaveraging proposal, 43% or 44% of the customers would have a rate substantially lower by at least three dollars than BellSouth would have for its customers in its proposed Zone 1.

NCCTA stated in its Brief that by BellSouth's own admission, its approach of using rate groups is not one which is based on underlying costs but instead is based on the preservation of existing retail rate distinctions.

Sprint witness Hunsucker stated in direct testimony that BellSouth's geographic deaveraging proposal should be dismissed as not permissible under TA96 or the FCC's Rules since its proposal to use wire centers by rate groups is not cost-based.

Sprint witness Hunsucker stated in direct testimony that there are a number of reasons to support the use of wire centers. First, witness Hunsucker stated, the wire center generally conforms to the market definitions and plans of new entrants, and therefore averaging prices at this level is not likely to distort their entry or marketing decisions. Second, witness Hunsucker explained, geographic deaveraging loop prices below the wire center entails not only more complex cost modeling but would impose significant additional costs on both ILECs and CLPs in administering that rate structure. Finally, witness Hunsucker argued, geographic deaveraging loop prices above the wire center and at the exchange level results in excessive averaging.

Sprint witness Hunsucker further noted in rebuttal testimony that he had reviewed the geographic deaveraging proposal of the Public Staff. Witness Hunsucker stated that the Public Staff's proposal is based on the costs filed in the universal service proceeding in North Carolina. Witness Hunsucker stated that Sprint filed its costs by wire center in this proceeding and believes that the results of its filing are more appropriate than the extrapolation process used by Public Staff witness Garrison. Further, witness Hunsucker noted that the Commission should not be bound to an absolute three zone approach but should adopt Sprint's plus or minus 20% approach as appropriate for all ILECs in North Carolina.

Verizon witness Steele argued in direct testimony that UNE costs should be calculated at a wire center level.

NCCTA stated in its Brief that it agrees with the New Entrants, Sprint, and WorldCom that UNEs should be deaveraged at the wire center level. But, NCCTA maintained, it believes that there are practical and administrative advantages to a streamlined approach to geographic deaveraging which favors adoption of a maximum of three deaveraged zones for each ILEC.

New Entrants witnesses Starkey and McPeak stated in direct testimony that the method of geographic deaveraging should vary based on the UNE involved. Witnesses Starkey and McPeak gave an example of "wire centers" stating that they are discrete network locations that have been specifically constructed to house a collection of outside plant facilities (primarily loops) that are served by common central office equipment. Therefore, witnesses Starkey and McPeak concluded, a wire center serves as the most rational starting point of any geographic deaveraging proposal designed to recognize geographically disparate costs associated with provisioning outside plant facilities.

Public Staff witness Garrison stated in direct testimony that under Verizon's proposal, the Company would have an incentive to charge higher retail rates for the Bennett wire center than for the other Durham wire centers because those wire centers [Bennett and Durham] would be in different UNE zones. Witness Garrison also noted that under the New Entrants' proposal, BellSouth would have an incentive to charge higher retail rates for the Garner wire center than for the other Raleigh wire centers because those wire centers [Garner and Raleigh] would be in different UNE zones.

The Commission does not believe BellSouth's proposed methodology of basing zones on BellSouth's existing rate groups is appropriate. The Commission agrees with NCCTA and Sprint that basing UNE geographic deaveraging zones on rate groups is not appropriate since rate groups were formed to include exchanges with similar calling scopes, and <u>not</u> costs, in the same rate group.

Further, the Commission understands that the Public Staff's position to establish zones on the exchange level is based on a belief that if geographic deaveraging is not done on the exchange level, exchanges within the same area could be in different UNE zones. The Public Staff apparently believes that this would put pressure on the ILEC to charge higher retail rates in one exchange than in another exchange which is located close by.

However, the Commission agrees with the assertions made by the New Entrants, WorldCom, and AT&T that wire centers are the most logical starting point for any geographic deaveraging methodology designed to recognize geographically disparate costs associated with provisioning outside plant facilities such as loops and subloops.

Additionally, the Commission agrees with Sprint witness Hunsucker who stated in direct testimony that geographic deaveraging loop prices above the wire center level or at the exchange level, results in excessive averaging. As witness Hunsucker testified, the average cost of loops within exchanges can deviate significantly from the costs of loops in individual wire centers within an exchange.

The Commission also notes that the Public Staff stated in its Proposed Order that it is not strongly opposed to geographic deaveraging rates by wire center. But, the Public Staff stated, it believes the most desirable procedure is to deaverage by exchange.

The Commission agrees with NCCTA, the New Entrants, Sprint, Verizon, WorldCom, and AT&T that establishing zones should be accomplished at the wire center level by grouping wire centers. The Commission believes that the record of evidence best supports grouping wire centers rather than rate groups or exchanges when determining geographic deaveraging zones.

CONCLUSIONS

The Commission concludes that geographic zones should be established at the <u>wire center level</u> by grouping wire centers.

<u>EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6</u>

<u>ISSUE NO. 6</u>: Should the degree of geographic deaveraging be uniform <u>for all UNEs and UNE combinations</u> for which the Commission requires geographic deaveraging?

POSITIONS OF PARTIES

BELLSOUTH: Yes. The degree of geographic deaveraging should be uniform for all deaveraged UNEs and UNE combinations.

CAROLINA/CENTRAL/SPRINT: No. Network element rates should be geographically deaveraged to the degree necessary to avoid significant deviations between the rate charged for a network element and the actual forward-looking costs of providing that element in a defined geographic area. However, because different network elements have differing cost disparities across the same geographic areas, the number of zones appropriate for the geographic deaveraging of one element is not necessarily the appropriate number of zones for geographic deaveraging another network element.

NCCTA: Yes. The degree of geographic deaveraging should be uniform for all deaveraged UNEs and UNE combinations.

NEW ENTRANTS: No. It is not necessary that the degree of geographic deaveraging be uniform among all UNEs.

PUBLIC STAFF: Yes. The degree of geographic deaveraging should be uniform for all UNEs and UNE combinations.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. Verizon did not specifically address the issue of uniform geographic deaveraging for all UNEs, but since Verizon is only recommending geographic deaveraging the local loop, the issue of uniform UNE geographic deaveraging would be moot.

WORLDCOM AND AT&T: No. It is not necessary that the degree of geographic deaveraging be uniform among all UNEs. UNEs should be geographically deaveraged to the degree necessary to avoid significant deviations between the rate that is charged for a UNE and the forward-looking costs of providing that element in a defined area.

DISCUSSION

BellSouth noted in its Proposed Order that this issue concerns whether it is appropriate for the Commission to adopt a geographic deaveraging methodology which assigns the same number of zones to each UNE. BellSouth stated that there is no evidence in the record that it is necessary to have a different number of zones for each UNE. BellSouth stated that if the number of zones is not uniform among all UNEs, then the complexity that arises from having an excessive number of zones is dramatically increased.

New Entrants witness Starkey stated in direct testimony that it is not necessary that the degree of geographic deaveraging be uniform amongst UNEs.

In their Proposed Order, the New Entrants maintained that it is not necessary for the degree of geographic deaveraging to be uniform among all UNEs, since application of the geographic deaveraging methodology proposed by the New Entrants may produce varying results for each UNE as a result of the ILEC's respective cost data.

The Commission finds it appropriate to adopt a geographic deaveraging plan which deaverages all UNEs uniformly (i.e., applies the same number of zones to each UNE). The Commission does not believe that Sprint's position on this issue is necessarily incorrect (i.e., that because different network elements have differing cost disparities across the same geographic areas, the number of zones appropriate for the geographic deaveraging of one element is not necessarily the appropriate number of zones for geographic deaveraging another network element). However, the Commission agrees with BellSouth that not applying the number of zones uniformly to each UNE would increase the complexity of a geographic deaveraging plan. Therefore, the Commission believes that it is appropriate for the Commission to uniformly deaverage all UNE rates into the same number of zones.

CONCLUSIONS

The Commission concludes that it is appropriate to deaverage all UNEs to the same degree by applying the same number of zones.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

ISSUE NO. 7: Should the degree of geographic deaveraging be uniform for all ILECs for which deaveraged rates are required by the Commission?

POSITIONS OF PARTIES

BELLSOUTH: Yes. The degree of geographic deaveraging should be uniform for all ILECs for the deaveraged rates set by the Commission.

CAROLINA/CENTRAL/SPRINT: No. The number of zones appropriate for a network element provided by one ILEC is not necessarily the appropriate number of zones for that same element provided by another ILEC because the geographic disparity in the cost of providing an element may be substantially more or less for one ILEC versus another.

NCCTA: Yes. The degree of geographic deaveraging should be uniform for all ILECs for the deaveraged rates set by the Commission.

NEW ENTRANTS: No. It is not necessary that each ILEC geographically deaverage UNE rates to the same extent. While the same geographic methodology should be applied to all ILECs, it is not necessary that each ILEC deaverage rates to the same extent as other ILECs. It is possible that the costs incurred by each ILEC will differ to varying degrees therefore, some ILECs may be required to deaverage their rates to a greater extent than other ILECs.

PUBLIC STAFF: Yes. The degree of geographic deaveraging should be uniform for all ILECs for the deaveraged rates set by the Commission.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. However, if the Commission decides further geographic deaveraging is necessary, the Commission should establish only three zones for Verizon. Verizon does not take a position as to whether the Commission should create additional zones for the other ILECs.

WORLDCOM AND AT&T: No. It is not necessary that each ILEC geographically deaverage UNE rates to the same extent. The number of zones appropriate for a UNE provided by one ILEC, however, is not necessarily the appropriate number of zones for that same element as provided by another ILEC.

DISCUSSION

BellSouth argued in its Proposed Order that the manner in which UNEs are deaveraged and the designation of zones should apply equally to all ILECs. BellSouth argued that from a practical standpoint, it is appropriate to apply the same geographic deaveraging methodology with the same number of zones equally to each ILEC.

New Entrants witness Starkey stated in direct testimony that it is not necessary that each ILEC deaverage rates to the same extent as other ILECs.

In their Proposed Order, the New Entrants argued that generic rules requiring uniform geographic deaveraging among ILECs are likely only to detract from the overarching objective of more closely aligning UNE rates with underlying costs.

NCCTA witness Barta stated in direct testimony that there should be consistency in the manner in which the three non-rural ILECs deaverage UNEs across their service territories. Witness Barta recommended that the Commission require BellSouth to assign wire centers to three geographic zones using the same methodology recommended for Verizon.

NCCTA witness Barta argued in direct testimony that Sprint's geographic deaveraging proposal is not preferable since it is based on more than three zones. Witness Barta argued that the use of more than three zones introduces unnecessary planning, marketing, and administrative burdens upon CLPs. Witness Barta recommended that if the Commission adopts Sprint's methodology, it should limit its adoption to Sprint only and not impose the methodology upon Verizon or BellSouth.

The Public Staff's proposal divides the State into three geographic zones based on the costs established for universal service using inputs approved in Docket No. P-100, Sub 133b (the forward-looking economic cost [FLEC] docket). To accomplish this, the Public Staff grouped all exchanges in the State for all LECs into three zones based on their costs as compared to the statewide average. The Public Staff then determined the relationship of each LEC's average cost per access line for each zone to its statewide average cost. The Public Staff then took this percentage and applied it to the LEC's average UNE cost to arrive at deaveraged UNE rates.

Sprint stated in its Proposed Order that the geographic disparity in the cost of providing a UNE may be substantially more or less for one ILEC versus another ILEC.

WorldCom witness Darnell testified that under FCC Rule 51.507(f), the Commission is required to deaverage each ILEC's rates in this case. Witness Darnell asserted that the three-zone requirement of Rule 51.507(f) applies on a per-ILEC, per-state basis.

The Commission believes that it is appropriate for the Commission to determine that the degree of geographic deaveraging should be uniform for all ILECs for which deaveraged rates are required. While the Commission believes that there are geographic cost differences for UNEs between ILECs, the Commission does not believe that a uniform geographic deaveraging plan for all ILECs would create unreasonable results. Further, the Commission agrees with BellSouth that from a practical standpoint, it appears appropriate to apply the same geographic deaveraging methodology and zones to each ILEC uniformly. Therefore, the Commission concludes that it is appropriate to apply the same geographic deaveraging methodology and zones to all ILECs uniformly.

CONCLUSIONS

The Commission concludes that it is appropriate to apply the same geographic deaveraging methodology and zones to all ILECs uniformly.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

ISSUE NO. 8: What other factors or policy considerations, if any, should be considered in determining deaveraged UNE rates (e.g., universal service impact, stimulation of competition, retail rates, public policy, and/or company size)?

POSITIONS OF PARTIES

BELLSOUTH: When establishing deaveraged rates, the Commission should consider the geographic markets that currently exist in the State, the proximity and relationship of customers to each other, and the need to treat similarly situated customers in a consistent manner. Local service retail rates have been established in an inverse relationship to costs, and geographic deaveraging of UNE rates exacerbates the mismatch between prices and costs which will, in turn, have the effect of allowing a more rapid reduction of the implicit subsidies that are received from low cost urban areas and that support service in high cost rural areas.

CAROLINA/CENTRAL/SPRINT: The mandate of Congress and the FCC to geographically deaverage UNE rates is not "tied" to other factors or policy considerations such as impact on universal service or retail rate structures. The Commission should address such related factors in other proceedings, i.e., price regulation, rate rebalancing, or universal service — but they are not relevant to the issue of geographic deaveraging in this proceeding.

NCCTA: As recognized by the FCC, the requirement to deaverage is independent of universal service and other related concerns.

NEW ENTRANTS: Geographic deaveraging of UNE rates should not be delayed pending the Commission's decisions on universal service and retail rate rebalancing. However, public policy does require that network elements be geographically deaveraged to a sufficient degree to provide incentives for competition in North Carolina.

PUBLIC STAFF: The Commission cannot consider the geographic deaveraging issue in a vacuum; a responsible decision-making agency must take into account the consequences of its rulings. It seems clear that UNE rate geographic deaveraging is likely to have both positive and negative effects. It will enable many CLPs to provide service in urban areas at a lower cost, and ILECs will have an incentive to reduce business rates in these areas to meet the increased competition. As a result, urban businesses will benefit from lower rates. On the other hand, geographic deaveraging is unlikely to promote the spread of competition to areas where it does not now exist, and, in fact, may well create pressure for increased rates in these areas. Proposals for a state universal service fund are pending before the Commission, and Public Staff witness Garrison's testimony shows that geographic deaveraging is likely to bring about a substantial increase in the size of any such fund. It also appears that geographic deaveraging is likely to result in increased administrative costs for ILECs and CLPs. The Commission is clearly entitled to take into account the probable effect of geographic deaveraging, both favorable and unfavorable, in deciding on whether UNE rates should be deaveraged in this case, the extent to which they should be deaveraged, and the procedure to be followed in geographic deaveraging.

VERIZON: UNE rates, retail rates, and universal service are inextricably linked. Further, geographically deaveraging UNE rates without removing implicit support from retail rates would only exacerbate the anticonsumer and anticompetitive effects of geographic deaveraging.

WORLDCOM AND AT&T: Geographic deaveraging of UNE rates should not be delayed pending the Commission's decisions on universal service and retail rate rebalancing. The impact on competition should be considered in determining deaveraged UNE rates. Proper geographic deaveraging of UNE rates will help facilitate competition in the local telecommunications market in North Carolina by providing proper signals and incentives to potential market entrants.

DISCUSSION

BellSouth witness Cox testified that rates for certain services have historically been set well above cost in order to provide support for other services, for example, business rates and vertical features have subsidized residential service, which has generally been priced below cost. Additionally, witness Cox stated that retail rates for basic residential and business service have traditionally been set on the basis of calling scope. Witness Cox maintained that this policy has provided additional support for below-cost service to rural customers. She noted that implicit subsidies of this type are not found in UNE rates. Witness Cox observed that up to now, UNE rates have been uniform throughout the State, but she stated that after geographic deaveraging, they will be higher in rural areas than they will be in urban areas. Therefore, witness Cox concluded, geographic deaveraging will create an inverse relationship between retail rates and UNE rates. Witness Cox maintained that because of the different ways in which ILEC and CLP rates are set, CLPs have been able to compete with ILECs very successfully for urban business customers for some time, and they will be able to do so even more successfully as a result of geographic deaveraging. Witness Cox recommended that, in order to allow ILECs and CLPs to compete on a more even basis, the Commission should encourage rate rebalancing and establish a universal service fund in the near future.

Sprint witness Hunsucker recommended that the Commission not attempt to deal with issues such as the effect of geographic deaveraging on competition, retail rates, or universal service in this proceeding. Witness Steele maintained that while the Commission can properly consider the administrative costs of geographic deaveraging in this case, it should deal with policy issues in future proceedings. Witness Steele stated that in this case, the Commission should simply focus its attention on complying with the requirement of FCC Rule 51.507(f) that deaveraged UNE rates should be established. Witness Hunsucker testified that under Section 252 of TA96, rates for UNEs must be cost-based, and the FCC Rules define "cost-based" to mean based on forward-looking economic costs. Witness Steele argued that the Commission has already established UNE rates for the State's major ILECs, based on each ILEC's statewide average costs. However, the costs of providing certain UNEs vary substantially over the service territory of a given ILEC. In particular, the average cost of providing analog two-wire local loops in a given wire center in Sprint's service area varies from as low as $9.30 to as high as $81.89. Under these circumstances, witness Hunsucker stated, the use of statewide average rates for local loops would violate the requirement for cost-based rates and would send incorrect price signals to CLPs in connection with their decision whether to purchase UNEs from the ILEC or to build their own facilities.

On cross-examination by BellSouth, Sprint witness Hunsucker agreed that administrative issues should be considered when adopting a geographic deaveraging plan. Witness Hunsucker explained that Sprint proposed the plus or minus 20% rule, wherein a LEC may group wire centers, switches, and routes into a single rate group so long as the price of a single wire center, switch, or route does not vary from the weighted averaged price for the group by more than 20%, to account for administrative difficulty.

Verizon witness Steele testified that there are strong policy reasons weighing against any geographic deaveraging of UNE rates until a universal service fund is established and retail rates are rebalanced. Witness Steele observed that at present, ILEC retail rates are not cost-based. Witness Steele stated that instead, they reflect the complex system of implicit subsidies that has been developed over many years. Witness Steele explained that rates for business and vertical services have been set well in excess of the cost of these services, in order to support below-cost rates for residential service. In addition, witness Steele noted, when rates are set on a statewide average basis, customers in low-cost areas provide support for those in high-cost areas. Witness Steele stated that because CLPs are able to set their rates at cost-based levels, without any need to have some customers provide implicit support for others, they already have a substantial competitive advantage in serving business customers in low-cost areas. Witness Steele maintained that their advantage will be even greater if they are able to acquire UNEs in low-cost areas at deaveraged rates rather than statewide average rates. Witness Steele argued that in high-cost areas, on the other hand, geographic deaveraging will provide no incentive for CLPs to begin offering service; it will only serve to increase the UNE rates above their existing levels. In light of these concerns, witness Steele recommended that the Commission not deaverage rates in this case. Witness Steele further recommended that even if the Commission elects to create deaveraged rate zones for the State's other ILECs, it should allow Verizon to operate as a single zone with statewide average UNE rates. Witness Steele also presented a proposal for three deaveraged rate zones, to be used in the event the Commission concludes that Verizon's rates must be deaveraged.

New Entrants witnesses Starkey and Gose strongly supported Sprint's position that UNE rates for each of the ILECs must be deaveraged. Witness Starkey stated that fully cost-based rates are far more economically efficient than traditional telephone rates, and the long-term social benefits produced by an efficient, fully competitive rate system will greatly outweigh any harmful short-term consequences. However, witness Starkey maintained, rates cannot be economically efficient until they are fully cost-based, and they cannot be fully cost-based until they are deaveraged. Witness Starkey argued that until rates for UNEs are deaveraged, they will inevitably give rise to economic distortions and perverse incentives, particularly in connection with a CLP's decision whether to acquire UNEs or build its own facilities. Witness Starkey asserted that full-scale, statewide competition is not likely to arise until three objectives have been met: the development of cost-based, deaveraged UNE rates; the rebalancing of retail rates to eliminate implicit subsidies; and the establishment of a universal service fund. Witness Starkey argued that the Commission cannot put off each of these goals until the others have been accomplished; it must move forward with each of them, and it must proceed with geographic deaveraging in this case. According to witness Starkey, in any case of doubt the Commission should lean toward a greater rather than lesser degree of geographic deaveraging, because extensive geographic deaveraging is necessary if rates are to reflect costs accurately.

During cross-examination, witness Starkey stated that if you deaverage UNEs and allow competition to begin to grow, then the Commission will understand what it has to do with universal service in order to make full local competition work. Witness Starkey also admitted that universal service is a factor in geographic deaveraging but that geographic deaveraging should not be held up to wait for universal service. Witness Starkey explained that competition takes time and that it takes time to erode the subsidies.

The following is an excerpt from the transcript of BellSouth's cross-examination of New Entrants witness Starkey:

> Q. ". . . isn't it true that the only financial consequence directly of adopting your geographic deaveraging proposal is that the loops in the urban areas for the business customers will be driven down in price?"
>
> A. "No absolutely not. I wouldn't agree with that."
>
> Q. "How many loops do you think are going to be bought at the $52.30 range in Zone 6?"
>
> A. "I think there could be a significant number of them, because what you can't do is you can't look at the market as static and say, 'Today we don't have a universal service system in place that allows competitive access to explicit subsidies, and hence, we shouldn't talk about deaveraging unbundled loop rates.' As I say in my testimony and I said in my summary, these are two objectives you have to pursue. And you have to pursue them at the same time. But holding out one and saying, 'We don't have this yet, so we can't do that,' just doesn't make any sense. You've got to do them both together. So to the extent that this Commission can, and I assume will, derive a universal service system that allows for affordable telephone service, and also explicitly identifies those subsidies so they can be available to competitors, can pursue both of those objectives equally. And I think you will see some purchasing of those higher cost loops if the competitive market place is structured as efficiently as that."

NCCTA witness Barta argued in his summary that the attention on the real issue in this proceeding should not be diverted because of some Parties' claims that geographic deaveraging of UNE rates will lead to the collapse of the provision of basic telecommunications services to the average residential customer. Witness Barta argued in his summary that rate rebalancing and universal service are not a part of the instant docket and may be important matters but should be addressed in a separate proceeding.

Public Staff witness Garrison stated in direct testimony that the Commission faces both immediate and long-term considerations in this docket. Witness Garrison stated that the purpose of geographic deaveraging is to stimulate competition which geographic deaveraging will do for the areas already experiencing competition. However, he asserted, public policy favors the development of competition throughout the State, not just in select areas. Witness Garrison stated that since first receiving certification in 1996, CLPs have tended to offer their services only in the most urban areas of the State and principally to serve only business customers. Witness Garrison argued that if UNE rates are deaveraged and set at higher levels in rural areas than in urban areas, the incentive for CLPs to serve rural areas will be further reduced. Witness Garrison maintained that any geographic deaveraging will likely have a negative, rather than a positive, impact on the prospects that the rural, insular, and high costs areas will be served by CLPs using UNEs and that the greater the degree of geographic deaveraging, the greater the negative impact on those prospects.

Witness Garrison further noted in direct testimony that geographic deaveraging will likely lead to corresponding changes in the retail rates of the ILECs. He argued that if UNE rates are deaveraged at the wire center level, as proposed by the New Entrants, Sprint, and Verizon, the ILECs will be pressured by market forces to charge different rates in those multi-wire center exchanges having different UNE rates. Witness Garrison noted that after geographic deaveraging of UNE rates, ILECs would have an incentive not only to decrease retail rates in the urban exchanges where deaveraged UNE rates are lower, but to increase retail rates in the rural exchanges where deaveraged UNE rates are higher.

Witness Garrison suggested that another consideration for geographic deaveraging is the administrative complexity of implementing the chosen geographic deaveraging methodology. Witness Garrison noted that the greater the amount of geographic deaveraging, the greater the complexity of the administrative and billing systems the ILECs and CLPs must put in place.

The Commission believes that in order to be in compliance with FCC Rule 51.507(f), the Commission must adopt a plan to geographically deaverage UNE rates in this docket. However, the Commission does not believe that it should adopt such a plan without acknowledging that there could be potential negative impacts on retail rates and universal service after adoption of a geographic deaveraging plan. The Commission believes that it would be appropriate for the Commission to adopt a geographic deaveraging plan in the instant proceeding and consider any impacted issues such as retail rates and universal service in future proceedings after some time has elapsed and the Commission is able to determine the effects of imposing its geographic deaveraging plan.

CONCLUSIONS

The Commission concludes that in order to be in compliance with FCC Rule 51.507(f), the Commission must adopt a plan to geographically deaverage UNE rates in this instant docket. However, the Commission does not believe that it should adopt such a plan without acknowledging that there could be potential negative impacts on retail rates and universal service after adoption of a geographic deaveraging plan. The Commission believes that it would be appropriate to adopt a geographic deaveraging plan and consider any impacted issues such as retail rates and universal service in future proceedings after some time has elapsed and the Commission is able to determine the effects of imposing its geographic deaveraging plan.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

ISSUE NO. 9: What are the appropriate rates for those UNEs and UNE combinations that a Party proposes to be deaveraged? **COMMISSION NOTE:** A more pertinent description of this issue would be: What is the appropriate methodology for the formation of zones to geographically deaverage UNE rates?

POSITIONS OF PARTIES

BELLSOUTH: First, under BellSouth's geographic deaveraging proposal, loop investments by wire center must be developed. BellSouth's methodology produces three rate zones which correspond to BellSouth's rate groups and the statewide average UNE costs in the following manner:

Zone 1 (Rate Groups 7-10):	84.42% of the statewide average cost
Zone 2 (Rate Groups 5-6):	143.25% of the statewide average cost
Zone 3 (Rate Groups 1-4):	166.14% of the statewide average cost

CAROLINA/CENTRAL/SPRINT: For all ILECs operating in North Carolina, the Commission should find it appropriate to geographically deaverage local loops, subloops, local switching ports and local switching usage, tandem switching, shared and dedicated transport, and dark fiber network elements according to the following procedure: (1) the wire center, switch, or route specific prices for each network element to be deaveraged should be taken from a cost study employing the costing methodology used by Sprint in its cost study; and (2) the individual prices should then be grouped or banded such that the actual price of each wire center, switch, or route in the band does not deviate from the banded rate by more than 20%. Minor exceptions to the 20% variation rule should be allowed for reasons of administrative efficiency, provided that they affect only a few elements and do not materially impact rates. For the two Sprint North Carolina ILECs, the Commission should find the following deaveraged rate structures to be appropriate:

<u>Deaveraged rate structure for local loops</u> - five analog two-wire local loop rate bands for both Carolina and Central.

<u>Deaveraged rate structure for subloops</u> - six rate bands for both analog two-wire feeder subloops and analog two-wire distribution subloops for both Carolina and Central.

<u>Deaveraged rate structure for local switching</u> - two local switching port rates for Carolina, and two for Central; six rate bands for Carolina's local switching usage, and four for Central's.

<u>Deaveraged rate structure for tandem switching</u> - six tandem switching rate bands for Carolina, and three for Central.

<u>Deaveraged rate structure for shared transport</u> - seven shared transport bands for Carolina, and six for Central.

Deaveraged rate structure for dedicated transport - ten and eight rate bands, respectively, for Carolina and Central DS1 dedicated transport, and eleven and nine bands, respectively, for DS3 dedicated transport.

Deaveraged rate structure for dark fiber - six rate bands for dark fiber loop feeder for Carolina, and four for Central; for dark fiber interoffice transport, seven rate bands for Carolina and four for Central. Sprint's costing of high capacity DS3, OC3, OC12, and OC48 loops incorporates dark fiber feeder rates, adding those rates to flat-rated terminal and dark fiber distribution prices, and thereby deaveraging the geographically cost sensitive portion of these loops.

Deaveraged rate structure for network element combinations - six rate bands for the two-wire loop/basic port combination for Carolina, and five for Central. The deaveraged rates for the other network element combinations, where the loop is the only constituent network element deaveraged, are included on the Companies' network element price sheets.

NCCTA: NCCTA proposed to assign wire centers to geographic zones based on the ratio of average loop cost in the wire center to the statewide average as follows: Zone 1 = wire centers that are 100% or less of the statewide average; Zone 2 = wire centers that are 100% to 200% of the statewide average; and Zone 3 = wire centers that are more than 200% of the statewide average. NCCTA proposed to utilize the costs developed in the UNE docket for this purpose.

NEW ENTRANTS: Sprint's proposed geographically deaveraged rates for loops, subloops, transport facilities, and dark fiber as recalculated by the New Entrants should be adopted as Sprint's permanent geographically deaveraged rates for those network elements. Using the same application of its methodology, Sprint should file geographically deaveraged rates for dark fiber subloop distribution. BellSouth should apply the geographic deaveraging methodology proposed by the New Entrants to the cost studies approved by the Commission in its March 13, 2000 Order to derive permanent deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber. Verizon should apply the geographic deaveraging methodology proposed by the New Entrants to the cost studies approved by the Commission in its March 13, 2000 Order to derive permanent deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber. Costs should be deaveraged by estimating wire center costs and grouping them such that a weighted average rate from any wire center grouping does not deviate from the costs of any wire center by more than 20%. This methodology complies with the statutory and regulatory requirements for geographic deaveraging and should be adopted by the Commission.

PUBLIC STAFF: Rates should be deaveraged only for those UNEs related to the local loop and combinations that include the local loop. The Public Staff's geographic deaveraging proposal wherein the State is divided into three geographic zones based on the costs established for universal service using inputs approved in Docket No. P-100, Sub 133b (the FLEC docket). To do this, the Public Staff recommended grouping <u>all</u> exchanges in the State into three zones based on their costs as compared with the statewide average. The Public Staff recommended then determining a relationship of each ILEC's average cost per access line for each zone to its statewide average cost and then taking that percentage and applying it to the ILEC's average UNE cost to arrive at deaveraged UNE rates.

VERIZON: The Commission should not undertake any further geographic deaveraging as UNE rates are already deaveraged into four zones, one for each of the major ILECs. If the Commission does elect to move forward with UNE geographic deaveraging now, it should adopt Verizon's alternative geographic deaveraging proposal. If the Commission declines to accept Verizon's alternative geographic deaveraging proposal, then the Commission should adopt the Public Staff's recommendation as a reasonable compromise.

WORLDCOM AND AT&T: Sprint's proposed geographically deaveraged rates for loops, subloops, transport facilities, and dark fiber should be adopted as Sprint's geographically deaveraged rates for those network elements. Using the same application of its methodology, Sprint should file geographically deaveraged rates for dark fiber subloop distribution. BellSouth should apply the geographic deaveraging methodology proposed by WorldCom and AT&T to the cost studies approved by the Commission in its March 13, 2000 Order to derive deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber. Verizon should apply the geographic deaveraging methodology proposed by WorldCom and AT&T to the cost studies approved by the Commission in its March 13, 2000 Order to derive deaveraged rates for unbundled loops, subloops, transport facilities, and dark fiber.

DISCUSSION

To provide guidance on how state commissions should establish zones for geographic deaveraging, the FCC promulgated Rule 51.507(f) which states:

> State commissions shall establish different rates for elements <u>in at least three defined geographic areas</u> within the state to <u>reflect geographic cost differences</u>.
>
> > (1) To establish geographically-deaveraged rates for elements in at least three defined existing density-related zone pricing plans described in §69.123 of this chapter, or other such cost-related zone plans established pursuant to state law.
> > (2) In states not using such existing plans, state commissions must create a minimum of three cost-related rate zones. [emphasis added]

After BellSouth developed its three zones based on its existing rate groups, BellSouth calculated the average loop investment for each rate zone and compared the zone average to the statewide average. BellSouth stated that the calculations showed that the average loop cost in Zone 1 was 84.42% of the statewide average cost, while the average costs for Zones 2 and 3 were 143.25% and 166.14% of the statewide average, respectively. BellSouth then applied these ratios to the statewide average rate for each UNE to arrive at deaveraged rates.

Sprint maintained that in order to effectuate the requirements of Rule 51.507(f), the Commission should conclude that the actual cost of providing a network element anywhere within the State or within a geographically defined area should be no greater than 20% (plus or minus) of the network element's average price. Sprint argued that the Commission should order all North

Carolina ILECs to deaverage network element prices into cost-based zones using Sprint's proposed criteria.

On cross-examination, Sprint witness Hunsucker stated that in the instances where Sprint proposed two zones, it does comply with FCC Rule 51.507(f). He opined that the FCC Rule can be interpreted to mean that based on cost variances, three zones is the minimum. Witness Hunsucker argued that the Rule mandates deaveraging the geographic zones based on cost and if there is not a cost relationship which warrants geographic deaveraging, it should not be undertaken.

In discussing the plus or minus 20% rule on cross-examination, witness Hunsucker explained that Sprint used the 20% to go through the banding process and that since the 20% generated no more than 11 zones, Sprint believed that 20% was a reasonable number that it could administer efficiently. Witness Hunsucker noted that he did analyze the effect of a 10% rule which revealed that the number of bands would double to 20 to 25 bands for some transport elements. Witness Hunsucker further stated that Sprint did not analyze the results for any percentage above 20%.

Sprint witness Hunsucker stated in rebuttal testimony that apparently the New Entrants believe that Sprint's proposed plus or minus 20% is reasonable as nowhere in their testimony do they challenge the assumption of a plus or minus 20% banding guideline.

Verizon stated in its Proposed Order and Brief that if the Commission determines that further geographic deaveraging should be done, then the Commission should establish only three zones for Verizon. Verizon recommended that the Commission adopt its zone proposal. Verizon's proposal is as follows: all wire centers in which the average loop cost is less than the statewide average loop cost of $24.04 should be mapped to Zone 1 (0% - 100%). All wire centers in which the average loop cost is between the statewide average and approximately 150% of the statewide average should be mapped to Zone 2 (100% - 150%). All wire centers in which the average loop cost is 150% or greater than the statewide average should be mapped to Zone 3 (greater than 150%).

New Entrants witnesses Starkey and Gose testified that they were largely in agreement with the geographic deaveraging methodology proposed by Sprint. They argued that the Sprint proposal brings about a greater degree of geographic deaveraging and thus allows a better matching of rates with costs than the other Parties' proposals, because it deaverages a larger number of UNEs and provides for a larger number of rate zones. In addition, witnesses Starkey and Gose asserted, Sprint's plan avoids artificial groupings of wire centers and has a more objective basis than the methods proposed by other Parties, due to Sprint's policy of not allowing more than a 20% difference between the zone-wide average price of a UNE and actual UNE costs for any wire center within the zone. However, the New Entrants disagreed with Sprint's decision to allow occasional departures from the 20% criterion in the interest of ease of administration and contended that the 20% rule should be applied without exception. With this modification, according to the New Entrants, the Commission should use Sprint's method to deaverage rates for BellSouth and Verizon. Witness Starkey offered in evidence a calculation of deaveraged rates for loops for BellSouth, using Sprint's procedure.

Witness Starkey further testified on cross-examination that one should not begin the geographic deaveraging process by first establishing the number of zones. Witness Starkey advocated a methodology wherein the costs of UNEs are examined and zones are established based on a rational, natural break. Witness Starkey stated that he did not believe that three zones was sufficient to meet the FCC's policy of geographic deaveraging in North Carolina.

Witness Starkey agreed that three of the New Entrants' proposed six zones affect 96.22% of the access lines in North Carolina. However, witness Starkey noted that this result is not that different than the BellSouth and Public Staff proposals. Witness Starkey noted that BellSouth's Zone 1 impacts 76% of the entire State and that the New Entrants do not believe that if you have one zone that impacts 76% of the access lines that very much geographic deaveraging has occurred.

WorldCom witness Darnell endorsed Sprint's geographic deaveraging proposal and recommended that Sprint's method be used to deaverage rates for BellSouth and Verizon.

WorldCom witness Darnell argued in his direct testimony that first the Commission must establish nonrecurring and recurring rates for UNEs under consideration in this proceeding in accordance with the FCC's pricing rules. Under cross-examination by BellSouth, witness Darnell explained that WorldCom believes that the permanent UNE rates established by the Commission in 2000 do not comply with the Act. He argued that the ILECs' cost studies are not based on total element long-run incremental cost (TELRIC). Witness Darnell testified that the only item that can be considered by the Commission in determining deaveraged UNE rates is the FLEC differences caused by different geographic areas. Witness Darnell stated that WorldCom objects to BellSouth's proposed geographic deaveraging methodology because it is in violation of the FCC's Rules. Witness Darnell stated that Verizon's geographic deaveraging proposal does comply with the letter of the FCC's Rules, however, he asserted that the Commission should not adopt Verizon's proposal because the Commission should strive to do more than just comply with the letter of the FCC's Rules. Witness Darnell recommended that the Commission adopt Sprint's proposed geographic deaveraging methodology and apply it to BellSouth and Verizon.

Further, on cross-examination, witness Darnell stated that the Public Staff's proposed methodology is a good foundation but does not go quite far enough. Witness Darnell stated that the Public Staff's recommendation basically puts all of BellSouth in one zone and that it really does not deaverage BellSouth's rates. Witness Darnell further stated that he agreed with the Sprint proposal from a foundation standpoint. However, witness Darnell disagreed with Sprint that geographic deaveraging should apply to other facilities besides the loop such as switching.

NCCTA stated in its Brief that UNE cost data should be utilized to deaverage UNE rates. NCCTA argued that the Public Staff proposes to use FLEC cost data to group underlying costs at the exchange level, but NCCTA maintained that the Public Staff offered no real justification for the use of such costs as opposed to the costs developed in the UNE proceeding. NCCTA argued that as the goal in this proceeding is to deaverage UNE rates, UNE costs should be utilized.

NCCTA witness Barta stated in direct testimony that he does not agree with Verizon witness Steele's assessment that geographic deaveraging will foster CLP "cream skimming". Witness Barta stated that deaveraged UNE rates should make it possible for CLPs to reach a wider range of consumers because economies of scale and scope will be available on competitive terms.

Witness Barta further stated in direct testimony that he does not agree with BellSouth's proposed geographic deaveraging proposal. Witness Barta stated that the BellSouth rate group to zone mapping approach results in geographic zones that include wire centers with wide-ranging averaged monthly loop costs.

NCCTA witness Barta endorsed the geographic deaveraging method proposed by Verizon witness Steele; however, he proposed one change in witness Steele's methodology. He suggested that wire centers with loop costs between 100% and 200% of Verizon's statewide average cost (rather than 100% to 150% as witness Steele proposed) be included in the intermediate rate zone and that only those wire centers with loop costs exceeding 200% of the average be assigned to the high-cost zone. Witness Barta objected to Sprint's geographic deaveraging proposal because of its use of more than three zones, contending that this would impose excessive administrative burdens on CLPs. He likewise objected to BellSouth's proposal, contending that the use of zones formed by combining rate groups would result in excessive variations in cost within zones. He recommended that both Sprint and BellSouth be required to follow the Verizon method (with his proposed modification) in geographic deaveraging their UNE rates.

Public Staff witness Garrison described in direct testimony the Public Staff's geographical deaveraging proposal. He noted that the Public Staff calculated deaveraged rates on a statewide basis rather than separately for each ILEC. Witness Garrison further explained that the Public Staff calculated the per line monthly cost of providing universal service for each exchange in North Carolina. Witness Garrison stated that the statewide average universal service cost per access line in North Carolina is $33.73. Witness Garrison stated that the Public Staff then sorted exchanges based on the per line universal service cost. The Public Staff grouped exchanges into three zones as follows:

Zone 1	115% or less of $33.73
Zone 2	116%-160% of $33.73
Zone 3	161% and above of $33.73

On cross-examination, witness Garrison acknowledged that his $33.73 statewide average figure is not limited to the cost of the loop but represents "the whole ball of wax" for universal service as determined in the FLEC docket (Docket No. P-100, Sub 133b). Further, he agreed that the $33.73 represents the average for every wire center for every ILEC in the State. Witness Garrison stated that he did not believe it would be more appropriate to consider loop costs in establishing zones to calculate the deaveraged UNE rates. Witness Garrison stated that the Public Staff believes that it is more appropriate to reflect the overall costs of providing local service in establishing zone designations. Witness Garrison stated that he does not believe that it is more reasonable for the Commission to adopt Sprint witness Hunsucker's proposed methodology wherein the price of the loop is based upon the loop costs only. Witness Garrison stated that the Public Staff's methodology best represents what the Commission should attempt to do by matching the deaveraged rates with the retail rates that the ILECs are charging.

After reviewing the record of evidence, the Commission has several observations. First, the Commission believes that the level of geographic deaveraging adopted should comply with the FCC Rule but not be administratively burdensome to the ILECs and the CLPs in the State. The

Commission agrees with the comments of the Public Staff and NCCTA that geographic deaveraging should appropriately establish UNE rates based on cost differences based on geographic location, but that the degree of geographic deaveraging should be limited enough to be administratively manageable.

The Commission believes that TA96 requires an eventual progression of implicit subsidies to explicit subsidies. However, the Commission is concerned about how this transition takes place and the timeframe for the transition. The Commission believes that it would be wise for the Commission to adopt a certain level of geographic deaveraging at this point and allow time for the geographic deaveraging plan to be placed into effect. The Commission notes that a transition from implicit subsidies to explicit subsidies will not happen overnight and will take time to occur.

The Commission finds it appropriate to adopt the following geographic deaveraging plan:

(1) Only the loop and subloops should be deaveraged.
(2) The Commission should deaverage the local channel below the DS3 level unless opposition is received by April 4, 2001.
(3) Each ILEC should begin with its permanent UNE rates for the loop established by the Commission in March 2000 as the statewide average rate for that UNE.
(4) Each ILEC should divide up its service territory into Zones based on the following bands:
    (a) Zone 1 - All wire centers with UNE costs of 115% or less of the statewide average for that UNE..
    (b) Zone 2 - All wire centers with UNE costs of 115% to 160% of the statewide average for that UNE.
    (c) Zone 3 - All wire centers with UNE costs of 160% or greater of the statewide average for that UNE.

The Commission believes that by breaking down each ILEC's wire centers into these three zones, for which the percentages are those proposed by the Public Staff, cost differences will be reflected and this will comply with the FCC's Rule.

As an example of the Commission's conclusions, the following would be the deaveraged loop rate methodology for BellSouth:

BellSouth's March 2000 permanent 2-wire analog, voice grade loop - service level 1 rate is $15.88.

BellSouth would analyze its wire centers and determine the wire centers with loop costs as follows:

Zone 1 : Loop cost of $18.26 or less
Zone 2 : Loop cost of $18.26 to $25.41
Zone 3: Loop cost of $25.41 or more

The deaveraged loop rate for Zone 1 would be the weighted average loop cost for all of the wire centers included in Zone 1.

The deaveraged loop rate for Zone 2 would be the weighted average loop cost for all of the wire centers included in Zone 2.

The deaveraged loop rate for Zone 3 would be the weighted average loop cost for all of the wire centers included in Zone 3.

CONCLUSIONS

The Commission concludes that wire centers should be grouped into geographic zones as follows:

Zone 1 - All wire centers with a UNE cost of 115% or less of the statewide average for that UNE.

Zone 2 - All wire centers with a UNE cost of 115% to 160% of the statewide average for that UNE.

Zone 3 - All wire centers with a UNE cost of 160% or greater of the statewide average for that UNE.

IT IS, THEREFORE, ORDERED as follows:

1. That BellSouth, Carolina/Central, and Verizon shall refile their geographic deaveraging proposals by April 16, 2001 reflecting the decisions made by the Commission herein. In their filings, each Party should include a one-page summary sheet of the geographically deaveraged UNE rates produced from its revised proposal.

2. That the appropriate definition of geographic deaveraging is as follows: geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs, as opposed to UNE pricing based on a statewide or companywide average. Further, Verizon's proposal that North Carolina is already in compliance with FCC Rule 51.507(f) since it has adopted UNE prices for each of the four major ILECs in the State is hereby rejected.

3. That the following UNEs should be geographically deaveraged:

(a) Loop; and
(b) Subloop.

4. That, not later than April 4, 2001, any Party which disagrees that the local channel below the DS3 level should be geographically deaveraged may make a filing with the Commission stating any reasons for disagreement.

5. That after statewide average rates for subloops are established by the Commission in the near future, BellSouth, Carolina/Central, and Verizon will be instructed to refile their geographically deaveraged subloop rates based on the decisions reached in this Order.

6. That any UNE combination which includes loops or subloops, and possibly local channels below the DS3 level, should be deaveraged.

7. That monthly recurring charges should be deaveraged. Nonrecurring charges should not be deaveraged at this time.

8. That zones to geographically deaverage UNE rates should be established at the wire center level by grouping wire centers.

9. That it is appropriate to deaverage all UNEs to the same degree by applying the same number of zones.

10. That it is appropriate to apply the same geographic deaveraging methodology and zones to all ILECs uniformly.

11. That in order to be in compliance with FCC Rule 51.507(f), the Commission shall adopt a plan to geographically deaverage UNE rates in this docket. However, the Commission acknowledges that there could be potential negative impacts on retail rates and universal service after adoption of a geographic deaveraging plan. The Commission will consider any impacted issues such as retail rates and universal service in future proceedings after some time has elapsed and the Commission is able to determine the effects of imposing its geographic deaveraging plan.

12. That wire centers shall be grouped into zones as follows:

Zone 1 - All wire centers with a UNE cost of 115% or less of the statewide average for that UNE.

Zone 2 - All wire centers with a UNE cost of 115% to 160% of the statewide average for that UNE.

Zone 3 - All wire centers with a UNE cost of 160% or greater of the statewide average for that UNE.

13. That the Public Staff shall review the refiled geographic deaveraging proposals of BellSouth, Carolina/Central, and Verizon and file comments on how the proposals comply with the Commission's Order not later than May 14, 2001.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Commissioner William R. Pittman resigned from the Commission effective January 24, 2001, and did not participate in this decision.

bp031401.01

DOCKET NO. P-100, SUB 133d

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
General Proceeding to Determine	)	ORDER FINALIZING
Permanent Pricing for Unbundled	)	DEAVERAGED UNE RATES
Network Elements	)	AND DENYING ALLTEL'S
	)	MOTION TO DEAVERAGE
	)	NONRECURRING RATES

BY THE COMMISSION: In this Order, the Commission will address in Section I the finalization of geographically deaveraged unbundled network element (UNE) rates and in Section II a Motion filed by ALLTEL Communications, Inc. (ALLTEL) on October 26, 2001 requesting that the Commission deaverage nonrecurring rates.

SECTION I - FINALIZING GEOGRAPHIC DEAVERAGING

BACKGROUND

On March 15, 2001, the Commission issued its Recommended Order Concerning Geographic Deaveraging of Unbundled Network Elements. The Commission made the following Findings of Fact:

1. The appropriate definition of geographic deaveraging is as follows: geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the incumbent local exchange companies (ILECs) of providing UNEs, as opposed to UNE pricing based on a statewide or company-wide average. Further, the Commission rejects Verizon's proposal that North Carolina is already in compliance with Federal Communications Commission (FCC) Rule 51.507(f) since it has adopted UNE prices for each of the four major ILECs in the State and concludes that geographic deaveraging of each ILEC's UNE rates must be undertaken by the Commission to comply with FCC Rule 51.507(f).

2. It is appropriate to geographically deaverage the local loop and subloops. There does not appear to be any controversy that the local channel below the DS3 level should be geographically deaveraged, but the Commission will give Parties the opportunity to make a filing with the Commission by no later than April 4, 2001 outlining any reasons for disagreement.

3. Any UNE combination which includes loops or subloops, and possibly local channels below the DS3 level, should be deaveraged.

4. Monthly recurring charges should be deaveraged. Nonrecurring charges should not be deaveraged at this time.

5. Geographic zones should be established at the wire center level by grouping wire centers.

6. It is appropriate to deaverage all UNEs to the same degree by applying the same number of zones.

7. It is appropriate to apply the same geographic deaveraging methodology and zones to all ILECs uniformly.

8. In order to be in compliance with FCC Rule 51.507(f), the Commission must adopt a plan to geographically deaverage UNE rates in this docket. However, the Commission acknowledges that there could be potential negative impacts on retail rates and universal service after adoption of a geographic deaveraging plan. The Commission will consider any impacted issues such as retail rates and universal service in future proceedings after some time has elapsed and the Commission is able to determine the effects of imposing its geographic deaveraging plan.

9. In order to establish geographically deaveraged UNE rates, wire centers should be grouped into zones as follows:

> Zone 1 - All wire centers with a UNE cost of 115% or less of the statewide average for that UNE.
>
> Zone 2 - All wire centers with a UNE cost of 115% to 160% of the statewide average for that UNE.
>
> Zone 3 - All wire centers with a UNE cost of 160% or greater of the statewide average for that UNE.

On March 30, 2001, Exceptions to the Recommended Order were filed by BellSouth Telecommunications, Inc. (BellSouth), the Public Staff, Verizon South, Inc. (Verizon), and WorldCom, Inc. (WorldCom), by and through its subsidiaries certificated by the Commission, including MCImetro Access Transmission Services, LLC (MCIm). Exceptions were filed on Findings of Fact Nos. 1, 6, 7, 8, and 9 of the Recommended Order.

On April 5, 2001, the Commission issued an Order Requesting Comments on the Exceptions. Initial comments were due on April 27, 2001 and reply comments were due on May 11, 2001.

On August 7, 2001, the Commission issued its Order Addressing Exceptions Filed to Recommended Order Concerning Geographic Deaveraging. In its Order, the Commission denied Motions for Reconsideration on and affirmed Findings of Fact Nos. 1, 6, 7, and 8. The Order contained the following Ordering Paragraph concerning Finding of Fact No. 9:

> That to reflect the decisions herein, Finding of Fact No. 9 is hereby amended to read as follows:
>
> In order to establish geographically deaveraged UNE rates, wire centers should be grouped into zones as follows:

Zone 1 - All wire centers with loop investment of up to 115% of the statewide average.

Zone 2 - All wire centers with loop investment above 115% and up to 160% of the statewide average.

Zone 3 - All wire centers with loop investment above 160% of the statewide average.

Further in its Order, the Commission requested that BellSouth, Carolina Telephone and Telegraph Company and Central Telephone Company (collectively herein referred to as Sprint), and Verizon refile their deaveraging proposal based on the conclusions outlined in the Commission's Order by no later than September 6, 2001.

On September 6, 2001, BellSouth, Sprint, and Verizon refiled their cost studies. By Order dated September 13, 2001, the Commission requested that the Public Staff file comments on the refiled cost studies.

On October 4, 2001, the Public Staff filed its comments on the refiled cost studies. The Public Staff commented on several areas of contention. By Order dated October 9, 2001, the Commission requested BellSouth, Sprint, and Verizon to file a response to the Public Staff's October 4, 2001 Comments.

On October 17, 2001, BellSouth, Sprint, and Verizon filed comments on the Public Staff's October 4, 2001 Comments.

THE PUBLIC STAFF'S OCTOBER 4, 2001 COMMENTS

The Public Staff made the following comments on each ILEC's cost study:

BELLSOUTH: The Public Staff stated that BellSouth's cost study complies with the Commission's August 7, 2001 Order except in the following areas:

1. BellSouth appears to have inadvertently put the Wendell wire center in Zone 3. BellSouth agrees to correct this item.

2. When calculating the deaveraged UNE rates, BellSouth first removed that portion of the rate reflecting the amortization of the nonrecurring cost associated with disconnection. The nonrecurring cost component was then added to the resulting deaveraged rate. This is consistent with the method originally proposed by BellSouth in this docket. The Public Staff stated that it believes the Commission's intent was to deaverage the entire UNE rate, without regard to the individual components within the rate. The Public Staff noted that its conclusion is based on the Commission's discussion of Finding of Fact No. 9 in the March 15, 2001 Order wherein the Commission computed the manner in which the zones would be determined for BellSouth's 2-wire loop. Despite BellSouth's proposal that the nonrecurring amortization component be excluded from the deaveraging calculation, the

Order makes no distinction between that component and the remainder of the UNE rate. Therefore, the Public Staff believes that in calculating its deaveraged rates, BellSouth should reflect the amortization of the nonrecurring cost associated with disconnection along with the other components in the deaveraging calculation.

SPRINT: The Public Staff noted that Sprint included deaveraged rates for the distribution and feeder subloop elements, however, that the Commission has not yet approved statewide average rate for these UNEs. Therefore, the Public Staff believes that it is inappropriate to consider the appropriateness of the deaveraged subloop rates at this time. Further, the Public Staff believes that Sprint's deaveraging proposal complies with the Commission's August 7, 2001 Order with one exception:

1. Sprint did not deaverage all of the components of its proposed rates for ISDN-BRI loops greater than 18,000 feet, DS-0 56/64K loops, and DS-1 loops. The Public Staff noted that it is unclear as to the specific component excluded from the deaveraging calculation, however that it believes that the Commission intended for the entire UNE loop rate to be in the deaveraging calculation regardless of the origin of the component costs. The Public Staff recommended that the Commission require Sprint to recalculate these deaveraged UNE rates by including all of the costs in the deaveraging calculation.

VERIZON: The Public Staff stated that Verizon's cost study complies with the Commission's August 7, 2001 Order except for the following areas:

1. The calculation used by Verizon in determining the average loop investment per wire center does not include all of the loop investment. Instead, Verizon assumes all loops will be 2-wire and calculates the investment accordingly. The Public Staff commented that it has been in contact with Verizon on this issue and that Verizon is in the process of recalculating the loop investment per wire center to reflect the additional investment necessary for 4-wire and other high capacity loops.

2. Similar to BellSouth, Verizon excluded some costs prior to deaveraging its UNE rates. Then, after completing the deaveraging calculation, Verizon added the excluded costs to the resulting rates. The loops costs which Verizon excluded from the deaveraging calculation consist of costs associated with electronics, testing, and common costs. While not every UNE rate included electronics and testing costs, all UNE rates include common costs. Verizon's proposal differs from the original method it used to determine deaveraged UNE rates. In its original deaveraging proposal, Verizon only excluded common costs from the deaveraging calculation. Consistent with its comments regarding BellSouth's cost study, the Public Staff believes that the Commission intended for the entire UNE loop rate to be in the deaveraging calculation regardless of the origin of the component costs. The Public Staff recommended that the Commission require Verizon to recalculate its deaveraged UNE rates by including electronics, testing, and common costs in the deaveraging calculation. The Public Staff maintained that this will ensure that the entire UNE loop rate is included in the deaveraging calculation by all four companies.

3. Verizon's deaveraging calculation has two primary steps: (1) a determination is made of the average per loop investment in each wire center in order to assign the wire centers to one of the three geographic zones; and (2) once the wire centers are placed in a zone, Verizon calculates the specific cost for each UNE. The Public Staff stated that based on the Commission's discussion for Finding of Fact No. 7 in the March 15, 2001 Order, the Commission intended for the companies to use the same methodology in computing the rates for each zone. The Public Staff noted that BellSouth and Sprint calculated the ratio of each zone's rate to the statewide average using the average loop investment and thus these companies applied the same ratio to the statewide average in calculating the zone rates for all of the UNE loop rates. The Public Staff maintained that Verizon's calculation should be consistent with the approach used by BellSouth and Sprint.

GENERAL: Finally, the Public Staff also made a general recommendation to the Commission due to the widespread interest in deaveraged UNE rates. The Public Staff recommended that the Commission require the Companies to submit their final UNE rates in electronic form along with an electronic listing of the wire centers in each zone.

The Public Staff recommended that all permanent UNE rates which have been approved by the Commission should be included in the listing of rates and that wire center listings should reference both the common English name of the wire center and the CLLI. The Public Staff noted that to maintain consistency, the Commission should require that the UNE rates and listing of wire centers be filed in a format compatible with Excel 95/97.

ILECS' RESPONSES TO THE PUBLIC STAFF'S OCTOBER 4TH COMMENTS

BELLSOUTH: BellSouth noted that after filing its cost study on September 6, 2001, the Public Staff notified BellSouth that its deaveraging factors should be developed using the Benchmark Cost Proxy Model (BCPM), and, accordingly, BellSouth filed its revised deaveraging factors and its proposed deaveraged rates on September 20, 2001.

BellSouth noted that the Public Staff stated in its comments that BellSouth appeared to have inadvertently put the Wendell wire center in Zone 3. BellSouth stated that it concurs with this finding and has agreed to modify its filing by appropriately placing the Wendell wire center in Zone 2.

Concerning the Public Staff's comments that it believes that the Commission's intent was to deaverage the entire UNE rate, without regard to the individual components within the rate, BellSouth stated that it has been directed by previous order of the Commission to recover the disconnect costs associated with loops (and ports) by amortizing the nonrecurring disconnect cost, thereby creating a monthly amount that is added to the monthly recurring loop (and port) cost. BellSouth stated that this method of cost recovery, however, does not negate the fact that the amortized cost is, by nature, a nonrecurring costs, and that the Commission has clearly stated that nonrecurring costs are not to be deaveraged. BellSouth noted that Finding of Fact No. 4 of the Commission's March 15, 2001 Order stated that nonrecurring charges should not be deaveraged at this time. BellSouth asserted that whether a nonrecurring charge is applied "up front" or is recovered on an amortized basis as a monthly recurring charge does not alter the fact that it is a nonrecurring charge. BellSouth noted that no party filed an exception to Finding of Fact No. 4.

BellSouth argued that in its filings in this proceeding, it has made it clear that the amortized disconnect cost was added after the deaveraging factors were applied to the statewide average recurring monthly loop cost and that no party to this proceeding disputed BellSouth's methodology.

BellSouth noted that in its August 7, 2001 Order, the Commission footnoted that the Zone 1 rate of \$12.27 came from Attachment B of BellSouth's March 30, 2001 Exceptions and that Attachment B to that filing clearly showed the formula that resulted in the Zone 1 rate of \$12.27 ((\$15.60 x .7688) + \$.28) = \$12.27. BellSouth argued that because the Commission clearly was cognizant of the development of the \$12.27, BellSouth believes that the Commission does not intend for BellSouth to deaverage the amortized disconnect costs and that indeed, requiring such would be in direct conflict with the Commission's determination that nonrecurring costs are not to be deaveraged.

SPRINT: Sprint stated in its comments that it reviewed the Public Staff's comments and agrees that Sprint prematurely submitted deaveraged rates for distribution and feeder subloop elements and that Sprint will make a later filing withdrawing this information. **[COMMISSION NOTE:** Sprint has not yet made a filing withdrawing the subloop deaveraged rates.]

Sprint maintained that the "adders" (i.e., component costs) which were questioned by the Public Staff are listed separately in Sprint's September 6, 2001 filing, but are already included in the cost calculations for 4-wire, DS-0, and DS-1 loops. Sprint stated that using the geographic deaveraging methodology proposed by the Public Staff for higher capacity loops would cause some exchanges to move from Zone 3 to Zone 2 and others from Zone 2 to Zone 1 for those high capacity loops that include the adder. Sprint maintained that this would result in some high capacity services being classified in one zone while 2-wire loop services are classified in a different zone for the same exchange and would, therefore, be inconsistent with the Commission's August 7, 2001 Order.

Sprint also stated that it believes that it has appropriately deaveraged all components of its proposed rates for ISDN/BRI loops greater than 18,000 feet, DS-0 56/64K loops, and DS-1 loops. Sprint maintained that the adders referenced by the Public Staff cover the costs of electronics needed to provide each of these services and do not vary with geographic location. Sprint argued that to deaverage monthly recurring rates without first removing such adders would be inconsistent with the purpose of geographic deaveraging, would lessen the economic correlation between costs and price, and would be in conflict with the Commission's definition of geographic deaveraging.

VERIZON: Verizon addressed each of the Public Staff's concerns with Verizon's cost study. First, Verizon noted that the Public Staff's comment that Verizon has not yet included its full loop investment in its deaveraging calculation for all loops, was correct. Verizon stated that it is in the process of recalculating its total investment per wire center. Verizon commented that its proposed rate filing included its total loop investment for roughly 97% to 98% of its loops. Verizon maintained that since that filing, it has examined the remaining 2% to 3% of its loops for which the total investment had not yet been calculated. Verizon noted that it has determined that this recalculation will move the Weaverville wire center from Zone 2 to Zone 1, and will move the Micaville and Andrews wire centers from Zone 3 to Zone 2.

Verizon noted that in the Public Staff's second comment, the Public Staff asserted that the manner in which Verizon addresses costs for electronics and testing, as well as common costs, violates the requirements of the deaveraging orders. Verizon commented that the Public Staff claimed that Verizon has excluded costs for electronics, testing, and common costs from its deaveraging calculation. Verizon noted that the Public Staff asserted that this treatment of costs for electronics and testing was a departure from Verizon's earlier submission to the Commission. Verizon asserted that the Public Staff's assertion that it has changed its deaveraging methodology is erroneous. Verizon stated that in its rate filing, consistent with its initial deaveraging proposal, Verizon specifically included the costs of electronics and testing. Verizon argued that these costs do not vary by geography or volume, and therefore, are the same across all wire centers and that the Public Staff appears to confuse this cost uniformity with cost exclusion.

Verizon argued that its treatment of these costs is appropriate and consistent with the Commission's deaveraging orders. Verizon noted that the Commission found in Finding of Fact No. 1 of its March 15, 2001 Recommended Order that geographic deaveraging is the process of pricing UNEs on the basis of regional geographic costs to the ILECs of providing UNEs. Conversely, Verizon contended, the Commission has repeatedly recognized that it is inappropriate to deaverage rates for UNEs such as local channels, transport, dark fiber, and switching absent evidence that costs for those UNEs vary by geography. Verizon maintained that because the direct costs of electronics and testing do not vary by geography, it is inappropriate to deaverage these costs in the manner suggested by the Public Staff. Verizon argued that it is appropriate, however, to include these costs in the TELRIC for the UNE and to set the deaveraged rate at the appropriate TELRIC plus a reasonable allocation of common costs.

Verizon explained that common costs are not direct costs and are not included in Verizon's TELRIC. Rather, Verizon maintained, they are costs that are incurred by Verizon in the provision of UNEs and that the Commission has determined should be allocated equally between and among all CLPs purchasing the same loop UNEs from Verizon. Finally, Verizon also asserted that common costs do not vary by geography. Verizon argued that the Public Staff's interpretation of the deaveraging Orders, however, would ignore the factual information and result in common costs that vary by geography. Verizon asserted that adopting the Public Staff's interpretation that common costs, as with those for testing and electronics, should be deaveraged would have negative policy effects.

Verizon contended that the Public Staff interprets the deaveraging orders as requiring Verizon to deaverage common costs and those for testing and electronics in such a way as to create differences in their rates depending upon which zone they occupy. Verizon noted that the Public Staff referenced Finding of Fact No. 9 as evidence that the Commission intended to deaverage the entire UNE rate, without regard for the cost of the UNE at the zone level. Verizon argued that Finding of Fact No. 9 was aimed solely at determining which wire centers are placed in which zones. Verizon maintained that the Finding of Fact says nothing about how UNEs are priced once the wire center in which they are located is placed in the appropriate zone. Verizon argued that there is nothing in this Finding of Fact that evinces any Commission intent to divorce UNE rates from costs or to create geographic price differences where no corresponding cost difference exists.

Verizon asserted that the Public Staff's interpretation would result in inappropriate public policy. Verizon stated that the negative policy implications can be best demonstrated with an example involving common costs. Verizon maintained that the Commission has set Verizon's uniform common cost for the 2-wire loop at $3.37 in its March 13, 2000 Order and that this cost does not vary by geography and has been uniformly applied to every 2-wire loop UNE sold by Verizon. Verizon argued that the Public Staff's interpretation, however, would deaverage this cost. Verizon noted that while the Commission has determined that $3.37 is the appropriate allocation of common costs for 2-wire loops across the state, the Public Staff would allocate $6.20 of common costs to 2-wire loops sold in the more rural Zone 3. Verizon alleged that it is bad policy to have higher prices in rural areas where those prices are not driven by higher costs. Verizon concluded that the Commission should reject the Public Staff's second comment regarding Verizon's proposed rate filing.

Addressing the Public Staff's third comment on Verizon's cost study, Verizon noted that the Public Staff asserted that Verizon's two-step deaveraging process is contrary to the Commission's deaveraging orders. Verizon maintained that in its first step, it assigns wire centers to each of its three deaveraged zones based on aggregated average loop investment, as required. Verizon stated that in the second step, it calculates the specific TELRIC for each UNE by zone and bases its UNE rates upon that cost plus the common cost as approved by the Commission in its March 13, 2000 Order. Verizon argued that its deaveraging methodology is consistent with the Commission's deaveraging orders and meets each and every requirement set forth in those orders. Verizon commented that the Public Staff, however, interprets the deaveraging orders as requiring Verizon to ignore the zone-specific TELRICs in setting deaveraged rates. Instead, Verizon maintained, the Public Staff believes that the Commission required Verizon to blindly apply an aggregated average ratio based solely on investment in order to set its rates. Verizon contended that although this is the rate-setting method applied by Sprint and BellSouth, mandating its application to Verizon is not supported by the Commission's deaveraging orders, is contrary to established law, and would result in bad policy.

Verizon commented that there are several problems with the Public Staff's interpretation, as follows:

(1) It is based on an aggregated investment ratio for all loop UNEs, and as a result, does not account for investment differences by loop UNE type. Verizon included a footnote that if the Commission determines that the Public Staff's investment deaveraging methodology is, in fact, appropriate for setting rates, Verizon would suggest that it calculate and apply a separate investment ratio for each loop type that would reflect the Company's different investment in each loop type.

(2) The investment method gleaned by the Public Staff does not consider the fact that each investment account has its own, and varying, depreciation life and level of ongoing expenses.

(3) The Public Staff's interpretation would not take into account any of the varying non-investment related costs incurred by Verizon for its different types of loop UNEs. These costs include ongoing costs such as maintenance, as well as any costs that are incurred on a per-activity basis. Clearly, then, the rates resulting from the Public Staff's interpretation of the deaveraging orders would not be cost-based, and would therefore be unlawful.

Verizon argued that once wire centers have been placed in deaveraged zones based on the investment methodology, the deaveraging orders do not require that an ILEC develop its prices based solely on investment, let alone at an aggregated level without regard to loop type.

Verizon maintained that the Commission recognized the limitations in the BCPM cost study used by both Sprint and BellSouth and allowed BellSouth and Sprint to assign wire centers to rate zones based on loop investment at the wire center level. Verizon stated that the Commission has permitted the use of aggregate investment as a zone structuring method in order to accommodate the limitations inherent in the BCPM. Verizon maintained that the Commission could have, but did not, require the use of the aggregate investment method for establishing zone structures in Finding of Fact No. 9. Verizon argued that because it did not do so there, it would be incongruous to apply such a requirement to Finding of Fact No. 7, where issues of costs studies and aggregate investment are not even mentioned.

Verizon asserted that it is beyond doubt that the rates to be set pursuant to the Recommended Order were based on TELRIC and that nothing in the Commission's later Order Addressing Exceptions makes such rates violative of any requirements established by the Commission. Verizon stated that it would be incongruous to transform an accommodation to Sprint and BellSouth into a requirement for Verizon that leads to the creation of rates without any relation to TELRIC, despite the ready availability of that information for Verizon.

Verizon claimed that it should not be punished for having a cost study that tracks the TELRIC of providing UNEs and making that information available to the Commission for pricing purposes.

COMMISSION DISCUSSION AND CONCLUSIONS

The Commission will address each of the Public Staff's comments separately below, by Company.

BELLSOUTH

ISSUE NO. 1 - The Public Staff's first comment concerns the fact that BellSouth inadvertently placed the Wendell wire center in Zone 3. BellSouth commented that it concurs with the Public Staff's observation and has agreed to modify its filing to place the Wendell wire center in Zone 2.

COMMISSION CONCLUSIONS: The Commission recognizes and approves a change to place the Wendell wire center in Zone 2.

ISSUE NO. 2 - Concerning the Public Staff's second comment on the removal of the amortization of the nonrecurring costs associated with disconnection and then adding it back to the resulting deaveraged rate, the Commission understands the confusion. The Commission notes that the Public Staff is correct that the Commission's March 15, 2001 Recommended Order does show the manner in which the zones were to be determined using BellSouth's 2-wire loop yet makes no distinction between the amortization component and the remainder of the UNE rate. The Commission does not believe that it was the intent of that Order to require BellSouth not to exclude the amortization of the nonrecurring disconnection charges although the Commission can certainly see how that interpretation was made. The Commission believes that it was simply an oversight that the amortization of the nonrecurring charges piece of the calculation was not shown in the example included in the March 15, 2001 Recommended Order. Further, the Commission believes that not allowing BellSouth to exclude the amortization of the nonrecurring disconnection charges would result in a conflict with the Commission's finding that nonrecurring charges should not be deaveraged that this point in time. Therefore, the Commission concludes that BellSouth appropriately removed that portion of the rate reflecting the amortization of the nonrecurring cost associated with disconnection and then added that component to the resulting deaveraged rate.

COMMISSION CONCLUSIONS: The Commission concludes that BellSouth appropriately removed that portion of the rate reflecting the amortization of the nonrecurring cost associated with disconnection and then added that component to the resulting deaveraged rate.

SPRINT

ISSUE NO. 1 - The Public Staff noted that Sprint filed deaveraged rates for subloops although the Commission has not yet established permanent statewide average rates for subloops. Sprint agreed with the Public Staff's observation and noted that it would withdraw those rates, however has not yet done so. The Commission finds it appropriate to recognizes that deaveraged subloop rates should not be considered at this point in time but should be addressed after the Commission orders final permanent statewide subloop rates.

COMMISSION CONCLUSIONS: The Commission recognizes that deaveraged subloop rates should not be considered at this point in time but should be addressed after the Commission orders final permanent statewide subloop rates.

ISSUE NO. 2 - The Public Staff noted that Sprint did not deaverage all of the components of its proposed rates for ISDN-BRI loops greater than 18,000 feet, DS-1 56/64K loops, and DS-1 loops. Sprint responded that the components mentioned by the Public Staff cover the costs of electronics needed to provide each of the services and do not vary with geographic location. The Commission notes that this issue is similar to Issue No. 2 for BellSouth, however, there is a distinguishing difference. BellSouth removed a component consisting of the amortization of nonrecurring charges associated with disconnection. The Commission did conclude in its March 15, 2001 Recommended Order that nonrecurring charges should not be deaveraged at this point in time, and no Party filed an Exception to that finding. However, it appears that Sprint has removed components which it concludes do not vary by geography although the Commission has made no such finding. Therefore, the Commission believes that the Public Staff is correct that Sprint should not remove components (or adders as Sprint refers to them) from its deaveraging calculation. The Commission agrees with the Public Staff that the entire UNE loop rate should be in the deaveraging calculation regardless of the origin of the component costs with the exception of nonrecurring charges which the Commission has concluded should not be deaveraged at this point in time.

COMMISSION CONCLUSIONS: The Commission concludes that Sprint should deaverage all components of its rates for ISDN-BRI loops greater than 18,000 feet, DS-0 56/64K loops, and DS-1 loops, consistent with the Public Staff's recommendation.

VERIZON

ISSUE NO. 1 - The Public Staff noted that the calculation used by Verizon in determining the average loop investment per wire center does not include all of the loop investment. Verizon commented that it has recalculated its total investment per wire center and made the appropriate changes. Therefore, the Commission concludes that when Verizon makes its final filing on deaveraging that it include all of the loop investment in determining the average loop investment per wire center, as recommended by the Public Staff and agreed to by Verizon.

COMMISSION CONCLUSIONS: The Commission concludes that Verizon's final deaveraging proposal should include all of the loop investment in determining the average loop investment per wire center.

ISSUE NO. 2 - The Public Staff noted that Verizon excluded the costs for electronics, testing, and common costs prior to deaveraging its UNE rates and then after completing the deaveraging calculation, added the excluded costs to the resulting rates. Verizon maintained that electronics, testing, and common costs do not vary by geography or volume, and therefore are appropriately excluded. As with Sprint, the Commission notes that Verizon has removed components which it concluded do not vary by geography although the Commission has made no such finding. Therefore, the Commission believes that the Public Staff is correct that Verizon should not remove electronics, testing, and common costs from its deaveraging calculation. The Commission agrees with the Public Staff that the entire UNE loop rate should be in the deaveraging calculation regardless of the origin of the component costs with the exception of nonrecurring charges which the Commission has concluded should not be deaveraged at this point in time.

COMMISSION CONCLUSIONS: The Commission concludes that Verizon should deaverage all components and should not exclude electronics, testing, or common costs from its deaveraging calculation, consistent with the Public Staff's recommendation.

ISSUE NO. 3 - The Public Staff noted that the Commission intended for the Companies to use the same methodology in computing the rates for each zone, and Verizon has not done so. The Public Staff explained that BellSouth and Sprint calculated the ratio of each zone's rate to the statewide average using the average loop investment, thereby applying the same ratio to the statewide average in calculating the zone rates for all of the UNE loop rates. Verizon maintained that although it did not apply the same rate-setting method applied by BellSouth and Sprint, mandating its application to Verizon would punish Verizon for having a cost study that tracks the TELRIC of providing UNEs and making that information available to the Commission for pricing purposes.

The Commission does not believe that requiring consistency in the computation of rates for each zone by all of the ILECs results in punishment of Verizon for having a cost study that tracks the TELRIC of providing UNEs. The Commission agrees with the Public Staff that the method used by BellSouth and Sprint wherein the ratio used was a ratio of each zone's rate to the statewide average using the average loop investment should also be applied to Verizon. Therefore, the Commission concludes that Verizon should calculate rates for each zone by using the ratio of each zone's rate to the statewide average using the average loop investment.

COMMISSION CONCLUSIONS: The Commission concludes that Verizon should calculate rates for each zone by using the ratio of each zone's rate to the statewide average using the average loop investment consistent with the methodology used by BellSouth and Sprint.

GENERAL ISSUES:

(i) COST STUDY FILINGS: The Commission notes that the Public Staff made recommendations on specific instructions for the ILECs on filing their final UNE rates. The Commission agrees with the proposals of the Public Staff. Therefore, the Commission requests the ILECs to file all of their final permanent UNE rates in compliance with the Commission's Orders in both hard copy form and an electronic form compatible with Excel 95/97. Further, the Commission finds it appropriate to instruct the ILECs to include a summary sheet of the resulting rates and a listing of wire centers by both common English name and CLLI code in each zone.

COMMISSION CONCLUSIONS: The Commission requests the ILECs to file all of their final permanent UNE rates in compliance with the Commission's Orders in both hard copy and an electronic form compatible with Excel 95/97. Further, the Commission instructs the ILECs to include a summary sheet of the resulting rates and a listing of wire centers by both common English name and CLLI code in each zone.

(ii) BELLSOUTH'S MOTION FOR EXPEDITED FILINGS: The Commission notes that on October 19, 2001, BellSouth filed a Motion to Allow Expedited Filings of Cost Studies. In its Motion, BellSouth requested that the Commission allow the ILECs to individually file their final deaveraged UNE rates as soon as possible upon entry of the Commission's final order. The Commission finds it appropriate to grant BellSouth's Motion in this regard and to use the language, "file on or before" a date certain to allow BellSouth the flexibility to file its final rates as soon as BellSouth is ready.

COMMISSION CONCLUSIONS: The Commission grants BellSouth's Motion to Allow Expedited Filings of Cost Studies thereby allowing BellSouth the flexibility to file its final rates as soon as BellSouth is ready.

SECTION II - ALLTEL'S MOTION TO DEAVERAGE NONRECURRING CHARGES

BACKGROUND

On October 26, 2001, ALLTEL Communications, Inc. (ALLTEL) filed a Motion for Deaveraging of Nonrecurring Charges Associated with Provisioning of Unbundled Network Elements (UNEs). ALLTEL stated that pursuant to 47 U.S.C. §§ 251 and 261, Orders of the FCC, and the prior Orders of this Commission in this docket, it requests that the Commission initiate proceedings to geographically deaverage the nonrecurring charges previously established by the Commission for BellSouth, Sprint, and Verizon or to otherwise establish those charges in accordance with the FCC's rules.

ALLTEL asserted that by Order dated December 10, 1998, the Commission first established statewide averaged recurring and nonrecurring charges for BellSouth, Sprint, and Verizon. ALLTEL noted that by its Order Adopting Permanent UNE Rates issued on March 13, 2000, the Commission established permanent averaged statewide UNE rates for BellSouth, Sprint, and Verizon. ALLTEL commented that thereafter, the Commission undertook proceedings to geographically deaverage UNE prices and found in its March 15, 2001 Order that nonrecurring charges should not be deaveraged at this time.

ALLTEL maintained that nonrecurring charges are those charges assessed by the ILECs in connection with their provision of services and are, in fact, a very real component of the cost which CLPs must pay to obtain UNEs from the ILECs. ALLTEL noted that CLPs do not recover this cost of obtaining UNEs to establish service from their customers in a lump sum payment at the time service is established.

ALLTEL asserted that nonrecurring charges have been addressed independently, or as part of the deaveraging process, in Alabama, Florida, Georgia, Kentucky, Louisiana, South Carolina, and Tennessee. ALLTEL maintained that the nonrecurring charges that have been proposed or approved by the respective public utility commissions in those BellSouth states are significantly lower than BellSouth's nonrecurring charges in North Carolina. ALLTEL provided the following comparison information of the nonrecurring charges for a 4-wire DS1 loop:

4-wire DS1 loop	North Carolina	Florida	Georgia	Louisiana	Tennessee
First	$714.84	$313.75	$429.98	$245.16	$313.08
Additional	$421.47	$181.48	$268.18	$152.98	$219.72

ALLTEL alleged that the practical consequence to CLPs of BellSouth's extremely high nonrecurring charges in North Carolina is to further impair CLPs' ability to compete. ALLTEL noted that the interim BellSouth nonrecurring charge for a 4-wire DS1 loop was $568.96 and that the permanent nonrecurring rate for that same service is $714.84. ALLTEL stated that while the deaveraging of the monthly recurring rate for the underlying UNE decreased the recurring monthly rate for a 4-wire DS1 loop from $62.78 to $48.27, the dramatically increased nonrecurring charge for the initial establishment of that service effectively negates any saving to the CLP.

ALLTEL concluded that as deaveraging of nonrecurring charges is essential to the establishment of meaningful competition in the State, ALLTEL submits that the Commission should geographically deaverage nonrecurring charges before taking final action on BellSouth's pending Section 271 Application. ALLTEL requested that the Commission initiate proceedings to geographically deaverage nonrecurring charges for the ILECs and direct the ILECs to implement those deaveraged nonrecurring charges, or otherwise establish nonrecurring charges for the ILECs which comply with the requirements of the FCC's rules before the Commission takes any final action on BellSouth's pending Section 271 Application.

On November 5, 2001, the Commission issued an Order requesting comments from interested Parties on ALLTEL's Motion.

COMMENTS ON ALLTEL'S MOTION

AT&T: AT&T stated in its comments that it agrees with ALLTEL that not only the existing nonrecurring rates, but also the recurring rates for BellSouth do not comport with the FCC's

TELRIC pricing rules and those rates must be set in accordance with TELRIC pricing rules before the Commission can take final action of BellSouth's Section 271 Application.

AT&T stated that as it has advocated in this docket, changes to BellSouth's cost studies are necessary to conform those cost studies to nondiscriminatory costing principles. AT&T noted that BellSouth itself has stated it is willing to re-file cost support based on updated models and updated inputs in its Responses to Exceptions filed in this docket on the Commission's June 7, 2001 Recommended Order Concerning All Phase I and Phase II UNE Issues Excluding Geographic Deaveraging. AT&T commented that BellSouth has filed updated cost models in every state in its region except North Carolina and Tennessee. AT&T noted that in Georgia, where there is a pending UNE proceeding, BellSouth has rejected the use of a sampling technique, which is the method that was used to derive the existing rates in North Carolina, and is proposing the use of updated cost models.

AT&T urged the Commission to establish a procedural schedule for a new cost proceeding to develop rates for UNEs that comport with the FCC pricing rules and to further the development of competition and consumer choice in North Carolina.

BELLSOUTH: BellSouth explained in its comments that ALLTEL raises two separate and distinct issues in its Motion. BellSouth asserted that ALLTEL addresses the issue of deaveraging nonrecurring charges and addresses recent proceedings in other BellSouth states that resulted in a significant decrease in BellSouth's nonrecurring charges. BellSouth asserted that these two issues are unrelated.

BellSouth noted that the Commission concluded in its March 15, 2001 Recommended Order that nonrecurring charges should not be deaveraged at this time. BellSouth stated that ALLTEL's request is untimely, at best, given that the Parties to this proceeding were provided several opportunities to file comments on the Commission's decision, and no Party filed an exception to the Commission's conclusion on this issue. BellSouth asserted that ALLTEL certainly had equal opportunity to raise this issue during the normal course of the docket and for whatever reason, ALLTEL did not do so.

BellSouth asserted that contrary to ALLTEL's position, deaveraging of nonrecurring charges would result in little, if any, variation from zone to zone. BellSouth noted that ALLTEL correctly stated that deaveraging of the monthly recurring rate for an unbundled 4-wire DS1 loop resulted in a decrease from the statewide average of $62.78 to a rate of $48.27, however, BellSouth stated, as ALLTEL is surely aware, the deaveraged recurring rate for an unbundled 4-wire DS1 loop in Zone 3 is $131.95. Apparently, BellSouth alleged, ALLTEL is only concerned about obtaining lowered UNE rates in Zone 1. In any event, BellSouth commented, ALLTEL's brief discussion of the impact of deaveraging on recurring rates is irrelevant, because there would be no such impact on nonrecurring charges if they were somehow to be deaveraged.

BellSouth stated that ALLTEL erroneously attempts to portray deaveraging as the reason for the difference in nonrecurring charges in the BellSouth states. BellSouth maintained that rate deaveraging has been addressed by every other state commission in BellSouth's region, and none have found that nonrecurring charges should be deaveraged. Therefore, BellSouth asserted, deaveraging played absolutely no part in the establishment of any nonrecurring charges in any BellSouth state.

BellSouth concluded that ALLTEL has offered nothing to support its erroneous contention that deaveraging of nonrecurring charges is appropriate, nor has it offered any proof that deaveraging of nonrecurring charges would result in significant rate variations. BellSouth recommended that the Commission deny ALLTEL's Motion.

PUBLIC STAFF: The Public Staff stated in its comments that although ALLTEL did not participate in this proceeding on geographic deaveraging that began in 1999, ALLTEL essentially proposes that the Commission now reject the finding in its March 15, 2001 Recommended Order that nonrecurring charges should not be deaveraged at this time.

The Public Staff noted that in the hearings in this docket, none of the Parties contended that nonrecurring charges should be deaveraged – not even Parties such as Sprint and the New Entrants who were enthusiastic in their support for UNE rate deaveraging and proposed to deaverage the recurring charges for a large number of UNEs. The Public Staff pointed out that BellSouth witness Caldwell and Sprint witness McMahon testified that nonrecurring charges are generally based on labor costs which do not vary significantly by geographic location and that no other witness took issue with their testimony.

The Public Staff maintained that ALLTEL does not present any factual information suggesting that conditions have changed and it is now appropriate to deaverage nonrecurring charges.

The Public Staff commented that a reading of ALLTEL's Motion gives the impression that ALLTEL is not so much requesting deaverage rates for nonrecurring charges as it is simply complaining to the Commission about what it considers to be excessively high rates for nonrecurring charges imposed by BellSouth. The Public Staff noted that ALLTEL lists the nonrecurring charges approved for BellSouth by four other state commissions, however, the Public Staff states that none of these rates are deaveraged.

The Public Staff maintained that ALLTEL makes no argument that nonrecurring costs vary by geographic area, and instead, its sole complaint is that the nonrecurring charges permanently fixed by the Commission in its Order of March 13, 2000 – over 20 months ago – are too high. The Public Staff argued that in reality, if the Commission were to proceed as ALLTEL proposes, then only Zone 1 wire centers would see a decrease in the nonrecurring charge and the nonrecurring rates for wire centers in Zones 2 and 3 would be increased.

The Public Staff recommended that the Commission deny ALLTEL's Motion.

SPRINT: Sprint stated in its comments that ALLTEL's Motion is without merit and should be denied. Sprint argued that ALLTEL's Motion makes no credible case whatsoever for deaveraging nonrecurring charges. Sprint stated that the allegation that other states have set lower statewide average nonrecurring charges than North Carolina does not speak to deaveraged nonrecurring charges within a single state at all. Sprint argued that ALLTEL is simply trying to make another attempt to alter the Commission-approved nonrecurring charges.

Sprint concluded that ALLTEL has provided no additional credible evidence for the Commission to reverse its conclusion not to deaverage nonrecurring charges as outlined in its March 15, 2001 Recommended Order. Sprint argued that deaveraging nonrecurring charges would be inconsistent with the purpose of geographic deaveraging, would lessen the economic correlation between costs and price, and would be in conflict with the Commission's definition of geographic deaveraging.

VERIZON: Verizon filed comments in opposition to ALLTEL's Motion. Verizon stated that ALLTEL is moving for the Commission to do the very thing that it determined was inappropriate – to deaverage costs that do not vary by geography within North Carolina. Verizon maintained that ALLTEL has not and cannot offer any rationale for reversing the Commission's decision just seven months after it was rendered. Verizon observed that no facts or laws have changed to suddenly make deaveraging nonrecurring charges appropriate. Verizon asserted that ALLTEL's Motion appears to be nothing more than a request that the Commission revisit the permanent UNE rates and an effort to delay BellSouth's entry into the long distance telecommunications market.

Verizon also noted that ALLTEL had many opportunities to comment on the Commission's Recommended Order on deaveraging and filed no exceptions or comments. Verizon also contended that ALLTEL's Motion is a procedurally inappropriate attempt to challenge the rates themselves. Verizon maintained that granting ALLTEL's Motion would sanction the circumvention of established Commission procedures and squander the resources of the Commission and the Parties, which will be effectively forced to re-litigate Phase I of this docket.

Verizon asserted that ALLTEL asks the Commission to initiate an open-ended proceeding that could conceivably entail a reexamination of the Commission's permanent nonrecurring rates, BellSouth's Section 271 Application, and the Commission's overall approach to geographic deaveraging.

Verizon stated that because ALLTEL does not allege which FCC rules North Carolina's permanent nonrecurring rates may violate, it is improperly asking the Commission for carte blanche to challenge those rates established in the March 13, 2000 Order.

Verizon asserted that the Commission should decline ALLTEL's invitation to elevate a company's particular competitive objectives above sound public policy.

Verizon also stated that ALLTEL's assertion that competition will suffer because BellSouth's nonrecurring rates in North Carolina are higher than in other states is unfounded and that ALLTEL fails to recognize the plain fact that it will be competing only with other companies in North Carolina. Verizon maintained that ALLTEL is not competing in North Carolina with any entity capable of taking BellSouth's lower nonrecurring charges offered in other states.

Verizon concluded that ALLTEL had ample opportunity to address the deaveraging of nonrecurring rates within the context of the deaveraging Order, and chose not to do so. Verizon recommended that the Commission not permit ALLTEL's untimely attack on the permanent nonrecurring rates of not just BellSouth, but all ILECs, or its procedurally improper attempt to derail BellSouth's Section 271 Application. Verizon recommended that the Commission deny ALLTEL's Motion.

WORLDCOM: WorldCom stated in its comments that it wholeheartedly concurs in ALLTEL's assertions that the nonrecurring rates set by the Commission do not comport with the FCC's TELRIC pricing rules and that those rates must be set in accordance with TELRIC pricing rules before the Commission can take final action on BellSouth's Section 271 Application. WorldCom noted that it has repeatedly advanced the argument that the nonrecurring rates set by the Commission do not comport with the FCC's TELRIC pricing rules in its briefs, comments, reply comments, and exceptions filed in this docket. WorldCom stated that it has advanced the argument that nonrecurring rates must be set in accordance with TELRIC pricing rules before the Commission can take final action on BellSouth's Section 271 Application in its testimony filed in BellSouth's Section 271 docket. WorldCom argued that the previously determined rates were derived from sampling conducted five or more years ago of BellSouth's embedded network configuration and design. Therefore, WorldCom alleged, the rates are stale-dated, as well as not reflective of a "scorched node" TELRIC approach.

WorldCom noted that it has advocated in its comments filed in this docket along with testimony in BellSouth's Section 271 docket that the Commission establish a UNE cost proceeding in which BellSouth and other interested parties file cost models that are capable of producing TELRIC. WorldCom noted that BellSouth has filed updated cost models in every state in its region except North Carolina and Tennessee. Significantly, WorldCom asserted, the Georgia Public Service Commission, in whose state MCI has launched local residential service, has a pending UNE cost proceeding in which BellSouth has abandoned use of a sampling technique and is proposing the use of updated cost models. WorldCom argued that a new cost proceeding is also vitally important to the development of competition and consumer choice in North Carolina. WorldCom maintained that only when the Commission has established UNE rates in conformity with the FCC's pricing rules will there be the opportunity for broad-based residential local exchange competition in this State.

COMMISSION DISCUSSION AND CONCLUSIONS

The Commission agrees with BellSouth and the Public Staff that ALLTEL's Motion has two separate requests. First, ALLTEL is outwardly requesting that the Commission deaverage nonrecurring rates. The Commission agrees with BellSouth and Verizon that ALLTEL's Motion is untimely. The Commission notes that the Commission has had an open docket to address deaveraging since 1999 and has made a final decision in that case that nonrecurring charges should not be deaveraged at this point in time. The Commission notes that no Party filed an Exception to that Finding of Fact. The Commission believes that ALLTEL has had ample opportunity to express its opinion on deaveraging nonrecurring charges and has chosen not to do so until after the Commission has issued an Order and considered Motions for Reconsideration on that Order although none were filed on this issue. Further, the Commission agrees with the Public Staff, Sprint, and Verizon that ALLTEL's Motion does not present any new factual information which would impact the Commission's decision not to deaverage nonrecurring charges at this point in time. Therefore, the Commission finds it appropriate to deny ALLTEL's Motion to deaverage nonrecurring charges.

The Commission believes that ALLTEL is making a second request in its Motion, although not clearly and specifically stated, which is a request for the Commission to reexamine BellSouth's statewide average nonrecurring charges. The Commission established permanent statewide average UNE rates in March 2000. As the Public Staff correctly noted, ALLTEL's comparison of

BellSouth's nonrecurring rates for a 4-wire DS1 loop between North Carolina, Florida, Georgia, Louisiana, and Tennessee actually compares statewide average nonrecurring rates and not deaveraged nonrecurring rates. Although the Commission is concerned about ALLTEL's allegations that BellSouth has filed new cost studies in other states which do not utilize a sampling method and that other states have reduced the statewide average nonrecurring charges, the Commission does not believe that ALLTEL's Motion is the appropriate forum for the Commission to make a determination to open up the UNE docket to attempt to establish new nonrecurring (and presumably recurring) rates. The Commission comments that WorldCom noted that it has filed testimony in BellSouth's Section 271 docket advocating that the Commission establish a new UNE cost proceeding. The Commission finds it appropriate to take notice of the information in ALLTEL's Motion including the UNE rates in other BellSouth states but not establish a new UNE cost proceeding in response to ALLTEL's Motion.

COMMISSION CONCLUSIONS: The Commission denies ALLTEL's Motion and concludes that it is not appropriate to reconsider the Commission's decision not to deaverage nonrecurring charges at this point in time nor establish a new UNE cost proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That it is appropriate for BellSouth to place the Wendell wire center in Zone 2.

2. That BellSouth appropriately removed that portion of the rate reflecting the amortization of the nonrecurring cost associated with disconnection and then added that component to the resulting deaveraged rate.

3. That deaveraged subloop rates should not be considered at this point in time but should be addressed after the Commission orders final permanent statewide subloop rates.

4. That Sprint should deaverage all components of its rates for ISDN-BRI loops greater than 18,000 feet, DS-0 56/64K loops, and DS-1 loops, consistent with the Public Staff's recommendation.

5. That Verizon's final deaveraging proposal should include all of the loop investment in determining the average loop investment per wire center.

6. That Verizon should deaverage all components and should not exclude electronics, testing, or common costs from its deaveraging calculation, consistent with the Public Staff's recommendation.

7. That Verizon should calculate rates for each zone by using the ratio of each zone's rate to the statewide average using the average loop investment consistent with the methodology used by BellSouth and Sprint.

8. That BellSouth, Sprint, and Verizon shall file all of their final permanent UNE rates in compliance with the Commission's Orders in both hard copy and an electronic form compatible with Excel 95/97. Further, the Commission instructs the ILECs to include a summary sheet of the resulting rates and a listing of wire centers by both common English name and CLLI code in each zone.

9. That BellSouth's Motion to Allow Expedited Filings of Cost Studies is hereby granted.

10. That BellSouth, Sprint, and Verizon shall refile their cost studies in compliance with this Order on or before Thursday, January 10, 2002.

11. That ALLTEL's Motion to Deaverage Nonrecurring Charges Associated with the Provisioning of UNEs is hereby denied. It is not appropriate to reconsider the Commission's decision not to deaverage nonrecurring charges at this point in time nor establish a new UNE cost proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Commissioner James Y. Kerr, II did not participate in this decision.
bp121001.01

DOCKET NO. P-100, SUB 133m

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Intercarrier Compensation for Internet Service Provider Traffic	))	ORDER ELIMINATING TRUE-UP REQUIREMENT

BY THE COMMISSION: On May 11, 2001, the Commission issued an Order Requesting Comments in response to the Federal Communication Commission's (FCC's) April 27, 2001 Order in CC Docket 9-98 (ISP Traffic Remand Order) in which the FCC established on a prospective basis a transitional intercarrier compensation mechanism for the exchange of such traffic to be effective 30 days after publication in the Federal Register. This Order was a follow up to the FCC's February 26, 1999 Order (Declaratory Ruling) in which the FCC found that ISP-bound traffic was "jurisdictionally mixed and largely interstate, and the reciprocal compensation obligations do not apply to this traffic." Reciprocal compensation continued, however, under the then-existing contracts of carriers, and the FCC issued a Notice of Proposed Rulemaking which led to the April 27, 2001 Order.

In response to the FCC Declaratory Ruling on ISP traffic, the Commission instituted an interim intercarrier compensation mechanism applicable to "new interconnection agreements"--those entered into after the Declaratory Ruling--which would have the same rates as those for local traffic generally but would be subject to true-up at such time as the FCC issued its Order subsequent to the Declaratory Ruling and the Commission dealt with it.

However, in light of the ISP Traffic Remand Order, the Commission expressed concerns as to whether the true-up feature of our interim intercarrier compensation mechanism is practicable and should be continued in force. Accordingly, the Commission sought comments on the following issues:

1. Whether the true-up feature of the interim intercarrier compensation mechanism for ISP-bound traffic adopted by the Commission in recent arbitration proceedings is practicable in light of the FCC's recent Order.

2. If a true-up is practicable, whether a true-up should be applied and, if so, how it should operate.

3. Such other observations about the FCC Order as may be pertinent to this Commission with respect to the issue of intercarrier compensation for ISP traffic.

Comments

AT&T Communications of the Southern States, Inc. and TCG of the Carolinas, Inc. (AT&T) stated that it believed that the FCC's ISP Traffic Remand Order has no retroactive application and that a true up of the interim intercarrier compensation mechanism for ISP-bound traffic is not practical. The least complicated and most straightforward method to address reciprocal compensation for ISP-bound traffic is to treat such traffic the same as all other local traffic for the purposes of reciprocal compensation for the period of time from the expiration of the previous interconnection agreement until the effective date of the FCC Order.

MCImetro Access Transmission Services, LLC and Time Warner Telecom of North Carolina, LP (collectively, MCI) observed that the apparent premise of the Commission's true-up decision was that the FCC would adopt a permanent compensation mechanism that was retrospective. However, this did not happen. It would thus be impractical for the Commission to implement a true-up at this time. For one thing, because the FCC rule is prospective, there is nothing to true-up. Second, the FCC mechanism is to be phased in over time, which would complicate matters considerably. Third, ILECs have not yet made an election regarding whether they will exchange all traffic subject to the reciprocal compensation at the same rate. Fourth, the FCC's transitional cost recovery mechanism for ISP-bound traffic establishes rate caps for interstate information access without reference to geographic coverage of the CLP's network, which is inconsistent with the Commission's decision regarding tandem serving areas. Finally, the FCC Remand Order is subject to appeal, and it would be premature and wasteful to attempt to calculate true-up payments based upon the FCC's new mechanism.

Verizon South, Inc. (Verizon) stated that it had no Commission-mandated true-up mechanism in any of its interconnection contracts and therefore had no specific comments on Issues 1 and 2 but instead made a number of observations on reciprocal compensation and the FCC's handling of the issue. Verizon endorsed the thrust of the FCC decisions in finding such traffic to be long distance and thus under the FCC's purview.

Intermedia Communications, Inc. (Intermedia) believed that a retroactive true-up is not practicable because there is no permanent rate applicable to the time periods in question that can be reconciled with the interim rates. The FCC compensation regime is prospective in nature. As such, the Commission is under no present obligation to take any action with respect to implementing the new FCC-established reciprocal compensation regime. However, the Commission should act to clarify the rates applicable to past periods, making the interim rates permanent until the new FCC rate caps take effect.

Carolina Telephone and Telegraph Company and Central Telephone Company (collectively, Sprint) observed that it is likely that the ISP Traffic Remand Order will be challenged in court and may very well be stayed. Thus, it is questionable whether the Commission should take any definitive action with respect to the FCC Order at this time.

US LEC of North Carolina, Inc. (US LEC) believed that a retroactive true-up is not practicable in light of the ISP Traffic Remand Order due to its prospective nature. However, a prospective true-up may be appropriate but only if BellSouth effectively offers to exchange all traffic at the rate set forth in the Order. Any such prospective true-up should include a mechanism for further adjustment upon action by the D.C. Circuit. Any prospective true-up would be applicable only as to traffic exchanged prior to the effective date of the ISP Traffic Remand Order. In any event, the Commission should direct BellSouth to comply with the reciprocal compensation provisions in existing agreements.

BellSouth Telecommunications, Inc. (BellSouth) contended that a true-up of amounts paid and owed under the interconnection agreements is not only practicable but also equitable. Since the CLPs have been compensated for ISP-bound traffic under the interim intercarrier compensation mechanism as if they were receiving reciprocal compensation for local traffic, to disregard the true-up would result in BellSouth having paid, for all practical purposes, reciprocal compensation for ISP-bound traffic which it did not owe. Two scenarios are possible. In the first, the Commission would apply the FCC's analysis regarding its jurisdiction over such traffic retroactively and would conclude that no compensation would be due for ISP-bound traffic for the period prior to the date the FCC put such rates into place (i.e., June 14, 2001), and all monies paid by BellSouth to CLPs would be refunded. The second scenario would be for the Commission to apply the rates ultimately adopted by the FCC retroactively to the effective date of the interconnection agreements at issue. Thus, the Commission should apply the FCC's rate of $.0015 per minute of use to all ISP-bound traffic minutes of use exchanged from the effective date of the interconnection agreements at issue through June 13, 2001, after which the FCC rates would apply. Parties should be required to identify ISP-bound traffic for the period based on the methodology set out in the ISP Traffic Remand Order.

Reply Comments

ALLTEL Communications, Inc. (ALLTEL) observed that BellSouth would benefit from a retroactive application of reduced rates were the Commission to apply the rates ultimately adopted by the FCC retroactively to the effective date of the interconnection agreements at issue. However, under the FCC Order, application of the reduced rates for ISP traffic will also result in the application of the same reduced rates to other forms of local traffic, including wireless traffic terminated on

BellSouth's network. ALLTEL stated that it is both a CLP and a wireless carrier. It would be inequitable and unlawful for the retroactive rate reduction to be applied only to ISP traffic.

Public Staff, after extensively discussing the legal background of the reciprocal compensation controversy, stated that it does not believe that it is practicable to true-up the interim intercarrier compensation rate for ISP-bound traffic adopted by the Commission in recent arbitration proceedings. The Commission should instead wait and adopt a final rate after the appeal from the ISP Traffic Remand Order and any subsequent proceedings in the FCC's intercarrier compensation docket have been resolved. The Public Staff also observed that the ISP Traffic Remand Order stated that the FCC did not intend to preempt state rulings on compensation prior to the effective date of that Order, which was June 14, 2001. The Public Staff stated that, as of that date, the reciprocal compensation rates set by this Commission should no longer be viewed as having any effect under state law and should not be considered subject to true-up, although the rates set by the Commission remain in effect as a matter of federal law until the ILECs have made an election as to all local traffic.

Verizon maintained that the ISP Traffic Remand Order shows that ISP-bound traffic is not now and never has been subject to a reciprocal compensation obligation. This follows from the FCC's finding that the service of forwarding Internet-bound traffic comes within Section 251(b) and is not governed by Section 251(b)(5). Accordingly, Verizon believes that the Commission should find that no compensation is due for ISP-bound traffic for the period before the FCC instituted its interim rate regime.

MCI reiterated that the ISP Traffic Remand Order was prospective and did not interfere with compensation arrangements for ISP-bound traffic predating the new regime. However, Verizon and BellSouth have suggested that the logic of that Order requires that the Commission "true-up" by requiring all new entrants to refund all monies paid for termination of ISP-bound traffic. As a compromise, BellSouth has argued that the Commission should order "true-ups" based on a rate for ISP-bound traffic of $0.0015 per minute of use. Neither result is compelled by the FCC ISP Traffic Remand Order or is consistent with it. MCI observed that, even aside from the clearly expressed lack of retroactivity in its Order, the FCC's new interpretation of Section 251(g) and the logic of its new compensation regime do not undermine the Commission's interim intercarrier compensation methodology with respect to previously exchanged traffic. The Commission adopted its interim intercarrier compensation mechanism pursuant to its general authority under Section 252 and the FCC's directives in its initial ISP Order. While the FCC has now preempted differing state commission compensation mechanisms, its latest Order does not preempt previously adopted mechanisms with respect to their retroactive application. MCI identified at least five factors which indicate the impracticability of true-ups: (1) Because the new compensation regime is forward looking only, there is no rate to "true-up" to. (2) The new regime is conditional on the LEC's agreement to exchange all traffic at the newly adopted rates. Thus, a true-up would entail a true-up of all traffic exchanged. (3) Because of the new regime's phased-in nature, any true-up would require an arbitrary selection of a rate. (4) The FCC's Order is under appeal. Therefore, any true-up would be subject to further true-up in the event the FCC's Order is reversed. (5) Any true-up would have to take into account this Commission's previous Orders allowing compensation at the tandem rate where an appropriate showing of geographic similarity is made.

BellSouth observed that a stay had been sought of the ISP Traffic Remand Order and had been denied. BellSouth also stated that it was not suggesting that the ISP Traffic Remand Order be applied retroactively but rather that the Commission should apply the same rate that the FCC determined to be a reasonable transition toward the recovery of costs from end-users. BellSouth is simply asking that the \$.0015 rate be applied as the basis for a true-up. The application of a true-up on that basis would not be unduly difficult.

AT&T argued that BellSouth's suggestion that the Commission never had jurisdiction over the matter is without merit. Moreover, BellSouth's proposal that the Commission retroactively apply the rate ultimately adopted by the FCC for the first six months after the effective date of the Order (i.e, \$.0015 per minute of use) is without merit. The FCC emphasized in its latest Order that the rule does not alter existing obligations under interconnection agreements or past state commission decisions.

US LEC reiterated its view that the substantive underpinning of the Commission's enforcement and arbitration decisions is sound and that nothing in the ISP Traffic Remand Order requires the Commission to revisit or reconsider any aspect of the prior decisions, and no retroactive true-up is necessary or practicable.

ALLTEL stated that the issue before the Commission is not whether there should be a true-up but rather how those rates should be trued-up according to the ISP Traffic Remand Order. BellSouth has indicated that it has elected to adopt the rate structure established in the FCC's latest Order. Moreover, BellSouth must retroactively apply the same rate to all local traffic terminating on its network.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The issue in this docket concerns the relatively narrow question of whether the true-up requirement that the Commission promulgated after the FCC's Declaratory Ruling with respect to reciprocal compensation for ISP-bound traffic is practicable in light of the ISP Traffic Remand Order.

After careful consideration, the Commission concludes that good cause exists not to enforce the true-up requirement applicable to ISP-bound traffic which the Commission promulgated in various arbitrations in the wake of the FCC's Declaratory Ruling on the grounds that such true-up would be impracticable in light of the FCC's ISP Traffic Remand Order. The Commission also finds that, in any event, no true-up requirement applies after the effective date of the ISP Traffic Remand Order (June 14, 2001). However, if a final resolution of the ISP Remand Order leads to a retrospective application of rates to the time of the original Declaratory Ruling (a result that the Commission believes to be highly unlikely), then the Commission may consider revisiting the true-up issue.

The Commission's original position, like that of most other states, was that ISP-bound traffic was local in nature and therefore subject to intercarrier compensation. In February of 1999, the FCC issued its Declaratory Ruling in which it stated that ISP-bound traffic was not local but interstate but went to great lengths to assure state commissions that it was not retroactively invalidating the work they had done. The FCC indicated that it was seeking further comments and would be elaborating on its Declaratory Ruling at a later date. After a number of convolutions in the case, it did so.

After the FCC's Declaratory Ruling, the Commission thought it best, on a going-forward basis, to provide that there would be still be reciprocal compensation for ISP-bound traffic at the same rate and according to the same terms as local traffic generally but that it should be subject to a true-up once the FCC issued its subsequent ruling. It was the Commission's implicit assumption that the FCC's anticipated subsequent Order would be retrospective in nature--that is, it would essentially pick up where the previous Order left off.

This turned out not to be the case. Instead, in its ISP Traffic Remand Order, the FCC indicated that its ruling was prospective.[1] That being the case, it appears to the Commission that, as a matter of law, there is no FCC rate applicable to the interim period between the two FCC Orders for the Commission to true-up against. This is one of the major reasons that the Commission sought comments on whether a true-up was even practicable. Having reviewed the comments and reply comments, the Commission is confirmed in its earlier suspicions that a true-up is impracticable and that this requirement should be not be enforced in the arbitrated agreements. MCI in its Reply Comments has done an especially good job of identifying exactly why this is so.

The Commission furthermore concurs with the Public Staff's analysis that, in any event, there could be no true-up applicable to "carried forward" rates after June 14, 2001, because those rates are now based on federal law and are therefore not subject to true-up.

BellSouth and Verizon have advanced the argument that what the ISP Traffic Remand Order really means is that no reciprocal compensation was ever due from the beginning and that they are due refunds for what they have paid as true-up. (BellSouth has proposed as a compromise using the $.0015 per minute of use derived from the rate for the first six months of the ISP Traffic Remand Order.) Some CLPs, on the other hand, have argued that the true-up should apply to all traffic. The Commission is skeptical of both of these lines of argument. BellSouth's and Verizon's arguments ignore the prospective nature of the FCC Orders, while the CLPs ignore the fact that the true-up by its terms was only supposed to apply to ISP traffic.

[1]The FCC also provided for an "opt in" by the ILEC as to its rate caps for ISP-bound traffic with the trade-off that the ILEC must offer to exchange all local traffic at the same rate. If an ILEC does not opt in, then the existing state rates continue to apply. In North Carolina the arbitrations concluded that the ISP rate and the general local rate for reciprocal compensation should be the same.

The reciprocal compensation issue is likely to remain controverted for quite some time. In the meantime, the Commission will take the modest step of at least removing one small level of its complexity by declaring its previous true-up requirement concerning ISP-bound traffic to be impracticable in light of the nature of the FCC rulings.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of August, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb081301.01

DOCKET NO. P-100, SUB 137

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER NAMING
Area Code Relief Plan for North Carolina's	)	POOLING
704/910/919 Numbering Plan Areas (NPA	)	ADMINISTRATOR AND
	)	IMPLEMENTING
	)	THOUSANDS-BLOCK
	)	NUMBER POOLING

BY THE COMMISSION: On October 6, 2000, the Commission issued an Order Seeking Comment on Industry Recommendation for the Implementation of Thousands-Block Number Pooling. In the Order, the Commission concluded that comments and reply comments should be sought from the industry and other interested parties with regard to the implementation of pooling. The Commission's Order stated comments were to be made on specific recommendations for a Number Pooling Administrator (PA), pros and cons on which NPA pooling should be implemented, and recommendations on cost recovery to include projected costs to implement pooling. In an effort to assist the industry in developing comments, particularly with regard to the requirement in Ordering Paragraph No. 2.b.(1), the Commission Order required proposals from bidders who were interested in serving as the PA. In addition, the Commission convened an industry meeting on October 16, 2000, to discuss the pooling administration proposals submitted by NeuStar, Inc. and Telcordia Technologies, Inc.

Initial comments were filed on October 27, 2000, by Verizon Wireless and on October 30, 2000, by Time Warner Telecom of North Carolina, L.P. (TWTC); and the North Carolina Telecommunications Industry Task Force (Task Force). In these initial comments, it appears that only one party made a specific recommendation as to the party to serve as the PA. The initial comments submitted on behalf of the Task Force suggested that the Commission should gather additional information before making such a decision. The Task Force did not, however, describe the additional information which it needed to make a recommendation to the Commission or the steps which the industry needed to take in order to obtain the necessary information.

Due to the industry, in general, not complying with the Order of October 6, 2000, the Commission on November 3, 2000, issued an Order Regarding Compliance With Commission Order Dated October 6, 2000, stating that reply comments due on November 10, 2000, were to include a "specific recommendation" as to the PA as originally set out in Ordering Paragraph No. 2.b.(1). The Commission noted that, in addition to the information provided at the October 16, 2000, meeting, both NeuStar and Telcordia had filed proposals which the Commission understood could be made available to industry representatives following the execution of an appropriate nondisclosure agreement. On November 8, 2000, the Task Force orally requested that the reply comment date be extended until November 17, 2000, which was approved by Order issued by the Commission on November 13, 2000.

Reply comments were filed on November 17, 2000, by Allegiance Telecom of North Carolina, Inc. (Allegiance); Sprint Communications Company L.P., d/b/a Sprint PCS, Carolina Telephone and Telegraph Company, and Central Telephone Company (collectively, Sprint); XO Communications (formerly NEXTLINK Communications of North Carolina); and, the Task Force. A later filing was also received from Carolina West Wireless. In these comments, two parties made a specific recommendation as to the party to serve as the PA. In addition to Allegiance's comments on thousands-block pooling, it commented that number conservation is a long-term issue and that rate center consolidation is a critical component of a comprehensive, long-term conservation plan.

Also on November 17, 2000, the reply comments submitted on behalf of the Task Force stated that additional information was needed to provide the Commission with a neutral comparison of the bidders. The Task Force further stated that an analysis could be completed by mid-December if the following information is provided by each of the bidders: (1) Cost, (2) Identification of Personnel Assigned to North Carolina, (3) Project Plan, (4) Experience and References, (5) Hours of Operation, (6) Security, and (7) Conformance with Thousands-Block NPA Guidelines. The Task Force commented that BellSouth had been able to sign a nondisclosure agreement with Telcordia and had received Telcordia's proposal. Furthermore, the Task Force stated that NeuStar would only provide a redacted copy of its proposal until it could receive assurances from the Commission that any comments filed with the Commission that spoke to NeuStar's proposal would be treated as proprietary and properly protected due to the confidentiality of information contained in the proposal.

Because the Commission held that the industry remained out of compliance with its Order of October 6, 2000, the Commission on December 6, 2000, issued an Order in this docket noting that reply comments were due December 15, 2000, and requiring the industry to "fully comply with all requirements of the Commission Order in this docket dated October 6, 2000, including Ordering Paragraph No. 2.b.(1)." The Commission continued to stress the point that the industry needed to participate in recommending an administrator for the pooling trial, as well as on other aspects of implementing the trial because of the industry's experience in managing the complexities of this type of project.

On December 15, 2000, the Task Force filed a motion with the Commission requesting an extension of time until January 22, 2001, to file reply comments as required by the December 6, 2000 Order.

Extensions were granted until January 15, 2001, and subsequently until January 29, 2001, at the request of the Task Force to provide adequate time in which to file comments.

Comments and reply comments on the selection of the PA, NPA implementation and cost recovery issues are summarized as follows:

SELECTION OF POOLING ADMINISTRATOR

Time Warner Telecom of North Carolina, L.P. On October 30, 2000, TWTC in its comments recommended NeuStar as the PA. TWTC pointed out that NeuStar was engaged as the PA in California, Colorado, Connecticut, Florida, Illinois, Maine, Nebraska, New Hampshire, New York, Texas and Utah. TWTC commented that Telcordia had been delegated authority as the PA only in Tennessee and, thus, lacks the experience of NeuStar. TWTC stated that they had experience with NeuStar as the PA in California, Florida, and New York and believed that NeuStar's performance in North Carolina would be consistent with its execution in other states. TWTC further stated that consistency is an important consideration for industry members conducting business in multiple states, as congruity among states decreases the cost to those affected industry members.

ITC^Deltacom Communications, Inc. On November 13, 2000, ITC^Deltacom Communications, Inc., filed a letter supporting TWTC's comments and adopting the recommendation of NeuStar as the PA.

XO Communications. On November 17, 2000, XO Communications filed a letter supporting the comments of TWTC and recommended NeuStar as the PA.

North Carolina RSA3 Cellular Telephone Company. On November 28, 2000, North Carolina RSA3 Cellular Telephone Company, d/b/a Carolina West Wireless recommended NeuStar as the PA.

Sprint Communications Company L.P., Sprint Spectrum L.P. d/b/a Sprint PCS, Carolina Telephone and Telegraph Company and Central Telephone Company. On January 29, 2001, Sprint commented that after reviewing the proposals by NeuStar and Telcordia filed with the Commission, found both proposals workable and that either company would be an acceptable choice. "However, Sprint believes NeuStar has presented the better overall proposal for North Carolina based on the following: NeuStar has considerably more experience as a PA in other states; and NeuStar's pricing structure and its ability to merge into the national number pooling administration."

BellSouth Telecommunications, Inc. On January 29, 2001, BellSouth submitted its comments for the PA recommending Telcordia. BellSouth stated that although NeuStar has an edge in its exposure to number pooling administration, BellSouth does not view this as a negative against Telcordia. BellSouth believes that Telcordia has demonstrated that it can handle the level of responsibility as a PA from the industry experiences summarized in its proposal. BellSouth stated that its recommendation was based primarily on two factors, cost and the pooling administration system that the service providers will access via the Internet.

BellSouth commented that Telcordia's costs are clearly and concisely laid out in its proposal, allowing for budgeting and proper cost recovery. BellSouth stated that NeuStar's costs are vague, leaving too much uncertainty as currently stated.

Furthermore, BellSouth commented that Telcordia's pooling administration system accessed by service providers through the Internet, has an edge over NeuStar's application. Telcordia's online reporting includes reports on forecasts, applications and assignments with daily updates. Telcordia's system affords the capability of the service provider to track its applications through Telcordia's system by using a tracking number assigned to each application. According to BellSouth, NeuStar's tracking system which provides numbering resources in each pool, forecasted needs of carriers in the pool for the next calendar quarters and projected central office code resources from NANPA, is updated weekly.

BellSouth stated that it would support the selection of either Telcordia or NeuStar. However since the Commission requested a specific recommendation for the PA, "BellSouth gives a slight edge" to Telcordia.

North Carolina Telecommunications Industry Task Force. On January 29, 2001, the Task Force, filed comments of **neutrality** on the selection of a PA. The Task Force commented that both of the companies involved in the bid, Telcordia and NeuStar, are capable of performing the responsibilities required of administering number pooling. The Task Force stated that based on its members' knowledge of proposals presented in other states, Telcordia's pricing is considered reasonable. Telcordia's pricing schedule shows what will be paid for services with the variable being the number of assignments per month. NeuStar did not quote its prices, deferring final prices until the national contract is awarded. NeuStar discussed options for payment if it was or was not selected as the national PA, without addressing specific costs of providing number pooling administration.

The Task Force acknowledged that NeuStar has pooling experience in several states and did not know of any significant problems having occurred with regard to pooling activities. There is not sufficient data from pooling trials to evaluate Telcordia's performance as a PA.

Also, the Task Force stated that Telcordia's proposed system is the only solution that provides online validation, checking for the accuracy of data being submitted to the system. In addition to Telcordia's system functionality, the Task Force stated that Telcordia would provide a dedicated web site for the North Carolina trial. As stated by the Task Force, NeuStar's proposal does not discuss, except in broad terms, how its web-based interface will work and how customer-specific data will be protected.

NPA IMPLEMENTATION

Verizon Wireless. Verizon Wireless commented that it supported the Commission's effort to implement pooling, noting that non-LNP capable carriers (including wireless carriers) will not be able to participate in pooling until after they become LNP capable sometime in late 2002. In supporting the decision to implement pooling, Verizon Wireless stated that "the Commission must ensure that there is a ready source of numbers to serve the needs of wireless carriers and their customers." Verizon recommended that the first pooling trial should be in the 980 NPA.

Verizon reasoned that the 704/980 NPAs, based on the area code relief plan for 704, is not expected to exhaust until 2008. Given pooling in 704, the Commission may very well extend the life of 704/980 numbering resources beyond 2008.

The second choice recommended was to begin with the 336 NPA. Verizon stated that pooling should begin in this NPA before it goes into an exhaust state, realizing that the current numbering resource projection indicate that area code relief will be necessary by the fourth quarter of 2002.

Verizon commented that pooling should not be undertaken for the 919 NPA because there is less than one year of life left in the NPA. Furthermore, with an implementation date no earlier than the second quarter of 2001, "there will not be enough life left in 919 to ensure access to necessary numbers by wireless carriers."

North Carolina Telecommunications Industry Task Force. In its comments filed on October 30, 2000, "the Task Force recommends that the Commission select the 336 NPA as the first choice to implement thousands-block pooling, the 704/980 NPA as second choice, and the 919 NPA as the third choice." To get maximum benefit from pooling in 336, the Task Force stated that the Commission would need delegated authority from the FCC by January 2001 for implementation by August 1, 2001. This schedule should also allow time for the general availability of the release of 3.0 software.

The Task Force further commented that should the FCC deny delegated authority for 336, or fail to respond before January 2001, it was recommended that the Commission implement pooling in the 980 NPA first. The 704/980 NPAs, based on the current area code relief plan, will allow the greatest number block of uncontaminated thousands-blocks of any NPA in North Carolina, thus maximizing the benefit of number pooling.

Lastly, the Task Force commented that it "discourages any decision to implement thousands-block number pooling in the 919 NPA since it will have little or no impact on the exhaust date and the need for relief in that area code." Currently the 919 NPA is operating under jeopardy procedures to ensure that the numbering resources do not exhaust prior to the fourth quarter of 2001.

Sprint Communications Company L.P., Sprint Spectrum L.P. d/b/a Sprint PCS, Carolina Telephone and Telegraph Company, and Central Telephone Company. On November 17, 2001, Sprint filed comments stating, "like Verizon Wireless, Sprint PCS will be unable to participate in thousands-block pooling." Since Sprint PCS is not LNP capable, they will require numbering resources in 10,000 numbering blocks. Sprint commented that "a relief plan that gives wireless carriers access to numbers in an exhausting area code while leaving wireless carriers without numbers is not acceptable." Although not making a specific recommendation for NPA implementation, Sprint stated that it supported the position of the Task Force and Verizon wireless asking that the 919 NPA "not be considered" for pooling.

Allegiance Telecom of North Carolina, Inc. Allegiance commented that the Commission needed to strongly consider implementing rate center consolidation (RCC), as a conservation measure. Allegiance stated that "the root causes of number exhaust are the allocation of numbers in blocks of 10,000 and the need to obtain distinct NXXs to serve individual rate centers." Carriers must obtain an NXX code for every rate center in which it wants to provide service.

Allegiance stated that the Task Force "... mentions, almost in passing, referring to the 980 NPA that the 980 should be first in implementation due to having the largest number of uncontaminated thousands-blocks" in North Carolina. Allegiance opposes donation of any contaminated thousands-blocks in a number pooling trial because of the administrative and competitive issues which remain unresolved. The competitive issues surrounding informational relationships between the donors and recipients of contaminated thousands blocks have not been completely addressed in the Industry Numbering Committee Pooling Guidelines.

Furthermore, Allegiance commented that it was concerned the Task Force proposal was to begin pooling in the 336 NPA, which would have more contaminated blocks than would be the case beginning in the 980 NPA. Allegiance believes that this market condition would adversely impact new market entrants impairing wireless competition. Lastly, Allegiance "respectfully suggests that the Commission seriously consider implementing RCC to complement the TNP plan;" and that, "to commence number pooling trials in the NPA with the least number of contaminated blocks."

COST RECOVERY

Verizon Wireless. On October 27, 2000, Verizon Wireless filed comments stating "that the Commission follow the recovery method outlined by the FCC, which reflects the method used to allocate LNP costs." Furthermore, Verizon Wireless believes that a single federal recovery mechanism is necessary to ensure consistent cost allocation rules; and also, imposing a state specific cost recovery mechanism on a multi-state provider, such as Verizon Wireless, would be extremely costly and burdensome.

Time Warner Telecom of North Carolina, L.P. TWTC, in its comments filed on October 30, 2000, stated that thousands-block pooling should not be delayed because of cost or software upgrade considerations. TWTC stated that these issues were insignificant compared to the cost of losing some four months or more of number pooling. On the issue of cost recovery, TWTC commented that its experience with NeuStar in California, Florida, and New York is instructive. In those pooling trials, NeuStar and the LLC have entered into agreements with the industry members authorizing NeuStar, the PA, to bill TWTC (and the other industry members) individually and on a consistent monthly basis, allowing the PA to recover the costs of pooling administration.

North Carolina Telecommunications Industry Task Force. The Task Force commented in its filing of October 30, 2000, that it was not prepared to comment on interim cost recovery or projected costs and recommended that the Commission call an Industry Cost Recovery Workshop to address these issues. The Task Force believes that the workshop would present a good platform for the industry to address number pooling cost allocation for the PA and other costs to be included in the recovery. However, the Task Force did say that the cost to implement thousands-block number pooling would be less if implemented using the release 3.0 as opposed to the earlier software version, if for no other reason than avoiding future conversion expenses.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After carefully reviewing all of the comments filed in this docket, the Commission believes that Telcordia should be selected as the PA. Telcordia has presented a focused proposal with specific system support to be used in providing administrative services to the industry in North Carolina. Telcordia has documented that it has a qualified staff, with the necessary level of resources to manage the pooling trial for North Carolina. Although the decision to select Telcordia over NeuStar was difficult, the Commission believes that Telcordia submitted the better overall proposal.

Furthermore, based on the industry comments filed with the Commission, the most reasonable and prudent decision is to begin with a trial thousands-block pooling in the 704 NPA. This course of action addresses implementing a trial in the 704 NPA, which by the delegated authority granted for the 704 NPA also permits pooling in the 980 NPA. The 980 NPA has the largest number of uncontaminated thousands blocks and by utilizing thousands-block pooling, the current exhaust date for the 980 NPA may be extended beyond 2008.

The FCC also granted delegated authority for thousands-block pooling in the 919 NPA. The 919 NPA was not selected for pooling at this time because the existing service life for the 919 NPA potentially has less than twelve months of numbering resources remaining for future assignments. Also, the Commission is currently evaluating area code relief alternatives for the 919 NPA. As relief planning is undertaken for the 919 NPA, the Commission will continue to assess a reasonable timetable for thousands-block pooling for this numbering plan area.

Lastly, the Commission, while interested in addressing the cost recovery aspects of implementing thousands-block pooling on the industry, as well as on the using and consuming public of telecommunication services, believes that FCC direction is needed before implementing final cost recovery at the state level. However, should FCC directives not be provided as envisioned during 2001, the Commission will act to have cost recovery issues addressed by the industry through workshops and industry meetings. In this interim, Telcordia should enter into a contract with the industry for cost recovery.

IT IS, THEREFORE, ORDERED as follows:

1. That Telcordia is appointed and shall serve as the Pooling Administrator for the trial implementation of thousands-block pooling, and shall schedule the initial industry implementation meeting not later than Thursday, March 15, 2001.

2. That Telcordia shall establish, coordinate and implement thousands-block pooling guidelines in the 704 NPA not later than September 15, 2001.

3. That Telcordia shall, in the interim, enter into a contract with the industry for cost recovery until such time as the FCC announces the national pooling program guidelines and practices.

ISSUED BY ORDER OF THE COMMISSION.
This 19th day of February 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

dh021601.01

DOCKET NO. P-100, SUB 137a

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Area Code Relief for North Carolina's 704 Number Plan Area	) ORDER RULING ON) PETITION OF THE NORTH) CAROLINA ALARM) SYSTEMS LICENSING) BOARD

BY THE COMMISSION: On December 22, 2000, the North Carolina Alarm Systems Licensing Board (Board) filed a Petition with the Commission requesting that the 704 Number Plan Area (NPA) area code relief project scheduled for implementation on January 10, 2001, be deferred for six months. By Order dated December 28, 2000, the Commission requested comments from interested parties, by January 4, 2001, on whether the planned overlay relief project could be deferred without causing numbering resource jeopardy.

Comments were filed by the following parties: ALLTEL Carolina, Inc., and ALLTEL Communications, Inc. (ALLTEL); BellSouth Telecommunications Corporation (BellSouth); Sprint Communication Company L.P., and Sprint Spectrum L.P. d/b/a Sprint PCS (Sprint); Time Warner Telecom of North Carolina, L.P. (TWTNC); NeuStar, Inc., as the North American Numbering Plan Administrator (NANPA); and the Public Staff. Comments were also received from the Petitioner, the North Carolina Alarm Systems Licensing Board.

ALLTEL. ALLTEL stated that a delay in implementing the 704 NPA overlay project would result in unwarranted expenses in their operations for engineering translation changes and public relations expenses. ALLTEL has been denied numbering resources from NANPA in the 704 NPA, and therefore is opposed to delaying the relief project. Additionally, ALLTEL has requested two (2) new NXXs to be activated by February 9, 2001, for its operations in the Mooresville and Indian Trail exchanges. ALLTEL urges the Commission to deny the petition to defer the 704 overlay relief project.

BellSouth. BellSouth commented that its effort on consumer education included notices and correspondence on the 704 NPA relief project and the mandatory ten-digit dialing which would be required after the overlay implementation. BellSouth stated that as early as March 6, 2000, it sent letters to the Central Station Alarm Association Administration, Security Industry Association Administration, and the National Burglar and Fire Alarm Association trade groups informing them of the planned overlay project for the 704 NPA and the resulting ten-digit dialing pattern required after implementation of the overlay. BellSouth, in addition to contacting other associations, also on April 17, 2000, contacted the North Carolina Burglar and Fire Association providing notice and outlining the 704 relief project. There was also subsequent mailings of notices and brochures distributed through June 15, 2000.

BellSouth stated that there are currently no NXX codes available in the Charlotte, Statesville and Gastonia rate centers. There are also 48 rate centers with less than three NXX codes available for assignment. Furthermore, codes have already been assigned from the protective group of 704 NPA NXXs, which are to be available with ten-digit dialing at the implementation of the 704 overlay. These code assignments would have to be canceled.

The Board, in its Petition, requested a delay of six months to allow additional time to reprogram its equipment for ten-digit dialing. BellSouth commented that an alternative would be to allow permissive dialing for specific alarm telephone numbers for a period not longer than two months. In order to implement this alternative, there would be certain information that the industry would require from the alarm industry by January 16, 2001, in order to make operational changes by January 24, 2001, to allow permissive dialing for these numbers for an additional two months. No additional changes could be made after January 24, 2001, to extend permissive dialing to other telephone numbers. The success of this alternative would also depend upon the ability of other service providers to make the necessary changes in their respective operating systems.

BellSouth is opposed to the six-month petition to extend the permissive dialing period. Numbering resources are critically short throughout the rate centers in the 704 NPA.

TWTNC. TWTNC, while noting its readiness to implement mandatory ten-digit dialing on January 10, 2001, and the resulting confusion among customers if that date is changed, stated that it does not object to the Board's request.

Sprint. Sprint stated that it will exhaust its numbering resources assigned in the 704 NPA in approximately three to four months. Sprint commented that the alarm industry has had sufficient time and notice to implement ten-digit dialing, and accordingly, Sprint recommended that the Commission maintain the current implementation date of January 10, 2001.

NeuStar. NeuStar, as a neutral party, summarized the availability of numbering resources in the 704 NPA and the assignments already made in the new 980 NPA. NeuStar confirmed that protective codes in 704 NPA have already been assigned based on ten-digit dialing on January 10, 2001. Also, assignments of 49 NXXs have been made in the new 980 NPA to be effective as February 10, 2001. Further, NeuStar confirmed the increasing shortage of assignable NXXs in the existing 704 NPA.

Board. The Board, representing the alarm industry, stated in its comments that it is unable to determine which alarm companies received notification from BellSouth. The Board acknowledged that it had received notices as early as May 2000, of the relief project planned for the 704 NPA and the resulting requirement for ten-digit dialing at the time of implementation of the new NPA. The Board stated that it was not until its November 2000, association meeting that its members expressed grave concern on meeting the ten-digit dialing requirements in its systems by January 10, 2001. After the November meeting, the Board, realizing the magnitude of the alarm companies' problem, petitioned the Commission on December 22, 2000, to request a delay in the overlay relief project for the 704 NPA.

Public Staff. The Public Staff noted that the Board has requested an extension of approximately six months beyond the January 10, 2001 implementation date for the mandatory ten-digit dialing format for the 704 NPA so that all alarm systems can be reprogrammed. Without commenting on the industry's failure to prepare for ten-digit dialing despite having had notice for the better part of a year at least, the Public Staff stated that it recognized the potential adverse effects on alarm system clients if their systems have not been reprogrammed as needed and that the Board's request, therefore, deserves serious attention.

The Public Staff stated that there are significant problems in extending permissive dialing beyond the current January 9, 2001 termination date. As long as seven-digit dialing is enabled, very few codes, if any, in the 980 NPA can be utilized. Forty-nine of the 980 codes have already been assigned to various incumbent local exchange companies (ILECs), competing local providers (CLPs), and wireless carriers and are to be available on February 10, 2001, or shortly thereafter. Twenty-eight of the forty-nine already appear in the Local Exchange Routing Guide (LERG), the industry tool for routing instructions. Generally, codes must appear in the LERG for 45 days before they can be utilized. In addition to the 980 codes which have been assigned, 21 codes in the 704 NPA have been assigned and are scheduled to be available after ten-digit dialing becomes permanent. Few, if any, of these 21 codes can be utilized as long as seven-digit dialing is maintained. The Public Staff further stated that as long as permissive dialing is maintained, very few, if any, new codes can be assigned. This is important not only to existing carriers that are already providing service but also to new carriers. The inability of carriers to implement new codes may prevent them from meeting commitments made to new customers with the understandable expectation of utilizing those codes as planned.

In order to formulate a recommendation on whether or not an extension can be accommodated, the Public Staff stated that it needs information that is not currently available to it. While NANPA has information specifying the carriers to which 980 codes and protected 704 codes have been assigned, the Public Staff stated that its information on these carriers was incomplete. As a result, the Public Staff stated that it was unable to contact the carriers to determine the urgency of their need for the codes. However, the Public Staff stated that it understood, for example, that Sprint Communications, LP, which has been assigned eighteen of the twenty-eight 980 codes that have already been posted in the LERG, has a business need for access to the numbers no later than March 15. If its needs are to be met, permissive dialing must end no later than February 28, 2001, assuming a compressed testing schedule.

The Public Staff stated that BellSouth has agreed to compress its testing, which is scheduled for the period of January 10, 2001 through February 9, 2001, to enable the permissive dialing to be extended for ten business days. This will require overtime to accomplish. The Public Staff asserted a belief that it is reasonable to expect that other ILECs and CLPs can also accommodate such an extension and still be prepared to accommodate introduction of the new 704 and 980 codes on February 9 or 10, 2001, if necessary. According to the Public Staff, the additional ten business days would enable the Commission to gather more information on the problems associated with extending the permissive dialing and delaying the availability of the codes that have already been assigned.

The Public Staff also stated that it had also explored with BellSouth a temporary "solution" which would enable BellSouth offices that serve alarm system customers to be arranged so that the alarm companies' terminating numbers (the seven-digit numbers that the alarm dialers dial when the alarm is triggered) can continue to be dialed on a seven-digit basis after the permissive period is terminated. Like the delay in code availability, however, this solution is fraught with problems. It will require that each of the alarm companies needing relief file a list of its terminating numbers and a list of the NXXs (the first three digits of the seven-digit telephone numbers) of the lines that its customers' alarm dialers use to contact the terminating number. The NXXs will identify the underlying carrier and the serving office of the customers' lines. With this information, BellSouth can, within three to four days, arrange those offices to allow the terminating number to be reached after the permissive period ends. Early indications are that virtually every office in the 704 NPA and a few in the 828 and 803 NPAs will need to be addressed.

Furthermore, the Public Staff stated that the mandatory ten-digit dialing area is not confined to the 704 NPA, but extends southward into the 803 NPA in South Carolina and into the 828 NPA. This introduces a problem with identification of the alarm companies that may be impacted by ten-digit dialing. Those companies that filed comments in support of the Petition can be easily identified, and the Board has information on companies that it licenses. But the Board only licenses companies with monitoring stations in North Carolina. Thus, there can be no assurance that all of the alarm companies needing relief will actually receive it.

Based on its comments, the Public Staff made specific recommendations to the Commission, all of which are addressed by this Order.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the public interest and safety require that permissive dialing in the 704 area code should be extended until January 24, 2001, and that comments should be sought as to what, if any, further relief is feasible and/or desirable.

The Commission makes this decision primarily out of concern for the lives and property of those who have subscribed to the services of alarm companies. The Alarm Systems Licensing Board has represented that an indeterminate number of alarm systems in the 704 area code have not been reprogrammed or replaced on a timely basis. The unfortunate situation we face currently is that since these systems utilize a seven-digit dialing sequence, the implementation of ten-digit dialing will render the alarm signal of noncomplying alarm systems inoperable. There is at this point no way to determine which alarm systems are compliant and which are not. The Commission places responsibility for the situation which we find ourselves in squarely on the alarm industry, more particularly those portions of it that have not reprogrammed or replaced their systems to comply with mandatory ten-digit dialing. The Alarm Systems Licensing Board admits that it had notice of the mandatory implementation at least since May 2000. BellSouth also made special efforts to contact the alarm industry community and requested an alarm company mailing list from the Board in April 2000.[1] The advent of mandatory ten-digit dialing is not like a natural disaster. It is totally predictable and it is well publicized. The alarm industry--even the smaller, less highly capitalized companies-- should have been working diligently on its solution from the start or, at the very least, have presented its concerns to the Commission substantially prior to December 22, 2000, when the Alarm Systems Licensing Board filed its Petition for an extension of permissive dialing.

That said, the Commission recognizes that the problem remains that a certain number of persons who are subscribers to alarm companies which have not updated their systems on a timely basis are at risk. Therefore, it is incumbent upon the Commission and the telecommunications industry to take such measures as are feasible to mitigate this risk, albeit at considerable cost, disruption to those in need of numbers, and confusion.

If certain of the alarm companies bear primary responsibility in the creation of this problem, all must bear a significant responsibility for its solution. Therefore, we stress to the alarm companies the critical need to press forward with the conversion of their dialers, as well as the distinct possibility that we may not be able to provide relief beyond the January 24, 2001 deadline. Further, we cannot be absolutely sure that any technical measures which may be undertaken by the ILECs, CLPs, and telephone membership corporations (TMCs) to extend seven-digit dialing to the terminating alarm numbers will be successful. Accordingly, any reliance that the alarm companies place upon that effort is strictly optional and is at their own risk.

Moreover, it is absolutely imperative that the Alarm Systems Licensing Board, as the only repository of a comprehensive list of licensees, with or without the assistance of any related trade associations, <u>immediately</u> notify alarm companies in or serving the 704 area code that those companies that need relief beyond the extended January 24, 2001, deadline must submit the information requested below by the Commission in ordering paragraph number 4 <u>by no later than January 10, 2001</u>. <u>This deadline is immutable</u>.

IT IS, THEREFORE, ORDERED as follows:

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[1]The process was visible to the public at a considerably earlier date. An Order Requesting Comments and Scheduling Public Hearing, with associated public notices, was issued on February 15, 1999. That Order required each ILEC to provide a bill insert to each subscriber in the 704 NPA prior to April 7, 1999, and required newspaper advertisements for two consecutive weeks prior to March 15, 1999. An Order Approving Overlay Option, together with a press release, was issued on September 15, 1999. The Commission has already once extended the date for mandatory dialing from November 1, 2000, to January 10, 2001.

(1) That the permissive dialing period be extended until January 24, 2001, so that additional information can be obtained on what, if any, further relief is feasible.

(2) That the parties to this proceeding shall file further comments not later than January 12, 2001, addressing the problems and potential remedies associated with an additional 60-day extension until Sunday, March 25, 2001, of permissive dialing and the introduction of the "protected 704 codes" and the 980 codes.

(3) That BellSouth (with the expected full cooperation of NANPA) shall obtain the names, addresses, and telephone numbers of the carriers to which these 980 codes and protected 704 codes have been assigned and the expected in-service dates of the codes already assigned, identify the 980 codes assigned that would duplicate the existing 704 codes in a given basic local and expanded local calling area, and forward this information to the Commission and the Public Staff immediately; monitor and keep the Commission advised of the assignment of additional codes until permissive dialing ends; if at all possible, assign no new 980 codes that would duplicate existing 704 codes in the basic local and expanded local calling areas; and explore the possibility of substituting 980 codes that are compatible with seven-digit dialing for those codes which have already been assigned and which duplicate existing 704 codes in the same basic and expanded local calling areas.

(4) That each and every alarm company which needs relief beyond the extended permissive dialing deadline of January 24, 2001, shall file the following information with the Chief Clerk of the Commission by January 10, 2001, by FAX at (919) 733-7300:

(a) its name, address, contact individual, and telephone and FAX numbers;

(b) certification that it anticipates the need for emergency relief from mandatory ten-digit dialing beyond the January 24, 2001 deadline;

(c) a certified list of the ten-digit numbers (other than 800 or like numbers that are preceded by a 1 when dialed) which its clients' dialers dial on a seven-digit basis in the case of an emergency (all of the non-800 terminating numbers at the monitoring station to which emergency calls are sent); and

(d) a list of the NXXs (first three digits of the seven-digit telephone number) of its clients' lines to which the alarm dialers are attached.

(5) That each ILEC, CLP, and TMC in the affected area shall acknowledge not later than January 10, 2001, by a letter to the Commission (a) that it will extend the mandatory 10-digit dialing conversion from January 10 until January 24, 2001; and (b) that it is willing and able to participate in the emergency measure described by BellSouth and the Public Staff by extending the ability of lines served by identified offices to reach the emergency terminating numbers of the alarm companies' monitoring stations on a seven-digit basis.

(6) That the North Carolina Alarm Systems Licensing Board is ordered to provide assistance to the Commission in immediately getting notice of the provisions of this Order to the alarm companies that need relief.

(7) That all alarm companies affected by the provisions of this Order are hereby notified of the critical need to press forward with their conversion of their dialers and the possibility that there may be no further relief beyond the extended permissive dialing deadline of January 24, 2001.

(8) That the South Carolina Public Utilities Commission, the North Carolina Rural Electrification Authority, and the TMCs in the affected area are hereby requested to concur in and cooperate in the actions which the Commission determines to be appropriate regarding this docket, including the provisions of this Order.

(9) That the Chief Clerk shall mail a copy of this Order to the parties to this proceeding, including the North Carolina Alarm Systems Licensing Board, the South Carolina Public Utilities Commission, the North Carolina Rural Electrification Authority, all ILECs, CLPs, and TMCs.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of January, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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DOCKET NO. P-100, SUB 137b

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	ORDER APPROVING
Area Code Relief for North Carolina's	)	OVERLAY OPTION TO PROVIDE
919 Numbering Plan Area (NPA)	)	AREA CODE RELIEF

BY THE COMMISSION: By this Order, the Commission will address the matter of area code relief for North Carolina area code 919. For all of the reasons set forth below, the Commission concludes that a distributed overlay should be adopted to relieve area code 919 as has been previously implemented in area code 704. The schedule for full implementation of the overlay in the 919 area code is yet to be determined by the Commission. Although the relief mechanism selected for the 919 numbering plan area (NPA) is the overlay, the Commission stresses that its goal and intent is to prolong the service life of the 919 NPA by extensive conservation measures (specifically thousands-block number pooling), and thereby postpone for as long as possible the use of the new overlay area code as well as mandatory 10-digit local dialing.

While there are certainly disadvantages and inconveniences associated with both a geographic split and an overlay, the Commission concludes that the distributed overlay relief method will be least inconvenient and burdensome for consumers, while providing the most significant and long-lasting relief to the area code. That decided, the Commission wishes to strongly emphasize the fact that it will continue to: (1) vigorously pursue the benefits of its number reclamation activities in the NPA;

(2) carefully review assignment and utilization data from the North American Numbering Plan Administrator (NANPA) in the 919 NPA to ensure that conservation measures are being observed; and (3) pursue thousands-block number pooling to achieve all possible numbering resource management benefits applicable to the 919 NPA. The Commission will continue to stress the conservation of numbering resources as a major requirement due to the current demand for numbering resources occurring nationwide, as well as what is being experienced within the State of North Carolina. The Federal Communications Commission (FCC) has provided the Commission with delegated authority for thousands-block number pooling in the 919 NPA and, therefore, it is the Commission's intent to implement thousands-block pooling in the 919 NPA as soon as practical in order to extend the life of that NPA to the maximum extent possible. The Commission will issue an Order in the near future addressing the implementation of thousands-block pooling in the 919 NPA. All industry participants are directed to cooperate in and actively promote this endeavor.

BACKGROUND

An area code is a necessary part of routing calls to their proper destination. When an area code is combined with the second three digits of the telephone number (called the NXX code or Central Office code), a "geographic address" is formed that is used to route calls through the public switched telephone network. The first six digits "tell" the call generally where to go, and the final four digits identify the specific individual customer. For example, the main telephone number of the North Carolina Utilities Commission is 919-733-4249. The area code is 919, 733 is the NXX code or Central Office code, and 4249 is the line number identifying the specific customer receiving the call. North Carolina currently has six area codes assigned to specific geographic areas of the state with a pending overlay in the 704 geographic area scheduled to become effective on March 15, 2001.

Area code exhaust occurs when nearly all of the NXX codes in a given area code have been assigned to telecommunications service providers, even if individual line numbers within the NXX codes have not been assigned to customers. Typically there are 792 NXX codes available for assignment to telephone companies in an area code. Each NXX code has approximately 10,000 line numbers available for assignment to individual customers. Service providers must have the NXX codes assigned to them because the combination of the area code and the NXX code is used to route calls through the public switched telephone network in the North American Numbering Plan (NANP). Some companies also use the NXX code for billing purposes. NXX codes are associated with particular geographic areas, or "rate centers," in an area code. Telephone companies base charges for calls on the distance between the rate center where a call originates and the rate center where the call terminates. These companies must obtain an NXX code in each of the identified geographic areas or "rate centers" in a particular area where they wish to provide service. In the past, local telephone service in any given area was provided by one monopoly carrier, such as BellSouth, Carolina Telephone & Telegraph Company, or Verizon, and the requirement that the telephone company obtain an NXX code for each rate center in an area where it provided service did not strain the supply of NXX codes. Now, however, with the advent of competition in the local telephone service market, there can be several telephone companies providing service in a given area, and each one must obtain an NXX code for each rate center in that area. This change has caused a shortage in the supply of NXX codes.

When almost all of the NXX codes in an area code are assigned to telephone companies, a new area code must be implemented. New area codes usually are implemented in one of two ways. First, they can be implemented through a geographic split, in which the geographic area using an existing area code is split into two parts, and roughly half of the telephone customers continue to be served through the existing area code and half must change to a new area code. Second, new area codes can be implemented through an all services distributed area code overlay, in which the new area code covers the same geographic area as an existing area code, but new customers in that area will be assigned to the new, or overlayed, area code. The FCC has required that there be ten-digit dialing between and within area codes in the geographic area covered by an area code overlay. This means that every local call previously dialed using seven digits, even if it is a call to a customer with the same area code as the caller, must be dialed using ten digits.

AREA CODE 919

On December, 10 1999, NeuStar, Inc., in its role as the NANPA, filed with the Commission an industry recommendation for relieving area code 919 in North Carolina. The industry held a meeting in Morrisville on November 4, 1999, where participants considered several relief alternatives to furnish relief before exhaust of 919, including a distributed overlay, a concentrated growth overlay, and four different geographic splits. More specifically, the participants considered the following alternatives:

Alternative 1 — Distributed overlay placed over the entire 919 area code.

Alternative 2 — Concentrated growth overlay with Area A consisting of Raleigh, Cary, Cary-RTP, and Durham rate centers. Area B would include all remaining exchanges in the 919 area code region.

Alternative 3 — North/South geographic split with boundary line running along rate center boundaries east of Durham, Raleigh, and Angier. Area A would be west of the split line and Area B east of the split line.

Alternative 4 — Geographic split with Area A consisting of Raleigh, Cary, Cary-RTP, and Durham rate centers. Area B would include all remaining exchanges in the 919 area code region.

Alternative 5 — East/West geographic split with boundary line running along rate center boundaries near Raleigh south of the following rate centers: Chapel Hill, Durham, Cary, Raleigh, Wake Forest, and Louisburg. Area A would be north of the split line and Area B south of the split line.

Alternative 6 — Approximate balanced life split with boundary line running along rate center boundaries including the Cary, Cary-RTP, Raleigh, Clayton, Selma, Smithfield, Kenly, Fremont, Goldsboro, Princeton, Grantham, and Mount Olive rate centers. Area A would be west and north of the split line and Area B east of the split line.

The industry participants reached unanimous consensus to recommend to the Commission the distributed overlay over the entire 919 geographic area as the most suitable relief plan for the 919 area code. This option would "overlay" a new area code over the 919 geographic area and use the existing 919 boundary lines. Existing customers would retain the 919 area code, and would not have to change their numbers. As telephone numbers in the 919 area code are used, new customers from all industry segments would be assigned telephone numbers from the new area code. Industry participants also reached consensus to recommend a ten-digit dialing plan, consistent with the FCC regulation requiring ten-digit dialing between and within the old area code and the new overlay code as well as from surrounding area codes into the 919 area to eliminate the need for protecting NXXs.

On June 20, 2000, the Commission issued an Order requesting comments on the industry's proposed overlay relief plan and geographic split alternatives. Comments and reply comments were received from both the using and consuming public and the industry. Comments from the industry were consistently in favor of the recommended overlay. Letters from the public were generally, although not unanimously, opposed to the ten-digit dialing required by the overlay.

On August 29, 2000, NANPA declared the 919 area code to be "in jeopardy," meaning that in the absence of NXX code rationing, the supply of available NXX codes would exhaust before relief could be implemented. A jeopardy rationing plan is currently in place limiting the assignment of the remaining NXXs to a maximum of ten per month.

Public hearings were scheduled by Order dated November 22, 2000, and were held on the evening of January 16, 2001, and the morning of January 17, 2001, in Commission Hearing Room 2115, Dobbs Building, Raleigh, North Carolina.

Ten witnesses from the public testified at the hearings. Two of those witnesses, Ken Henke of Holly Springs and David Baratta of Cary were associated with alarm or security companies. Both of those witnesses stressed the alarm industries need for as much time as possible to allow reprogramming of automatic dialing equipment. In general, the remaining public witnesses expressed a preference for a geographic split and, in particular, for seven-digit dialing.

Thomas C. Foley, NPA Relief Planner, Eastern Region, and Douglas A. McCullough, BellSouth, Inc., appeared to present and explain the industry recommendation.

SUMMARY OF COMMENTS AND TESTIMONY

NANPA. NANPA[1], based upon industry consensus, favors the distributed overlay relief option. NANPA, representing the industry consensus, states that all of the geographic split alternatives are less efficient and more burdensome than Alternative 1 calling for an all services distributed overlay. With respect to Alternatives 3 and 5, NANPA points out that these geographic splits would have severely imbalanced exhaust projections among the designated Areas A and B. For example, in Alternative 3, Area A is projected to exhaust in 2.4 to 4.8 years, while Area B is projected to exhaust in 34-50 years. Similarly, in Alternative 5, Area A is projected to exhaust in 3.4

[1]As the neutral third-party administrator, NANPA stated that it has no independent view regarding the relief options selected by the industry.

to 6.8 years, while Area B is projected to exhaust in 25 to 50 years. Under NPA Relief Planning Guidelines, such a wide gap exceeding 15 years between the two proposed areas in the split is to be avoided. The industry has further agreed that Alternatives 4 and 6, while more balanced, would entail the inherent difficulties with a geographic split. In particular, and especially with regard to Alternative #6 which would split Wake County, political boundary disputes are likely to arise as lines are drawn, communities of interest will be divided by the new area code, and consumers will face confusion in having to dial local calls with 7 digits in some instances and 10 digits in others. NANPA further states that because geographic splits provide more limited relief, additional geographic splits will become necessary in the future, thereby shrinking the geographic base for existing NPAs and requiring more and more 10-digit dialing. NANPA has rejected the option of a three-way geographic split because it would unnecessarily waste NPAs where such resources are scarce.

NANPA, on behalf of the industry, reached a consensus to reject Alternative 2, calling for a concentrated growth overlay because such an overlay would entail many of the same difficulties as a geographic split; namely, boundary disputes, mixed 7 and 10-digit dialing and splitting communities of interest. At the public hearing held in this docket, NANPA further advised the Commission that at this juncture, a concentrated growth overlay is not a viable option because insufficient time remains before the exhaust of the 919 NPA to implement this alternative.

According to NANPA and the industry, a distributed overlay is a more long-lasting, efficient and less burdensome measure to relieve area code 919. The distributed overlay will maximize the use of NXXs because of the elimination of protected codes and will provide a longer period of relief with an easier method of addressing the eventual exhaust of the overlay NPA. Moreover, with a distributed overlay: (1) the geographic size of the existing 919 area code will not shrink; (2) existing customers may keep their area codes, without the need to change business stationery, advertising and other printed materials; (3) political and public involvement in deciding the boundary of a split will be avoided; and (4) area code relief will be more long lasting.

The chief disadvantage of the distributed overlay is the mandatory ten-digit dialing required pursuant to the FCC's order. This disadvantage is minimized, however, because each of the geographic splits will require consumers to use ten-digit dialing for local calls to nearby areas separated by a new area code, and further, as the new NPAs exhaust, additional splits will occur rendering 10-digit dialing more and more prevalent.

Because of the proximity of the exhaust of the 919 NPA, the industry has recommended an implementation schedule that would allow the industry time to prepare advertisements regarding the change, begin permissive dialing, allow auto-dialers (such as alarms) to be reprogrammed for 10-digit dialing and educate customers before mandatory ten-digit dialing may begin.

<u>Cardinal Communications of North Carolina, Inc. (Cardinal Communications)</u>. Cardinal Communications is an Internet service provider (ISP) using DSL technology. Cardinal Communications supports the industry's recommendation of a distributed overlay without change. Cardinal Communications supports the position that while mandatory 10-digit dialing is a disadvantage, a mix of seven and ten-digit dialing that would be present with any of the proposed geographic splits would also be a disadvantage to the public.

Incumbent Local Exchange Carriers in the 919 Area Code (ILECs). The ILECs in North Carolina's 919 NPA consist of Alltel Carolina, Inc., BellSouth Telecommunications, Inc., GTE South Incorporated, MEBTEL, Inc., Carolina Telephone and Telegraph Company, and Central Telephone Company. The ILECs in the 919 NPA support the industry's recommendation of a distributed overlay. The ILECs point out the advantages of the distributed overlay, including the avoidance of changing existing numbers, expenses associated with changing stationery and printed business materials and political boundary disputes. With particular importance to ILECs, the distributed overlay relief is preferred to the concentrated growth overlay because the latter would entail customer confusion because of the mix of seven and ten-digit dialing, current monitoring methods are not sufficiently accurate to determine the exhaust date for territories outside the concentrate growth areas and the same political disputes would exist in attempting to draw lines for the concentrated growth area.

Alltel Communications, Inc. (Alltel). Alltel filed separate comments supporting the industry's recommendation of the distributed overlay relief plan and concurring in the ILECs' comments.

Broadband Office Communications (BBOC). BBOC does not object to the industry's recommendation and makes no changes.

AT&T. AT&T fully supports the implementation of a distributed overlay as a method of relief for the 919 area code and does not recommend any changes to the industry recommendation. AT&T further comments that the other five alternatives would present equal, if not greater, inconvenience to the public because communities of interest would be divided and local calling areas would be split, creating a mix of seven and ten-digit dialing. Moreover, several of the proposed geographic splits (Alternatives 3 and 5) would result in significantly unbalanced projected lives of the resulting area codes and would not provide sufficient relief for the 919 area code.

Verizon Wireless. Verizon Wireless supports the industry's recommendation of implementing a distributed overlay in 919 area code. Relief in the form of a geographic split would create the problem of splintering North Carolina into smaller parts, would cost millions of dollars in expenses for businesses and residents who would have to change their area codes with a geographic split, would entail political boundary disputes and would not provide the longevity of an overlay. An overlay, on the other hand, is consistent with current intrastate dialing practices and would allow more flexibility to assign resources once number conservation measures are adopted. An overlay would further be much less burdensome on wireless customers in particular, who would be required to have their cellular telephones reprogrammed in the event of an area code change. Verizon Wireless further points out that the Commission has already required a distributed overlay in area code 704, and that public utility commissions in New York, Virginia, Maryland, Georgia, Pennsylvania, Texas, Illinois, Connecticut, Florida, Michigan, Oregon and Colorado have adopted all-service overlays.

WorldCom, Inc. While WorldCom generally advocates geographic splits as the most pro-competitive method of area code relief, WorldCom supports the industry recommendation of distributed overlay relief in the case of the 919 area code.

Public Response to the Proposed Alternatives. The Commission has received approximately 75 letters from members of the public, with the large majority favoring a geographic split, primarily because of the ten-digit dialing required when an overlay is implemented. In addition, following the public hearings, the Commission received a petition from consumers requesting a geographic split rather than the distributed overlay because of the ten-digit dialing requirement. The Consumer Petition was signed by over 175 residents. A number of the written public comments also expressed concern that the overlay would be confusing and that any new NPA should be reserved for mobile numbers. Others expressed a preference for the alternatives of a concentrated growth overlay and a distributed overlay. Other consumers expressed the desire to retain their existing NPAs. One business customer expressed concern at the cost of changing his letterhead and stationery in the event of a geographic split that designated his address in a new area code. The Commission has also received a written submission from the Chamber of Commerce of Granville County, requesting that the county remain in one area code and not have multiple area codes.

In addition to these written submissions, seven residential consumers testified at the public hearings in this docket in favor of a geographic split: Anthony Lea, Matt Horrer, David Thompson, Edward Gehringer, John Marsil, James Scarborough and Steven LaSala. These residential consumers oppose a distributed overlay because of the requirement of ten-digit dialing and some have expressed the added concern that an overlay will strip an area code of its geographic identity, making it more difficult to remember which area code applies. One consumer, Kelly Donaldson, did not oppose a distributed overlay, even with mandatory ten-digit dialing.

Public Staff's Reply Comments. In its reply comments, the Public Staff states that it supports the all services distributed overlay plan recommended by the industry. Although the Public Staff recognizes the inconvenience and confusion that may arising with mandatory ten-digit dialing, the Public Staff believes that the recommended plan is the most efficient, forward looking and equitable approach for relief in area code 919.

Response of the Alarm/Security Industry. At the public hearings held in this docket, two individuals owning alarm and security companies testified regarding the impact of a distributed overlay on their businesses. Both individuals favored a geographic split because of the cost involved in reprogramming customer systems to allow for mandatory ten-digit dialing. In the event the Commission determines that a distributed overlay should be adopted as the relief plan for 919, these individuals have asked the Commission to allow an appropriate grace period for reprogramming to occur.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After carefully considering all of the relevant factors and the comments, reply comments, and testimony submitted in this proceeding, the Commission concludes that a distributed overlay should be adopted to relieve area code 919. This is a difficult decision, and one which the Commission makes very carefully and with high expectations of the industry that has so emphatically supported an overlay. In the Commission's view, there are disadvantages and inconveniences associated with both a geographic split and with an overlay, and the Commission has the difficult task of attempting to discern what relief method will be least inconvenient and burdensome for consumers while providing the most significant and long-lasting relief for the area code.[1] The overlay is certainly not an ideal option, primarily because of the FCC requirement that all local calls must be dialed with ten digits when an overlay is implemented. However, the primary benefit of the overlay is that it does spare all current customers in the 919 territory from the inconvenience and expense of changing their current telephone numbers.

Moreover, while there are many uncertainties in addressing area code relief, the overlay appears to have an advantage because it makes NXX codes from the new overlay area code available throughout the territory currently served by 919. As some commenters note, successful implementation of the overlay is less dependent on forecasts, and trying to determine where increased demand for numbers will occur. The industry states in its comments that a distributed overlay uses numbering resources as efficiently as possible because each carrier in the relief area has access to the complete supply of new numbers. There is no need to draw a line that determines where new numbers will be available. Because it is difficult to predict where there will be the most demand for numbers, it is difficult to determine where to set the boundary for a geographic split to make the most efficient use of the numbers. With a geographic split, additional area code relief could be necessary soon for some citizens, if there is significantly higher demand for numbers on one side of the split than on the other. Several citizens who wrote letters to the Commission opposing the overlay were under the impression that if a geographic split were implemented, no additional relief would be necessary for a considerable time to come, but that may not necessarily be the case. The Commission certainly is interested in having the chosen area code relief method last as long as possible for all of the citizens in the current 919 area code, and it appears that the overlay is the better choice from that perspective. We believe that the recommended overlay is the most efficient, forward-looking, and equitable approach available for achieving area code relief in the 919 area under the present circumstances.

Until recently, a geographic split was attractive, despite its other problems, as a means of introducing a new area code because seven-digit dialing could be maintained for the great majority of routes within the area. Today, however, as the geographic area assigned to area codes has been reduced by successive splits, a much greater percentage of the routes within an existing area must be converted to ten-digit dialing with more subscribers being affected by the mix in dialing. Ten-digit dialing is necessary to eliminate protected NXX prefixes so as to assure more efficient use of numbering resources. Continuing to protect old NXXs, and new NXXs as they are introduced, would significantly reduce the life of the area codes after the split. Recognizing this effect on area code life, the Commission required that all cross-NPA boundary expanded local calling area routes created as a result of the geographic splits implemented in 1997 and 1998, be changed to ten-digit dialing. Earlier, in 1994, in an effort to extend the life of existing area codes, the Commission had

[1] Other states are facing the same dilemma. Seventeen states, in addition to North Carolina, currently employ or have plans pending to implement overlays. Those states are Illinois, Maryland, Michigan, Virginia, Oregon, California, Florida, New York, Texas, Colorado, Georgia, Pennsylvania, Ohio, Connecticut, Washington, Massachusetts, and Missouri.

acted to implement ten- rather than seven-digit dialing on all future cross-NPA boundary local calling routes, including extended area service (EAS) routes.[1]

The life estimates furnished by the industry for the various split alternatives assume that codes will not be protected and that ten-digit dialing of all local (basic local and expanded local) calls made between the old area code and the new split area code would be implemented. Many, if not all, of these routes are currently dialed using seven digits.

The effect of this ten-digit dialing conversion in a split scenario can be demonstrated by analyzing the effect of split Alternative 6 on the Raleigh exchange. This geographic split alternative is attractive compared to the other split alternatives because it generates nearly equal estimated lives of the old area code and the new area code after the split. Under Alternative 6, the Raleigh area would be separated from the Durham and Chapel Hill areas. Based on local calling area information on file with the Commission, this would result in Raleigh customers having to dial ten-digits for calls made to 19 of the 25 or 76% of the exchanges (EAS or expanded local) that they can call today using seven digits. To put it a different way, today there are a total of 469 NXXs that Raleigh customers can call locally using seven digits. Under split Alternative 6, 229 or 49% of those NXXs would have to be dialed using ten digits. The number of local NXXs available to Raleigh customers would make it virtually impossible to remember which local calls must be dialed with seven digits and which with ten digits. Further, there is no discernible pattern that could be used to guide subscribers in distinguishing which NXXs require only seven digits and which require ten digits. Even some consecutively numbered NXXs must be dialed differently. For example, while 210, 212, 215, 218, and 219 are Raleigh NXXs which could be dialed with seven digits, 214, 216 and 217 NXXs are Chapel Hill or Knightdale NXXs which would require using ten digits. The evidence indicates that some degree of mixed dialing, that is dialing some local numbers with seven digits and other numbers with ten digits, would result from any reasonable split alternative and would affect all subscribers in the area in generally the same way. We believe that this level of mixed dialing would result in considerable customer frustration and confusion. We believe that the confusion which would accompany mixed dialing in a geographic split scenario along with the other disadvantages of a geographic split makes the split scenarios less attractive than the overlay.

The Commission further notes that FCC requirements prohibit implementation of technology-specific relief plans. For that reason, the Commission does not have the authority to assign a new area code to a specific technology, such as the wireless industry. Furthermore, the Commission is unable, as some commenters have proposed, to add a fourth digit to the NXX codes because that would require total revision of the NANP. Such action is beyond the jurisdiction of this Commission to require.

Recently, the Commission delayed the implementation of the overlay in the 704 area code to allow the alarm industry more time to reprogram systems to be ten-digit dial compatible. To avoid a similar problem in implementing the overlay in the 919 area code, the Commission requires that all

[1]Furthermore, consistent with the decision entered by the Commission in Docket No. P-100, Sub 137a on September 15, 1999, the practice of protecting or not assigning certain NXX codes in order to preserve current seven-digit inter-NPA dialing must cease. In order to maximize the amount of numbering resources available throughout the geographic territory currently served by the 919 area code, North Carolina service providers will be required to eliminate protected codes for current seven-digit inter-NPA dialing arrangements between 919 and other area codes.

educational information disseminated by the service providers in the 919 area code specifically alert the alarm industry and its customers to the need to reprogram alarm systems to be ten-digit dial compatible before ten-digit dialing becomes mandatory. The information should contain schedules for implementing the overlay, including specific dates for permissive dialing, and should state how long the alarm industry has, beginning with permissive dialing, to reprogram their systems. Of course another option to the alarm industry members is to reprogram using 800 numbers. Conversion to 800 number dialing can be started immediately, prior to the implementation of permissive dialing.

The Commission requests that the North Carolina Alarm Systems Licensing Board (Board) provide assistance in ensuring that all affected alarm companies receive notice of the pending change, encouraging them to immediately begin their efforts to reprogram their systems as soon as permissive dialing begins or sooner using 800 numbers. The Commission also requests that the Board provide to the Commission confirmation that its licensed companies have received the notification and certify well in advance of the implementation date that the licensed companies will be ready for mandatory ten-digit dialing. The Commission also notes that the North Carolina Burglar & Fire Alarm Association has been providing information on this issue to its members and encouraging them to act promptly to prepare for the pending change. All parties are requested to extend their cooperation and assistance to this and other alarm and security industry trade associations.

Further regarding the alarm situation, the Commission requires that all disseminated educational information alert alarm customers of the pending change, urging them to make sure their alarm systems are properly programmed before mandatory ten-digit dialing begins and to cooperate fully with their alarm company in this effort, including allowing timely access to their premises by their alarm company if necessary.

With regard to the rationing plan currently in effect, the Commission directs the industry to make every reasonable effort to extend the estimated life of the 919 area code by requesting only those NXXs which are absolutely necessary to meet growth and identifiable market requirements. Also, the Commission directs the industry to continue the practice of sequential numbering by thousands-blocks within the NXXs currently assigned. The practice of assigning all available telephone numbers within an opened thousands-block before opening another thousands-block should be strictly adhered to by all industry participants. Complete utilization of all of the numbering resources at the thousands-block level before opening another thousands-block will provide the industry with an inventory of clean or lightly-contaminated blocks for the coming environment of thousands-block pooling. The industry's complete cooperation on these two measures will extend the service life of the 919 NPA for as long as possible without jeopardizing the availability of numbers to the public in general.

Not later than 30 days after the release of this Order, an "Implementation Report" should be filed in this docket for informational purposes. All telecommunications service providers who are parties to this docket shall be responsible for generating the Implementation Report, and the Commission strongly encourages all current holders of NXX codes and service providers planning to obtain NXX codes in the current 919 area code to participate. The filing should describe the scope, methods, and estimated costs of the companies' customer education efforts. It should describe the overlay implementation, including the length of the permissive dialing period, and should discuss fully the service providers' plan for elimination of protected NXX codes. It should provide complete information on any other implementation issues. The Commission requests that the implementation plan allow for as long a permissive dialing period as possible, to allow consumers, and particularly alarm industry members, sufficient time to adjust to dialing ten digits for all local calls. The filing should include a calendar of all implementation and customer education activities, up to and including the introduction of the first number with the new area code. The filing should also include drafts of any bill inserts that the companies intend to provide to their customers explaining the overlay and its impacts on customers. Finally, the filing should include the name of one or more persons that the Commission can contact with questions about the Implementation Report, particularly about customer education activities.

Finally, the Commission will continue to: (1) vigorously pursue the benefits of its number reclamation activities in the 919 NPA; (2) carefully review NANPA assignment and utilization data in the 919 NPA to ensure that conservation measures are being observed; and (3) pursue thousands-block number pooling to achieve all possible numbering resource management benefits applicable to the 919 NPA. The Commission will continue to stress the conservation of numbering resources as a major requirement due to the current demand for numbering resources occurring nationwide, as well as what is being experienced within the State of North Carolina. The FCC has provided the Commission with delegated authority for thousands-block number pooling in the 919 NPA and, therefore, it is the Commission's intent to implement thousands-block number pooling in the 919 NPA as soon as practical in order to extend the life of that NPA to the maximum extent possible. The Commission will issue an Order in the near future addressing the implementation of thousands-block number pooling in the 919 NPA. All industry participants are directed to cooperate in and actively promote this endeavor.

IT IS, THEREFORE, ORDERED as follows:

1. That a distributed overlay is hereby adopted to provide relief for the current 919 area code in North Carolina.

2. That it is the Commission's goal and intent to prolong the service life of the 919 NPA for as long as possible through the implementation of extensive conservation measures (specifically thousands-block number pooling), to include the issuance of an Order in the near future addressing the implementation of thousands-block number pooling in the 919 NPA.

3. That the practice of protecting or not assigning certain NXX codes in order to preserve current seven-digit inter-NPA dialing shall cease.

4. That all educational information disseminated by the service providers in the 919 area code shall specifically alert the alarm industry and its customers to the need to reprogram alarm systems to be ten-digit dial compatible before ten-digit dialing becomes mandatory.

5. That the North Carolina Alarm Systems Licensing Board is requested to provide assistance in ensuring that all affected alarm companies receive notice of the pending change, encouraging them to immediately begin their efforts to reprogram their systems as soon as permissive dialing begins or sooner using 800 numbers. The Board is requested to take the following actions:

a. Provide both confirmation to the Commission that its licensed companies have received the notification and certification well in advance of the implementation date that the licensed companies will be ready for mandatory ten-digit dialing.

b. Ensure that all disseminated educational information shall alert alarm customers of the pending change,. urging them to make sure their alarm systems are properly programmed before mandatory ten-digit dialing begins and to cooperate fully with their alarm companies in this effort, including allowing timely access to their premises by their alarm companies if necessary.

6. That, not later than 30 days after the release of this Order, an Implementation Report shall be filed in this docket for informational purposes. All telecommunications service providers who are parties to this docket shall be responsible for generating the Implementation Report, and the Commission strongly encourages all current holders of NXX codes and service providers planning to obtain NXX codes in the current 919 area code to participate.

a. That the Report should describe the scope, methods, and estimated costs of the companies' customer education efforts. It should describe the overlay implementation, including the length of the permissive dialing period, and should discuss fully the service providers' plan for elimination of protected NXX codes.

b. That the Report should provide complete information on any other implementation issues. The filing should include a calendar of all implementation and customer education activities, up to and including the introduction of the first number with the new area code.

c. That the Report should also include drafts of any bill inserts that the companies intend to provide to their customers explaining the overlay and its impacts on customers.

d. That the Report should include the name of one or more persons that the Commission can contact with questions about the Implementation Report, particularly about customer education activities.

ISSUED BY ORDER OF THE COMMISSION.
This is the 13th day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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DOCKET NO. P-100, SUB 140

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Rulemaking, to Revise Billing and	)	
Collections Procedures for Telecommunications	)	ORDER RULING ON SPRINT
Companies Regarding Local Disconnection and Toll	)	COMPLIANCE ISSUES
Denial	)	

BY THE COMMISSION: On April 3, 2000, the Commission promulgated Rule R12-17, relating to the disconnection, denial, and billing of local telephone service. On July 19, 2000, the Commission directed that Carolina Telephone and Telegraph Company and Central Telephone Company (collectively, Sprint) and all other incumbent local exchange companies (ILECs) file reports by November 1, 2000, on their compliance with Rule R12-17(i). In its report, Sprint noted that it had recently adopted a new customer billing format known as the Millennium Bill and requested Commission approval.

On March 2, 2001, the Attorney General filed Comments Regarding Compliance Reports, stating, among other things, that it believed that Sprint's sample bill fell short of the regulatory requirements in two respects. First, under Rule R12-17(i)(2)(C), toll and unregulated charges must be clearly identified on the customer's bill:

> **(C) Language, prominently displayed, must also appear on the bill clearly identifying those charges for which nonpayment will not result in disconnection of local service, as well as those charges for which nonpayment will not result in disconnection of any regulated service.**

Sprint attempted to identify toll charges on its bill by a symbol and nonregulated charges by a § symbol; however, several toll and nonregulated charges shown on the sample bill were not marked with the appropriate symbol. Second, Sprint failed to state clearly and consistently the amount owed by the customer for local services. The Attorney General noted in its comments that Sprint intended to correct the problems. The Attorney General also briefly addressed matters concerning the billing statement and disconnect notice filed by BellSouth Telecommunications, Inc. and the bill insert filed by Concord Telephone Company.

On April 9, 2001, Sprint filed a reply to the Attorney General's comments, including a revised version of the Millennium Bill. The bill specifies the amount due for local service correctly and it also appears to eliminate most of the errors in the use of the symbols to identify the toll and nonregulated charges.

On May 3, 2001, the Public Staff filed its Response to the Comments of Sprint and the Attorney General. The Public Staff believed that, while Sprint has made efforts to correct problems, it still falls short. In particular, although the sample bill breaks down the current month's charges to show the amounts due for local, toll and nonregulated service, it does not break down the customer's arrearage from previous months in this manner. Consequently, the customer cannot easily determine how must he must pay to avoid disconnection of service or avoid toll denial. The Public Staff argues that Sprint has failed fully to implement Rule R12-17(i)(2)(C) which states: **Language, prominently displayed, must also appear on the bill clearly identifying those charges for which nonpayment will not result in disconnection of local service, as well as those charges for which nonpayment will not result in disconnection of any regulated service.**

The Public Staff concedes that the rule does not speak to the past due amount separately. However, the customer cannot ascertain how much of the past due amount must be paid to retain local service and how much must be paid to retain any regulated service unless the local and regulated portion of the total past due amount are separately identified. Interestingly, Sprint has properly broken down the past due amount into its local, toll, and nonregulated components in its disconnect notice. It is the Public Staff's view that this information must appear not only on the disconnect notice but on the bill itself.

The Public Staff went on to identify scenarios in which the inclusion of past due detail in the billing statement could alleviate confusion. One is the case in which the customer has already received a disconnect notice which states the amount he needs to pay to preserve his local service, the amount he needs to pay all regulated service and the full amount of the regulated and nonregulated charges, and, while he is attempting to make payments on all or part of his bill to avoid disconnection, he receives another billing statement, which would include the total charges in one lump sum. Another instance is when a disconnect notice has not been issued for a past due amount from a previous bill and the past due amount is simply brought forward as a single amount to the new bill. A subscriber who is trying to make a decision on what to pay based upon the second bill may be misled that he has no option on preserving his local or regulated service other than to pay the full past due amount. Further difficulty may arise if the subscriber has made a partial payment since his last bill was issued and the past due balance as shown on Page 1 of Sprint's billing statement differs from the amount which was broken down on the subscriber's last bill.

The Public Staff believed that Sprint's sample bill also violates Rule R12-9(b) and (c) because of its failure to disclose the billing date and past due date. Rule R12-9(b) states: **All bills for utility service are due and payable as of the billing date, or if not received by said billing date, upon receipt. The billing date shall be printed on the bill and the bill shall be placed, postage prepaid, in the U.S. Mail (or if the mail is not used, delivered to the customer) prior to or no later than the billing date.** Rule R12-9(c) states: **The past-due or delinquent date is the first date upon which the utility may initiate disconnect proceeding under NCUC Rule R12-8. The past due or delinquent date shall be disclosed on the bill and shall not be less than fifteen (15) days after the billing date. In the event the utility fails to place the bill in the mail (or deliver it as in paragraph (b) above) prior to or on said billing date, the consumer shall have the right to require that the utility adjust the billing date by the number of days by which the postmark (or delivery as in paragraph (b) above) exceeds the original billing date.** While the second page of the sample bill states that the due date is 15 days after Sprint places the bill in the U.S. Mail, this explanation is in small type and can be easily overlooked; and, moreover, it is inconsistent with the rule that states that bills are due immediately upon receipt and are past due or delinquent on the date that should appear on the bill, not less than 15 days after the billing date. Sprint should show the billing date on the first page of the bill and replace the phrase "Date Due" with wording more consistent with the rules such as "Past Due Date," "Current Charges Due Before," "Date Delinquent," or the like.

According to the Public Staff, Sprint's sample bill also violates Rule R12-17(i)(2)(B) which provides: **(B) Language must appear on the bill clearly explaining the consequences of failing to pay particular charges shown on the bill. Such language must be prominently displayed either on the summary page of the bill or in close proximity to the specific charges to which it applies.** On the sample bill, the explanation of the consequences of failing to pay particular charges appears on the second page, rather than on the summary page or the pages where the specific charges are shown.

The Public Staff also criticized Sprint's use of the symbols to identify toll and nonregulated charges. Rule R12-17(i)(2)(F) provides, nonregulated charges are ordinarily required to be listed on a separate page or section. An alternative format, such as Sprint's use of the symbols, can only be adopted with the Commission's approval. The Public Staff believes that the symbols are potentially confusing. Rule R12(i)(2)(F) states as follows: **(F) Nonregulated charges will be shown: (i) on a separate page of the bill; or (ii) in a separate section of the bill, if the charges are clearly and prominently labeled as such and the section in which they appear is set apart from the regulated charges section; or (iii) subject to the approval by the Commission, using other formats, so long as the proposed format results in appropriate consumer understanding regarding the nature of the charges. On the same page where charges appear, customers will be notified that they cannot lose local or other regulated service for nonpayment of these charges, except in the case of bundled service offerings as identified in Rule R12-17(a)(3).**

The Public Staff agrees with the Attorney General's comments on the billing statement and disconnect notice filed by BellSouth Telecommunications, Inc. and the bill insert filed by Concord Telephone Company. However, the Public Staff has other significant reservations about BellSouth's billing statement which it will address later.

The Public Staff, therefore, recommended that the Commission not approve Sprint's Millennium Bill format and that it not give blanket approval to any bill format on the basis of a limited number of sample bills.

<u>Sprint's Response</u>

On June 4, 2001, Sprint filed its Response to the Public Staff's Response above. Sprint described its Millennium Bill project in some detail and noted that it had been warmly received by customers. Sprint also noted that it had participated in the process which led up to the Rule R12 and observed that the Attorney General had found its modifications to be satisfactory.

Sprint argued that the Public Staff was too ready to find "requirements" in Rule R12 which are not there. These requirements will serve to confuse customers more than to enlighten them. Specifically, Sprint responded as follows:

<u>Paragraphs 4, 5, and 6.</u> The Public Staff alleges that the Sprint bill has shortcomings related to disconnection of local service--specifically, that the Sprint sample bill does not break down the

customer's arrearage from previous months to show the amounts due for local, toll, and nonregulated service. Sprint cited to Rule R12-17(i)(2)(c) which provides that there must be language clearly identifying those charges for which nonpayment will not result in the disconnection of local service as well as those charges for which nonpayment will not result in disconnection of any regulated service. Sprint notes that the rule does not require that past due amounts be broken down on the bill as the Public Staff assumes. Sprint also pointed out that the first time a customer views new charges appearing on a bill there is full disclosure of the type of charge and specific language advising the customer of the consequences of failure to pay. Also, before suspension of any service, customers receive a Disconnect Notice which provides a breakdown. Other major telephone companies do not break down past due charges.

Paragraph 7. The Public Staff acknowledged that Sprint properly breaks down the charges on the Disconnect Notice but reiterated its erroneous conclusion that Rule R12-17(i)(2)(c) requires that the past due charges be broken down on the bill.

Paragraphs 8, 9, 10, and 11. These discuss examples of extremely unusual circumstances to justify the breaking down of past due charges on the bill. Customers, however, know that prior to suspension of service, they will receive a Disconnect Notice. Sprint does not believe that, in light of all the circumstances, the Public Staff's view has either legal or practical merit.

Paragraph 12. The Public Staff has asserted that Sprint is in violation of Rule R12-9(b) because Sprint substitutes the words "Monthly Statement" for "Billing Date" and because Sprint does not show the billing date and the past due date. The Public Staff also claims that Sprint is in violation of Rule R12-9(b) and (c) stating that bills are due immediately upon receipt and are past due or delinquent (not merely due) on the date that should appear on the bill, not less than 15 days after the billing date. Sprint believes that the term "Monthly Statement" for the term "Billing Date" is within the meaning of the rules, but is willing to replace the term "Date Due" with "Current Charges Due Before." The date on the right of the bill is the date that Sprint actually prints the bill, and logistics prevent that date from being the same as it is mailed, as the Public Staff insists. It is crucial for Sprint to maintain the current date that appears on the bill because that date acts as a starting point for Sprint customer services representatives in providing information to customers. Sprint also noted that the Public Staff had failed to mention that the second part of Rule R12-9(c) has a particular provision in the event the utility fails to place the bill in the mail prior to or on the billing date. The consumer then has the right to require the utility to adjust the billing date by the number of days by which the postmark exceeds the original billing date. Sprint in fact automatically extends the past due date to make allowances for the delay in mailing, a common practice among utilities. Consumers are informed of this on page 2 of the bill.

Paragraph 13. The Public Staff claims that Sprint's sample bill violates Rule R12-17(i)(2)(B) which provides that an explanation of the consequences of failing to pay particular charges on a bill must appear either on the summary page of the bill or close to the specific charge to which it applies. Sprint has this information on page 2, which is a continuation of the summary pages. In addition, Sprint places directive language at the bottom of each page where the specific charges appear.

Paragraph 14. The Public Staff has argued that several charges on the sample bill--as, for example, federal and state taxes--are marked with the section symbol for nonregulated service although in fact these are local or toll charges. Sprint admitted that this was a temporary shortcoming that it is working to overcome. In the meantime, this shortcoming will not jeopardize any customer's local or long distance service.

Paragraph 15. The Public Staff claims that it is inappropriate to grant approval to the Millennium Bill format on the basis of a sample bill. Sprint argued that it is not seeking, nor do the rules require blanket approval of the Millennium Bill. Rule R12-17(i)(2)(F)(iii) allows the Commission to approve an alternative bill format to identify non-regulated charges. This is what Sprint is seeking.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The dispute between the Public Staff (and, to a lesser degree, the Attorney General) and Sprint centers around certain aspects of Sprint's Millennium Bill, which Sprint is using nationwide. The controversies pertain to the construction of certain rules concerning whether a particular rule, either explicitly or by reasonable implication, give guidance as to how the telephone bill is to be constructed. The primary concern in construing a particular provision should be whether the proposed bill language and format reasonably convey the information they are required to convey to the customer. In addition, in cases where the rules do not strictly require certain information but such information has a high probability of being useful to the consumer without being overly burdensome to the carrier, carriers are encouraged to supply it, especially if requested to do so by the Public Staff or Attorney General.

In the case at hand, the first dispute centers around whether Sprint should break down the customer's arrearage from previous months. Sprint disputes the Public Staff's argument that Rule R12-17(i)(2)(C) requires this per se and argues that the customer will receive adequate information and notice at other appropriate times. Before suspension of any service, customers will receive a Disconnect Notice which will provide a breakdown. The Commission agrees with Sprint that Rule R12-17(i)(2)(C) does not require or reasonably imply that arrears must be broken down from previous months. However, this may be useful information, and Sprint should consider providing such information as its billing system evolves.

The second dispute centers around Sprint's utilizing the words "Monthly Statement" (which is actually the printing date rather than the mailing date) for "Billing Date" and Sprint's not showing the billing date and the past due date. These are argued to be violations of Rule R12-9(b) and (c). Sprint has indicated that it is willing to replace the term "Due Date" with "Current Charges Due Before." Sprint also justified on the basis of logistics and customer service efficiency the placement of the monthly statement date instead of the mailing date. The Commission has examined the relevant rules and the Sprint bill attached to its Response. While Rule R12-9(b) provides that the indicated billing date should be the same as the mailing date, Sprint points out that Rule R12-9(c) has a proviso that, if the carrier fails to place the bill in the mail on or before the billing date, then the billing date can be adjusted by the number of days by which the postmark exceeds the original billing date. In effect, Sprint has automatically extended the past due date to make allowances for delays in mailing. Sprint further represented that this is a common practice among utilities. In the sample bill, Sprint appears to have left ample time (19 days) between the Monthly Statement Date and the

Date Due date for mailing and delivery to the customer with 15 days to spare. The Commission further notes that on page 2 of the bill, Sprint disclosed under the title "Important Information" that the Due Date printed on page 1 is fifteen days after Sprint placed the bill in the mail and that the charges are past due and delinquent after the Date Due. Despite the Public Staff's implication, this notice does not sem to be in extraordinarily small type or is otherwise being concealed from the customer.

In summary, the Commission does not believe that it is a violation of Rule R12-9(b) and (c) construed together that the Monthly Date is not the same as the mailing date as long as there is adequate time allowed for the printing, mailing and delivery of the bill to the customer. The Commission is not overly exercised about the term "Monthly Statement" over "Billing Date," but Sprint is urged to make that change if it is not overly burdensome to do so. The Commission also notes that Sprint has agreed to replace the term "Date Due" with the term "Current Charges Due Before."

The third dispute concerns whether the Sprint Bill violates Rule R12-17(i)(2)(B) by providing information as to the consequences of failure to pay on the second page. Sprint argues that page 2 is a continuation of the summary pages and, in addition, Sprint places directive language at the bottom of each page where the specific charges appear. The Commission agrees with Sprint that its placement of the warning on page 2 does not violate the rule because page 2 is a continuation of the summary pages.

The fourth dispute relates to the use of symbols to denote toll charges and unregulated charges. The Public Staff and Attorney General criticized their inconsistent use--e.g., federal and state taxes are marked with the section symbol for nonregulated service although they are part of local or toll charges. The Public Staff considered the symbols to be an "alternative format" which can only be adopted with the Commission's permission. The Commission believes that the symbols should be used clearly and consistently. Sprint recognizes that there are shortcomings here and is working to overcome them. The Commission concludes that Sprint be required to demonstrate that it is using the symbols clearly and consistently or desist from using them. Sprint should report whether it has accomplished this by January 2, 2002.

Finally, there is a dispute related to approval of the Millennium Bill. The Public Staff states that the Commission should not give blanket approval to the Millennium Bill format on the basis of a single sample bill. Sprint states that it is not seeking blanket approval but only approval for an alternative format relative to the unregulated charges. The Commission agrees that it should not give blanket approval to the Millennium Bill but, as noted above, the use of symbols should be approved for nonregulated charges, provided that Sprint can demonstrate that they are being used clearly and consistently.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of September, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb092501.03

Commissioners Judy Hunt and Robert V. Owens, Jr. dissent.

DOCKET NO. P-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition for Rulemaking to Prohibit Slamming, Cramming and Related Abuses in the Marketing of Telecommunications Services	)))	ORDER PROMULGATING RULE R20

BY THE COMMISSION: On February 21, 2001, the Public Staff filed a Petition for Order Establishing Rulemaking Proceeding to prohibit slamming, cramming, and related abuses in the marketing of telecommunications. Slamming occurs when a customer's telephone service is transferred from one carrier to another without the customer's informed consent, while cramming occurs when a carrier bills a customer for services that the customer has not requested. Slamming and cramming are thus closely related. The Public Staff indicated that its Consumer Services Division had received 445 complaints about slamming in 2000, and over a hundred complaints regarding cramming in each of the past three years.

The Public Staff noted that, although the Commission has recognized that slamming in particular is an unfair and deceptive practice, it has never adopted a rule expressly prohibiting slamming, nor is there a statute that imposes such a prohibition. Last year, the Commission did elect to take primary responsibility in the enforcement of the Federal Communication Commission's (FCC's) slamming rules (FCC Rules 64.1100-.1195) in cases involving North Carolina consumers. However, because slamming is not explicitly banned, the Public Staff expressed doubts that the

Commission has the clear authority to impose fines on slammers under G.S. 62-310(a). The Public Staff argues that this authority would be highly desirable and would be a supplemental deterrent to violators, in addition to the sanctions authorized by the FCC. The great majority of states have prohibited slamming specifically and explicitly.

The Public Staff proposed adding a new chapter to the Commission Rules as Rule R19-1. In brief summary, the proposed rule provides as follows:

Subsection (a) prohibits slamming.

Subsection (b) lists the remedies available to a customer who has been transferred without express authorization.

Subsection (c) provides that upon the customer's request, an oral offer to provide telecommunications service must be sent to the customer in written form.

Subsection (d) prohibits cramming.

Subsection (e) provides that, whenever a telecommunications utility solicits a customer to transfer his service away from his existing carrier, the solicitation must include the name of the utility soliciting the change, the fact that the communication is in fact for the purpose of soliciting a change in the carrier, the fact that any change must be confirmed as required by law, and information as to any charge imposed for processing a change.

Subsection (f) contains the definition of terms.

By Order entered on March 6, 2001, the Commission established a rulemaking proceeding and solicited comments and reply comments from interested parties on the Public Staff's petition. Parties advocating amendments to the proposed Rule R19-1 were instructed to provide specific language to effectuate any such proposed changes.

Comments

Aspire Telecom, Inc. (Aspire) praised the rules as straightforward, and did not object to them, except as to the verbiage to be included in advertisements. While inclusion is not necessarily a problem in some formats, such as direct mail or telemarketing, smaller formats such as postcards, or television ads, could present difficulties. Postcards and television ads are the formats that Aspire uses.

ITC^DeltaCom Communications, Inc. (DeltaCom) stated that Rule R19-1(a) does not address situations involving the transfer of local customers. Problems can arise when a Local Service Request (LSR) is worked after the end user has already returned to the incumbent or another carrier. DeltaCom has no notice of this, and the customer may believe that he has been slammed. This situation has been identified by the National Number Portability Operations Team. Therefore, DeltaCom suggested that the following language be added to Rule R19-1(a):

(i) A telecommunications provider shall submit a Local Service Request to the customer's existing local provider prior to transferring or causing the transfer of the customer's local service.

DeltaCom recommends that the Commission require an LSR format that has been adopted by the Ordering Billing Forum and recommends that the guidelines established by the OBF for transferring customers' local services be adopted. By requiring the submission of an LSR, the prior authorized local carrier is notified of the change and can cancel any pending orders or any orders for additional service that have not been issued.

Carolina Telephone and Telegraph Company, Central Telephone Company and Sprint Communications, LP (collectively, Sprint) argued that the proposed Section R19-1(b)(2) should be deleted because the FCC has completed an in-depth fact-gathering proceeding to establish the appropriate penalties for slamming for both interstate and intrastate long distance services and it is Sprint's view that the Commission should not impose additional penalties beyond those of the FCC, since this would create a patchwork of state and federal rules. Sprint also criticized proposed Section R19-1(c) as being administratively burdensome and therefore should be deleted. Lastly, Section R19-1(d) should be amended to provide that those performing third-party billing services will not be held accountable for the fraudulent activities of other parties who are guilty of actually slamming or cramming end users. This problem comes into play for Sprint most often when Sprint is the underlying facilities-based carrier for a switchless reseller. Customers may believe that they have been slammed by Sprint when actually they have been slammed by the reseller. This confusion results form the fact that most switchless resellers do not have a Carrier Identification Code (CIC) of their own but use that of the underlying carrier. Sprint's proposed language more clearly reflects that the liability for slamming and cramming lies with the provider of the service, not the third-party billing agent. Sprint's proposal to amend proposed Rule R19-1(d) is as follows:

(d) No telecommunications provider shall provide any service to any customer for compensation or submit or authorize any billing to a billing agent unless and until the customer or the customer's representative has clearly, expressly, and affirmatively agreed to purchase the service. For purposes of this subsection, each day the provider continues to make the service available to the customer for compensation constitutes a separate violation, even if the customer does not actively make use of the service.

Qwest Communications Corporation (Qwest) offered the following comments: (1) R19-1(b)(2), which allows for payments to the slammed customers beyond those provided by the FCC, should be deleted as being unnecessary in light of the FCC's broad remedial provisions. (2) R19-1(b)(3), providing for penalties of up to $1000 per day per slam, should be revised to require the existence of egregious conduct before a penalty is assessed and to cap the penalty period at 120 days, which is consistent with FCC rules. (3) Rule R19-1(c), requiring carriers to provide upon the customer's request a written offer to provide communications services, is impractical in relation to Qwest's and other's marketing practices and should be revised to allow marketing representatives to refer a consumer to a website and/or a telephone number for a customer service representative, either of which could provide the terms of the offer in writing. (4) R19-1(d), which considers each day following a cram as a separate offense, exposes carriers to penalties in perpetuity, while the language that the customer must "clearly, expressly and affirmatively" agree to the purchase of the service is too broad and could be invoked to avoid payment by any customer failing to investigate applicable charges before making operator-assisted, collect, three-way, or other service-added calls. Also, the definition of cramming includes slamming, thereby exposing carriers to double penalties. Qwest suggests that this subsection should be rewritten to (a) cap the penalty period at 120 days, (b) exclude situations where a customer voluntarily and knowingly uses a service, even though the customer may not have made an express agreement to pay for the service, and (c) clarify that the regulation does not apply to slamming.

Attorney General strongly supported the adoption of rules to prohibit slamming and cramming and commended the Public Staff for proposing such rules. The Attorney General remarked that slamming is an unfair and deceptive trade practice that violates both Chapter 74 and Section 258(a) of the Telecommunications Act of 1996. The Consumer Protection Division of the North Carolina Department of Justice has received 219 slamming complaints. Essentially, the proposed rules mirror the FCC's rules and provide the Commission with a framework in which to administer those rules. While the FCC's rules represent a distinct improvement over prior FCC policies, those rules could be stronger in some respects. The Public Staff has correctly recognized that the refunds authorized by the FCC rules may not provide sufficient relief for some consumers or provide a sufficient deterrent to slamming carriers. The Attorney General favors additional authority under G.S. 62-310 to allow the imposition of penalties of up to $5,000 per offense. The Attorney General pledged to continue to fight against slamming and cramming even if the Commission adopts the Public Staff's proposed rules.

BellSouth Telecommunications, Inc., The Alliance of North Carolina Independent Telephone Companies, and ALLTEL Carolina, Inc. (ILEC Commenters), while applauding the Public Staff's efforts to combat slamming, cramming, and related abuses, expressed concerns about five subsections in need of clarification or amendment. First, Section R19-1(b)(2), giving the Commission the authority to require unauthorized providers to make additional payments to end-users in excess of those required by the FCC, should be stricken in its entirety. Although not preempted by the FCC, the Commission should appreciate that the FCC has thoroughly reviewed this issue and has set appropriate penalties. Second, the ILEC Commenters maintained that R19-1(c), concerning pre-sale product descriptions to customers upon request, should be stricken. It is unwieldy and unnecessary. Third, proposed R19-1(d) should be amended to prevent an innocent third-party biller from being held liable for another entity's slamming or cramming actions. The phrase "or bill any service to any customer" should be replaced with "or submit or authorize any billing." Also, language should be inserted to indicate that customer-initiated services such as per-use features are not covered. Finally, proposed R19-1(e)(2) should be amended to recognize that the purposes of sales solicitations are not always to change a customer's carrier but can be to sell some other product or service.

WorldCom stated that the Commission should follow the federal rules and remedies since it has opted-in to the FCC's slamming rules. This will ensure consistency. If the Commission elects not to adopt the FCC's slamming rules in their entirety, then the Commission should amend the proposed Rule R19 as follow: (1) Proposed Rule R19-1(b)(3) should be amended to penalize only "intentional or willful" slams; (2) the penalty proposed in Rule R19-1(b) should be limited to each incident of intentional unauthorized carrier change; (3) given the Public Staff's insistence that "every instance of slamming is accompanied by an instance of cramming," violation of proposed Rule R19-1(d) should not be deemed to constitute a separate violation; (4) proposed Rule R19-1(b)(2) concerning additional payments should be deleted; (5) proposed Rule R19-1(e)(3) should be clarified so that the carrier does not have to expressly refer to state and federal regulations in communications with a customer; (6) "Customer representative" as defined in proposed Rule R19-1(f)(2) should include anyone 18 years or older in the same household or an owner or officer of a company; and (7) the Commission should not invariably require suppression of telemarketing when a complaint has been filed.

AT&T Communications of the Southern States, Inc. (AT&T) made the following recommendations if the Commission chooses to adopt separate slamming rules: (1) Proposed Rule R19-1(a) should be amended so that it will be consistent with FCC rules regarding authorization and verification and so there will not be separate state and federal definitions. (2) Proposed Rule R19-1(b) should be made consistent with subsection (a) by referring to the FCC rules on authorization and verification. (3) With respect to proposed Rule R19-1(b)(1)(2) and (3), it is not necessary for the customer's authorized carrier to be made an actual party to the proceeding, but it should received notice of the proceeding consistent with FCC rules. Moreover, the refunds provision should be consistent with FCC rules, and penalties should be determined on a case-by-case basis. (4) With respect to proposed Rule R19-19(c), AT&T maintained that it is unreasonable to require that the rates, terms and conditions of the offer should be sent to customers in written form prior to customer acceptance. (5) With respect to Rule R19-1(d), regarding cramming, AT&T suggested that the Commission should decide the issue of penalties on a case-by-case basis. (6) Proposed Rule R19-1(e), regarding telemarketing, direct mail or solicitation forms, should be made consistent with FCC rules. (7) The definitional section in Rule R19-1(f) should be modified to adopt similar or the same terms and definitions as previously established by the FCC.

Time Warner Telecom of North Carolina LP (Time Warner) indicated that it did not have objections to the Public Staff's proposed rules per se but expressed concern about the requirement of "express authorization" in the context of local service. Time Warner urged the Commission to clarify that, with respect to local service, verification may be accomplished by having the customer sign a service contract. With respect to other services, verification must be obtained in compliance with the procedures set forth by the FCC. Time Warner's rationale was that the local customers signing service contracts do not need the same level of protection from slamming and cramming as other customers, and more documentation than a sales contract would be redundant paperwork.

Verizon South f/k/a GTE South Incorporated and Verizon Select Services, Inc. (Verizon), while agreeing that slamming and cramming are wrong, was not convinced that the Public Staff's proposed rules meet their objectives. Verizon objected particularly to what it characterized as a "two-tiered anti-slamming regime" where there were differences between the state and federal standards. If the Commission does decide to move ahead with state-specific rules, Verizon suggested what it called a streamlined version of the proposed rules. In particular, Verizon suggested that the subsection of proposed Rule R19-1(b)(3) be clarified so that only knowing and willful conduct would be penalized. Subsection (d) would be clarified so that the party submitting billing charges, rather than the billing party itself, would be responsible for obtaining customer authorization for charges. Subsection (f)(3) should be revised to recognize that a provider taking an order has no way of knowing whether an individual holding himself out as lawfully authorized to represent a customer does in fact have that authority. Finally, Verizon deleted subsection (e)(3), requiring disclosure in every solicitation that a customer's carrier may not be changed until it is affirmed in accordance with the FCC and Commission rules. With respect to cramming, Verizon noted that it has been active in policing cramming and that it has actively participated in the development of the telecommunications industry's "best practice guidelines" to address cramming and, pursuant to it, has adopted a "Bill Block" service to allow customer control over what charges appear on their bills. Verizon has also implemented "Truth in Billing Principles" released by the FCC in May 1999. The number of cramming complaints involving Verizon has been significantly reduced over the past 3 years. Verizon therefore was doubtful that new measures are necessary at this time. If the Commission does adopt such rules, subsection (d) should be revised to clarify that the rules are intended to reach only deliberate wrongdoing.

Reply Comments

WorldCom noted that Time Warner had advocated an amendment to proposed Rule R19-1(f) defining "express authorization." To the extent that Time Warner is proposing a method of verification which is in addition to those endorsed by the FCC, WorldCom does not object. WorldCom reiterated its opposition to the imposition of a $1,000 per day penalty in cases where there has been no harm and there is no "guilty" intent. Fines should only be on a per-incident basis. Similarly, WorldCom opposed making cramming a "separate violation," thus giving rise to multiple penalties for a single act. Under the proposed rule, there could be virtually unlimited liability since there could be several different "services" provided for "each day" the service is available to the end user, and each service would constitute a separate violation. Therefore, WorldCom has recommended that the last sentence of the proposed Rule R19-1(d) should be deleted.

Public Staff examined the comments of the parties in detail, finding merit in some of the suggestions and rejecting others. The Public Staff provided a revised proposed Rule R19. In general, the Public Staff noted that slamming violations are still occurring far too frequently. Objections that the Public Staff's proposed rule would create "a two-tiered anti-slamming regime" miss the point. A carrier electing to do business in numerous states cannot reasonably expect identical requirements to be imposed in each state. The Public Staff's proposed rule is not inconsistent with the FCC regulations. Indeed, in order to avoid any inconsistency, the Public Staff has made subsections (b)(2) and (b)(3) applicable only to intrastate slamming. In the cases of interstate slamming, the remedies available under the proposed rule are exactly the same as those allowed by the federal regulations. The FCC has pointedly not prohibited the states from adopting rules on slamming. The Public Staff made the following specific observations regarding the comments as to the various subsections:

Subsection (a). The Public staff rejected the suggestion that the proposed rule should delete the requirement that the customer give "express" authorization. The proposed definition in (f)(1) includes a reference to the FCC regulations. It will not be difficult for a submitting provider to obtain a customer's express authorization by using verification methods provided for in the FCC regulations. The concern expressed by DeltaCom with respect to submission of the LSR to a customer's existing local service provider, while it may have some merit, is better addressed at this time by the industry, rather than being the subject of a Commission rule.

Subsection (b). Any change here is unnecessary. All decisions of the Commission must already comply with due process, and citations to FCC slamming regulations already appear in the proposed rule.

Subsection (b)(1). Since, under FCC regulations, the authorized carrier may be required to return to the customer a portion of the refund it receives from the unauthorized carrier, the Public Staff believes that it will sometimes be appropriate to make the authorized carrier a party to the proceeding. References to the Commission's opt-in status are unnecessary.

Subsection (b)(2). The Public Staff believes that the additional remedies available in intrastate cases under this subsection can be administered without difficulty and are not likely to result in confusion. However, the Public Staff agrees that the language needs to be revised to make clear the exact extent of the Commission's jurisdiction. In any event, the decision whether to allow remedies beyond those provided for in the FCC regulations is permissive rather than mandatory. The Public Staff does not believe that the refunds allowed under this subsection will promote fraudulent claims by consumers.

Subsection (b)(3). The Public Staff disagrees with the proposals that a penalty should only be imposed for intentional violations. Proving that a violation was committed intentionally rather than by mistake is difficult and would generally require extensive discovery, which the customer should not have to bear. In any event, the company is entitled to offer evidence that the violations were unintentional. The Public Staff also disagreed with the contention that the penalty for slamming violations should be limited to 1,000 per violation rather than $1,000 per day, or that the penalty period should be limited to 120 days. Such a penalty would be too small to be a deterrent. The Public Staff also pointed out that G.S. 62-310(a) has a per-day standard.

Subsection (c). The Public Staff argued that this subsection is a very important provision of the proposed rule and should not be deleted, especially in light of the numerous add-on charges that are currently being added to bills. Telecommunications service is a very complex product, with many terms and conditions which can change quickly. The provision does not require that an offer of telecommunications service be sent in written form to every customer, but only upon request.

Subsection (d). The Public Staff agreed that, when a telecommunications provider directs its billing agent to bill a customer for a service and the billing agent does so, the billing agent should be the one viewed as having committed the cramming violation. However, the Public Staff disagreed that the subsection should not apply to customer-initiated services, such as per-use features or operator-assisted calls. To do so would in essence exclude those services from the rule against cramming. The customer-initiated services require an affirmative action on the part of customer in order for the service to be properly billed. Once that action has been taken, there can be no cramming violation. The Public Staff rejected the proposals to cap penalties, along with the suggestions that the cramming must be intentional. The Public Staff also rejected the view that "actions expressing a knowing use of the service" should necessarily allow avoidance of a cramming violation. This would tend to countenance an abusive form of marketing. Lastly, the Public Staff argued that both the unauthorized transfer and the billing of an unrequested service should be considered violation of the Commission's rules.

Subsection (e). The Public Staff does not believe that the disclosure requirements are onerous or burdensome, especially in light of the proposed Public Staff revisions.

Subsection (e)(2). The Public Staff agreed that the language of this subdivision should be revised because, as was pointed out, some situations, such as the marketing of the Area Plus Service, do not have as their primary purpose to persuade the customer to change providers, but the receiving of intraLATA toll service is necessary to receive the full benefits of Area Plus.

.Subsection (e)(3). The Public Staff does not believe that this subsection should be deleted. If a solicitation informs the customer that a change must comply with the applicable rules, this tends to increase the likelihood that it will in fact comply. However, the Public Staff agrees that there is no need to include a reference to a particular regulatory provision.

Subsection (e)(4). The Public Staff does not object to a revision that requires the carrier making the solicitation to notify the customer that a charge may be imposed, rather than providing a description of the charge.

Subsection (f)(1). The Public Staff, for the reasons stated above, does not believe that the requirement for express authorization should be deleted or the definition changed. The Public Staff also opposed the proposal that a change in local service provider should be verified through the customer's execution of a service contract. The verification methods allowed by the FCC have been carefully considered and are adequate. A carrier should not be allowed to avoid the FCC requirements by use of a service contract.

Subsections (f)(2) and (f)(3). The Public Staff opposed proposals that would treat a person as a customer representative even though he is clearly not the customer's representative in the ordinary sense of the term. A utility's decision to conduct business over the telephone is a business decision carrying both risks and benefits. The Public Staff also noted that it had intentionally departed from the FCC's definition of "subscriber" in its definition of "customer" in order to narrow the definition to "the party in whose name the telecommunications service is provided."

<u>Sprint</u> expressed concern that customers will be given an incentive not to report the alleged unauthorized switch on a timely basis under the proposed rules. The FCC rules are preferable. With respect to cramming, Sprint noted that the proposed rule is vague as to what constitutes "clearly, expressly, and affirmatively" agreeing to the purchase of a service with respect to services, such as operator-assisted, collect, or dial-around access which are generally available in the marketplace and totally controlled by the customer. The essence of such services is the ability of consumers to receive and place a call and receive billing without giving prior authorization to the carrier. If carriers are required to obtain the consumer's authorization prior to making the services available, carriers will be forced to block these services from their networks and consumers will thereby lose the ability to use them conveniently. The Commission should instead rely on safeguards already established to combat cramming, such as the self-imposed monitoring system in the form of the Best Practices Guidelines which are sanctioned by the FCC.

<u>Verizon</u> reemphasized its view that the Commission should place primary reliance on the FCC slamming rules that the Commission has committed to enforcing. Verizon argued that there has been no demonstration that the proposed rules are needed, but rather the Commission should focus on chronic offenders. Adopting the federal rules will ensure consistency in implementation and will benefit consumers. Certainly, there is no need to adopt a state rule requiring payments over and

above those required by the federal rules, nor is a rulemaking the appropriate forum to address carrier-to-carrier operational matters.

Attorney General reiterated the need for slamming and cramming rules and argued that the Public Staff's proposed rules are consistent with the FCC's. The Attorney General reviewed the proposed amendments made by the companies. The Attorney General found most of the proposed changes to be without merit but did acknowledge that in most instances primary liability for cramming lies with the cramming entity and not with the LEC that provides nothing more than the billing service. Absent knowledge, notice, or some other factor, simply providing a billing service does not equate to cramming. On the general question of intentionality, the Attorney General noted that the FCC's slamming rules expressly provide that carriers are responsible for all unauthorized changes in service whether intentional or not. The Attorney General strongly supported the Public Staff's proposed rules to prohibit slamming or cramming. If anything, the applicable penalties should be strengthened in order to deter these practices.

ILEC Commenters replied to the comments of the other parties. They opposed DeltaCom's suggestion that a telecommunications provider submit an LSR to the customer's existing local provider prior to transfer. They also opposed Time Warner's suggestion that local service contracts not be made an additional vehicle for verification. They reiterated their view that the burden for violations should be on the crammer and not on the billing agent.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the revised Public Staff proposed Rule R19 as set out in its May 16, 2001 Reply Comments be adopted for the reasons as generally set out by the Public Staff. The Commission further concludes that proposed Rule R19-1(d) should also be amended to incorporate the additional language regarding per-use and dial-around charges as discussed and set out below.[1]

The Commission believes that the Public Staff and the Attorney General should be commended for their efforts against slamming and cramming. While progress has been made both nationally and at the state level, slamming and cramming remain serious problems in the industry and irksome irritants to consumers. The Public Staff's proposed rules represent a balanced approach that seeks to make the customer whole and toughens penalties, but at the same time takes into consideration the legitimate interests of the telecommunications providers. Telecommunications are a complicated product, and it is not unreasonable to expect those who would market such services over the telephone to assume greater burdens and risks concerning customer understanding of what the customer is getting into. An ethical provider which polices itself and its marketing agents should have no serious problem with these rules. Those who are lax, or, worse, intent on fraud, should be wary.

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[1]Because a Rule R19 has already been enacted in connection with Docket No. E-100, Sub 89, this rule should be denominated Rule R20.

The only concern that the Commission has with the revised proposed rules centers around the proposed Rule R19-1(d) with respect to so-called per-use calling. This is plainly a different situation from solicitation because the service pre-exists on the network and generally there is no person-to-person interaction. The Public Staff has rightly argued that per-use services should not be exempted from being the subject of cramming violations. Fictitious per-use charges are possible, and an exemption from the cramming prohibition might provide an incentive to the unscrupulous. The Public Staff also correctly observed that per-use services require an affirmative action by the customer for proper billing and, if the customer has input the numbers to access, there is no question of a slamming violation. However, a problematical situation might arise if an employee of a customer or a member of the customer's household or a guest accesses a per-use service without the customer's knowledge or consent. As the Public Staff's proposed rule is presently written, this would seem to give rise to a cramming violation by a provider. This is contrary to the general understanding that the customer is responsible for the use of his phone by employees or by household members and guests. At the same time, the Commission has recognized the problems inherent in consent and control issues in households and has established and encouraged in certain circumstances the institution of forgiveness policies on the part of providers. Obviously, this issue has a number of facets.

The Commission therefore concludes that the first sentence of the proposed Rule R19-1(d) should be amended to read as follows:

> (d) No telecommunications provider shall provide any service to any customer for compensation or submit or authorize any billing, unless and until the customer or the customer's representative has clearly, expressly, and affirmatively agreed to purchase the service; provided, however, with respect to dial-around charges or per-use charges associated with vertical feature offerings of local providers and subject to forgiveness policies relating to the billing of charges, use of such services by an employee of the customer or by a member or guest of the customer's household shall be deemed to have been made under the authority of the customer.

While it is difficult to set out in a rule a means to address every conceivable circumstance, the Commission believes that this proviso will address a large class of cases that might otherwise give rise to an unjust imputation of cramming. As to other instances in which an unjust imputation of cramming may arise, the Commission will in individual cases consider the totality of the circumstances and the reasonable responsibilities of the parties concerned.

IT IS THEREFORE ORDERED that Rule R20-1 et seq be promulgated as set out in Appendix A. Such rules shall become effective on August 1, 2001.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

d071101.01

APPENDIX A

Rule R20-1. Slamming, cramming and related abuses in the marketing of telecommunications services.

(a) No telecommunications provider shall submit, or cause to be submitted, a change order for preferred intraLATA interexchange carrier, interLATA interexchange carrier or local exchange carrier to any telecommunications company unless and until the submitting provider has obtained express authorization from the customer or the customer's representative for each change.

(b) If the Commission determines that a telecommunications provider has submitted, or caused to be submitted, a change order and cannot demonstrate that it has complied with subsection (a), the Commission:

(1) Shall make available to the customer the remedies authorized by the regulations of the Federal Communications Commission, with respect to both interstate and intrastate service, and for this purpose the customer's authorized carrier may be made a party to the proceeding;

(2) With respect to intrastate service, may require the unauthorized provider to make any additional payments, beyond those required by the regulations of the Federal Communications Commission, that are necessary to ensure that the customer is fully reimbursed for all payments made to the unauthorized provider and any other charges imposed by a telecommunications utility because of the unauthorized change in carrier; and

(3) With respect to intrastate service, may require the unauthorized provider to pay a penalty in accordance with G.S. 62-310 for each day the provider continues to make an unauthorized service available to the customer, even if the customer does not actively make use of the service.

(c) Upon request of the customer or the customer's representative, any offer to provide telecommunications services shall be sent to the customer in written form describing the rates, terms and conditions of service. Such request shall not be deemed to be acceptance of an offer to provide telecommunications services.

(d) No telecommunications provider shall provide any service to any customer for compensation, or submit or authorize any billing, unless and until the customer or the customer's representative has clearly, expressly and affirmatively agreed to purchase the service; provided, however, with respect to dial-around charges or per-use charges associated with vertical feature offerings of local providers and subject to forgiveness policies relating to the billing of charges, use of such services by an employee of the customer or by a member or guest of the customer's household shall be deemed to have been made under the authority of the customer. For purposes of this subsection, each day the provider continues to make the service available to the customer for compensation constitutes a separate violation, even if the customer does not actively make use of the service.

(e) Any telecommunications provider's telemarketing, direct mail or other forms of solicitation to change a customer's preferred local exchange carrier, intraLATA interexchange carrier, or interLATA interexchange carrier shall include the following disclosures:

(1) Identification of the telecommunications provider soliciting the change in the preferred local exchange, intraLATA long distance or interLATA long distance carrier;

(2) That the purpose of the call or direct mail or other solicitation is to solicit a change of the customer's preferred carrier of local exchange, intraLATA long distance or interLATA long distance service (or, if applicable, that the outcome of the call or direct mail or other solicitation will be a change of the customer's preferred carrier of local exchange, intraLATA long distance or interLATA long distance service);

(3) That the customer's preferred local exchange, intraLATA long distance or interLATA long distance carrier may not be changed unless and until the requested change is confirmed in accordance with this section and the regulations of the Federal Communications Commission; however, no specific citation to this rule or the regulations of the Federal Communications Commission is required; and

(4) Notice to the customer that a charge may be imposed upon the customer for processing the change in the customer's preferred local exchange carrier, intraLATA interexchange carrier or interLATA interexchange carrier.

(f) As used in this section:

(1) "Express authorization" means an express, affirmative act by the customer or the customer's representative clearly agreeing to the change in preferred intraLATA interexchange carrier, interLATA interexchange carrier or local exchange carrier, in a manner consistent with this section and the regulations of the Federal Communications Commission.

(2) "Customer" means the party in whose name the telecommunications service is provided.

(3) "Customer's representative" means any adult person authorized by the customer to change telecommunications services, or contractually or otherwise lawfully authorized to represent the customer.

(4) "Telecommunications provider" means any public utility that provides telecommunications service.

DOCKET NO. P-100, SUB 148

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Motions for Clarification or Reconsideration on Slamming and Cramming Rules	)))	ORDER RULING ON MOTIONS FOR RECONSIDERATION AND CLARIFICATION

BY THE COMMISSION: On August 13, 2001, WorldCom, Inc. (WorldCom) submitted a Motion for Clarification or Reconsideration of the July 12, 2001 Order Promulgating Rule R20. WorldCom addressed two points.

First, WorldCom asked that the Commission clarify that subsection (d) of Rule R20-1 is not intended to apply to "slamming," or, alternatively, that a "slamming" violation is not also a "cramming" violation. WorldCom maintained that, contrary to the Public Staff's assertion, not every instance of "slamming" is also "cramming." It is unjust that a single act could result in the imposition of penalties for both slamming and cramming. The Commission should adopt the language proposed by Qwest in the comments by stating: "This subsection does not apply to changes in telecommunications providers, which is governed by other subsections herein." Or the Commission should at least clarify its intent to that effect.

Second, WorldCom was concerned about the definition of "customer's representative." Currently, the "Customer's representative" is defined as "any adult person authorized to change telecommunications services, or contractually or unlawfully authorized to represent the customer." WorldCom believes that the definition should be amended to include anyone eighteen years or older within the same household, or an owner or officer of a company." This is in accord with Rule 25-4.118(1) adopted by the Florida Public Service Commission. WorldCom's concern was that the rule's current definition is too narrow and would lead to complications and difficulties, especially as to questions of agency. WorldCom also noted that customers frequently will initiate contact with a carrier; carriers should not be penalized for wrongful representation of such customers. WorldCom also represented that, after consultation with the Public Staff, it did not believe that the Public Staff maintains that the definition is intended to be limited to the person billed by the carrier presently serving the end-user. WorldCom also noted that the Commission created an exception for dial-around and certain per-use charges. While WorldCom supports these exceptions, they also illustrate that there is a problem with this subsection.

BellSouth Motion

On August 31, 2001, BellSouth Telecommunications, Inc. (BellSouth) filed a Motion for Clarification. BellSouth noted that the text of the Order contained what it characterized as a "small, but significant, typographical error." On page 8, subsection (d), BellSouth believed that the first sentence should read as follows: "The Public Staff agreed that, when a telecommunications provider directs its billing agent to bill a customer for a service and the billing agent does so, the billing agent should not be the one viewed as having committed the cramming violation." BellSouth believed that the insertion of the word "not" more accurately reflects the Public Staff's position in this case.

Responses to WorldCom Motion

Attorney General characterized WorldCom's Motion as less one for clarification and more one for reconsideration while reploughing the same ground in the process. First, WorldCom revived its argument that an act of cramming should not also give rise to an act of slamming, resulting in more than one penalty. The Attorney General noted that the Commission had indicated its preference for strong penalties to discourage harmful activities. He also noted that the imposition of penalties is discretionary. Second, WorldCom asked the Commission to change the definition of "customer's representative" so that any person 18 years of age or older within the same household could authorize changes, regardless of whether that person was in fact so authorized. The Attorney General observed that the Commission had already rejected this idea, noting that the carrier should bear the risk when it chooses to telemarket. This is consistent with FCC rules which provide for a strict liability standard on unauthorized changes. For example, in an Order of Forfeiture adopted by the FCC on April 12, 2001, the carrier in question argued that it did not commit slamming when it processed a switch based on a forged letter of authorization (LOA) because the carrier did not know or have reason to know that the signature was not authentic. The FCC rejected this argument noting that the slamming rules provide for liability whether the slam was intentional or not.

In a reply to the Attorney General's response, WorldCom on September 13, 2001, observed that the Attorney General had not proposed any standard by which the Commission may decide whether to impose two penalties for a slamming violation and argued that, in fact, none is possible. WorldCom also denied that it was attempting to "end-run" the FCC's rules by proposing the same standard as that promulgated by the Florida Public Service Commission. The Florida Commission is scarcely "loose" when it comes to consumer-related regulation.

Sprint Comments

On September 21, 2001, Carolina Telephone and Telegraph Company, Central Telephone Company, and Sprint Communications Company LP (collectively, Sprint) filed Further Comments regarding rulemaking in support of WorldCom's Motion and in response to the Attorney General's comments. Specifically, Sprint did not believe that multiple penalties should be permitted; that the party authorized to make changes in services should not be limited solely to the party in whose name the service is provided but should be broadened to include any representative of the customer with authority to make such changes, such as a spouse; and that carriers should not be held liable in the form of penalties when they have relied on apparent authority. In no event should the Commission impose penalties where unauthorized charges are the result of unintentional or inadvertent failures on the part of the provider.

Order Seeking Comments

On September 26, 2001, the Commission issued an Order Seeking Comments in order to regularize and finalize procedure in this docket.

AT&T Comments

AT&T Communications of the Southern States, Inc. (AT&T) stated its support of WorldCom's Motion and the comments filed by Sprint in support of the WorldCom Motion and continued to express its concern with the current version of Rule R20-1 for the reasons set out in its original comments. A single act should only give rise to a single penalty, and a provider should not be penalized if its acts in good faith and upon a party's assertion of authorization.

Public Staff Response to Motions and Comments

The Public Staff stated that it agreed with BellSouth's Motion for Clarification. It does not require that the rule be changed because the omission of the word "not" appeared in the text, not the rule.

The Public Staff opposed WorldCom's Motion for Clarification and Reconsideration and disagrees with the comments filed by Sprint. With respect to penalties for cramming that occur in connection with slamming, the Public Staff observed that the Commission has already rejected a revision that would allow only a single penalty. Two violations have occurred in such instances, and it is not unfair to penalize a carrier $2,000 per day if it slams and crams unrequested service onto the customer's bill. It is not uncommon in both criminal and civil law for a course of conduct to violate two different rules or statutes and for the offender to be penalized for both. If such a revision were adopted, it would treat cramming occurring in connection with slamming more favorably than cramming alone.

The Public Staff also opposed WorldCom's and Sprint's attempt to more narrowly define "customer" and "customer's representative." Such a change would lead to unjust results and is designed to protect the telemarketers at the expense of the interests of the consumer. The Public Staff also found no relevance to the matters at hand of Sprint's discussion of the legal doctrine of apparent authority. The Public Staff noted that the doctrine is applicable almost exclusively to commercial transactions and does not apply to the purchase of residential phone service. A person who makes arrangements for residential phone service does not "by words or conduct represent or permit it to be represented" that the other people in his home are agents.

The Public Staff noted that WorldCom has represented that the Public Staff had acceded to the viewpoint that, if both the husband and wife are listed in the white pages of the telephone directory, both spouses would be considered customers. This was pursuant to a phone conversation between a Public Staff attorney and a WorldCom attorney. The Public Staff stated that it has not agreed to interpret the term "customer" any more broadly than this, and it further observed that, just because a telephone is listed in the directory under two names does not necessarily indicated that the service is provided in both persons' names.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that WorldCom's Motion for Clarification or Reconsideration should be denied but that BellSouth's Motion for Clarification should be allowed.

WorldCom argued that a single act should not give rise to a penalty for slamming and for cramming and that the definition of "customers representative" should be broadened. Both these issues were thoroughly explored in the comments leading up to the July 12, 2001, Order Promulgating Rule R20, and WorldCom and its allies have adduced no significant new arguments in their favor on these issues, while the arguments made by the Public Staff and the Attorney General remain cogent and convincing. Moreover, it should be recalled that the Commission modified Rule R20-1(d) to broaden the circumstances under which carrier liability for cramming would not be found--specifically, the cases of dial-around charges or per-use charges associated with vertical features incurred by an employee of the customer or by a member or guest of the customer's household. The Commission concluded its July 12, 2001, Order by stating: "As to other instances in which an unjust imputation of cramming may arise, the Commission will in individual cases consider the totality of the circumstances and the reasonable responsibilities of the parties concerned."

Finally, the Commission concurs with BellSouth's Motion for Clarification regarding the text of the July 12, 2001, Order relating to the first sentence of subsection (d) on Page 8.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb110501.04

DOCKET NO. P-100, SUB 149

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Revisions to Implement North Carolina	)	ORDER REQUIRING FILINGS
Session Law 2001-430 (House Bill 571)	)	BY ILECS

BY THE CHAIR: On October 11, 2001, the Public Staff filed a Motion to Require Tariff Revisions–specifically, to enter an Order requiring all incumbent local exchange telephone companies (ILECs) in North Carolina to file revised tariffs containing appropriate reductions to reflect the elimination of the 3.22% franchise tax on gross receipts formerly imposed on telephone companies by G.S. 105-120 (the "gross receipts tax") and the application of the franchise tax on capital stock, surplus, undivided profits and property imposed by G.S. 105-122 (the "standard franchise tax"). In support of this motion, the Public Staff stated as follows:

1. On October 6, 2001, Governor Michael F. Easley signed North Carolina Session Law 2001-430 (Chapter 430 or House Bill 571), which extensively revises the statutes governing the taxation of telecommunications services in North Carolina. Section 20 of Chapter 430 states that it "becomes effective January 1, 2002, and applies to taxable services reflected on bills dated on or after January 1, 2002."

2. Section 12 of Chapter 430 repeals G.S. 105-120 and thus abolishes the gross receipts tax.

3. Prior to the enactment of Chapter 430, telephone utilities were not liable for payment of the standard franchise tax. Under G.S. 105-114(a)(2), they were in effect allowed to credit their gross receipts tax payments against their liability for the standard franchise tax, and the gross receipts tax uniformly exceeded the standard franchise tax. With the elimination of the gross receipts tax, the companies are now subject to the standard franchise tax. Section 18 of Chapter 430 requires that the Commission "lower the rate set for local telecommunications service to reflect the repeal of G.S. 105-120 and the resulting liability of local telecommunications companies for the tax imposed under G.S. 105-122."

4. Competing local providers (CLPs) should be exempted from the mandatory rate reductions which the Commission must impose under section 18 of Chapter 430. Although CLPs are affected by the changes in the tax law, their rates are not regulated by the Commission or filed with the Commission. These carriers may raise or lower their rates at will, after any required notice and subject to any contracts between them and their end users.

5. The most appropriate method of implementing Section 18 of Chapter 430 is for the Commission to require each ILEC to propose reductions in local rates equal to the difference between its former liability for the gross receipts tax and its new liability for the standard franchise tax.

6. In order to ensure that all ILECs follow a uniform procedure in calculating their former liability for the gross receipts tax and their new liability for the standard franchise tax, the Commission should provide specific directions for making the calculation. The Public Staff's recommendations are as follows:

a. The former gross receipts tax liability should be taken from reports filed with the Department of Revenue for the year 2000.

b. The new franchise tax liability should be calculated in accordance with G.S. 105-122, as shown on North Carolina Department of Revenue Form CD-405. Form CD-405 and instructions may be found at the Department of Revenue's website, www.dor.state.nc.us. The liability should be calculated using 1999 data (i.e., it should be calculated as if the company were filing its 1999 Form CD-405, which normally would be due in 2000). The net revenue reduction required is equal to the former gross receipts tax liability minus the new standard franchise tax liability.

c. The recurring rate reductions should be based on units in service as of December 31, 2000. Any nonrecurring or usage-sensitive rate reductions should be based on units over a recent three-month period.

d. All reductions should be made in rates to which the gross receipts tax formerly applied. This would exclude rates for all long distance services, all access services provided to interexchange carriers, and all interexchange private line services. The reductions should provide a benefit to the majority of local ratepayers. The rate reductions should produce net revenue reductions equal to the amount calculated pursuant to subparagraph (b) above.

7. To provide an opportunity for interested parties to comment on the calculations and the rate proposals and to shorten the needed comment period, the Public Staff recommended that all of the State's 16 ILECs should be directed to file detailed workpapers on the calculation of the net revenue reduction required pursuant to subparagraphs 6(a) and 6(b) above), a detailed summary of their rate reduction proposals, and detailed workpapers on their rate and revenue reductions, by November 9, 2001. The rate and revenue reduction workpapers should be filed in accordance with Item No. 30 of NCUC Form P-1 referenced in Commission Rule R1-17(a)(12). Comments on the ILECs' filings should be filed no later than November 21, 2001, and reply comments should be filed by November 29, 2001. A Commission Order should be issued no later than December 15, 2001 in order to provide for rate changes in bills issued on or after January 1, 2002. Any failure to implement the Commission-approved rate changes by January 1 would require credits retroactive to January 1.

Accordingly, the Public Staff recommended:

1. That the Commission order the ILECs to make the calculations described in paragraph 6 above and submit the documentation outlined in paragraph 7 above; and

2. That the Commission adopt the filing schedule set forth in paragraph 7 above.

WHEREUPON, the Chair reaches the following

CONCLUSIONS

After careful consideration, the Chair concludes as follows:

1. That the CLPs should be exempted from the mandatory reductions which the Commission must impose under Section 18 of Chapter 430 for the reasons set forth by the Public Staff.

2. That, in order to expedite matters, the Public Staff shall review the filings required below and shall present its recommendations at the Regular Commission Staff Conference to be held on Monday, December 3, 2001. Interested parties shall have an opportunity to comment on the Public Staff's recommendations at the Regular Commission Staff Conference.

3. That the ILECs should be directed to file detailed workpapers on the calculation of the net revenue reduction, a detailed summary of their rates reduction proposals, and detailed workpapers on their rate and revenue reductions by no later than Friday, November 9, 2001. The rate and revenue reduction workpapers should be filed in accordance with Item No. 30 of the NCUC Form P-1 referenced in Commission Rule R1-17(a)(12). Calculations and proposed rate reductions shall be in accordance with Paragraph 5 and Paragraph 6.a. - d. above.

4. That, in recognition of the possibility that Section 18 of North Carolina Session Law 2001-430 may be amended, parties are put on notice that the schedule set forth above may need to be modified concerning the nature and extent of rate and revenue reductions. However, parties are to adhere to the above schedule and criteria unless otherwise advised. The Commission wishes to provide for rate changes in bills issued on or after January 1, 2002, and any failure to implement the Commission-approved rate changes by January 1, 2002, will require credits retroactive to January 1, 2002.

5. That all ILECs shall be made parties to this docket.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb102301.01

DOCKET NO. P-100, SUB 149

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Tariff Revisions to Implement North Carolina Session	)	ORDER RULING ON
Law 2001-430 (House Bill 571)	)	IMPLEMENTATION
	)	PROPOSALS

BY THE COMMISSION: On October 24, 2001, the Commission required the State's incumbent local exchange companies (LECs) to file proposals to reduce rates to offset the net tax expense reductions expected as a result of North Carolina Session Law 2001-430 (House Bill 571), and further required the Public Staff to review the companies' filings and present its recommendations at the Commission's December 3 Staff Conference.

The Public Staff presented its recommendations at the Regular Commission Staff Conference on December 10, 2001. Some of the companies have revised their proposals since they were initially filed, and the Public Staff described the revisions that have been made. Some companies have filed proposals with more than one option, and in these instances the Public Staff has explained its reasons for recommending one option rather than another.

According, to the Public Staff, Barnardsville Telephone Company (Barnardsville), BellSouth Telecommunications, Inc. (BellSouth), Citizens Telephone Company (Citizens), Concord Telephone Company (Concord), Ellerbe Telephone Company (Ellerbe), North State Telephone Company (North State), Pineville Telephone Company (Pineville), Randolph Telephone Company (Randolph), Saluda Mountain Telephone Company (Saluda Mountain), Service Telephone Company (Service), and Verizon South, Inc. (Verizon) have submitted proposals that comply with the requirements of the statute and the Commission's order. Carolina Telephone and Telegraph Company and Central Telephone Company (collectively, Carolina) have not calculated the amount of their required rate reductions correctly, and the Public Staff has recalculated the required amount and proposed additional rate changes that will bring their reductions to the required level. LEXCOM Telephone Company (LEXCOM) and MEBTEL, Inc. (MEBTEL) have submitted rate reduction proposals which the Public Staff does not believe to be appropriate, and the Public Staff recommended that they be modified. The Public Staff also believes that the proposal filed by ALLTEL Carolina, Inc. (ALLTEL) is not acceptable and recommended that the Commission direct ALLTEL to file a new proposal.

As noted above, in the Commission's order of October 24, 2001, in Docket No. P-100, Sub 149. The Commission directed the State's incumbent local exchange companies to file proposed rate reductions implementing North Carolina Session Law 2001-430 (House Bill 571). The Commission further directed the Public Staff to review the filings and present its recommendations at the Regular Commission Staff Conference to be held on Monday, December 3, 2001. On November 30 the Commission ordered that the Public Staff's presentation of its recommendations be delayed until the December 10 staff conference.

As originally written, Section 18 of House Bill 571 provided: "Pursuant to G.S. 62-31 and G.S. 62-32, the Utilities Commission must lower the rate set for local telecommunications service to reflect the repeal of G.S. 105-120 and the resulting liability of local telecommunications companies for the tax imposed under G.S. 165-122."

Later this provision was revised by striking the words "rate set for local telecommunications services" and substituting the words "rates set for telecommunications services." This has the effect of increasing the discretion of the Commission to decide the services upon which adjustments may be required, including access charges.

Most of the companies have responded to the Commission's order by proposing major changes in their expanded local calling plans. Several companies have proposed to eliminate the per minute rates for calling from their exchanges to all points within the first one or two ELCA bands, 0 to 10 and 11 to 16 miles. As a result, there is some interplay between the proposals of different companies. A few of the companies' proposals have two options, depending upon whether or not Section 18 of the law is ultimately amended to allow reductions in rates other than those for local telecommunications service. House Bill 338 would amend the statute in this manner; it has passed the House and Senate but currently has not been signed by the Governor.

<u>Amount of the Required Reductions</u>

For all companies except Carolina and Central, the Public Staff has been able to confirm that the amount of the companies' proposed reductions is correct. The Public Staff's review indicated that Carolina and Central did not perform their computations in the manner ordered by the Commission and consequently understated their required reductions. However, in order to avoid litigation over this issue, the Public Staff and Carolina and Central have entered into a compromise agreement that specifies the proper revenue reductions for these companies.

<u>Access Reductions</u>

Several of the LECs have proposed reductions in access charges as the total reduction or as a very large portion of their proposed reductions. These proposals are not consistent with Session Law 2001-430 as currently worded and can be adopted only if House Bill 338 is signed by the Governor and becomes law. The Public Staff believes, however, that even if the statute is amended, the majority of the proposed reductions should be in rates that directly benefit end users. The Public Staff recognized that some of the companies proposing large access charge reductions have access rates that are among the highest in the State; however, the Public Staff is concerned that many long distance companies have been reluctant to flow through previous access charge reductions in an appropriate manner, and we expect that there will be difficulties in flowing through any access charge reductions adopted in this case. If some of the IXCs are able to avoid all or a portion of the flow-through, the end users will never see the offset in rates as the Legislature intended. Another reason for preferring reductions in rates other than access charges is that even if the access charge reductions are flowed through by the IXCs, they will appear to the end user to be reductions in the IXCs' rates rather than in the LECs' rates, possibly prompting the end user to question the validity of the LECs' reductions. Therefore, if Section 18 is changed to allow access reductions, the Public Staff can agree to proposals that involve access reductions amounting to 40% or less of the total required reductions, but we oppose proposals that would reduce only access charges.

Effective Date and Customer Notice

In accordance with the Commission's order of October 24, 2001 in this docket, the Public Staff believes that the LECs' rate reductions should take effect on January 1, 2002. Most of the companies are proposing reductions in EAS or ELCA charges, and customers will not be able to obtain the full benefit of these reductions unless they receive notice of them in advance. Therefore, the Public Staff recommends that the Commission direct each LEC to notify its customers of its rate reductions by an insert in the bill received by the customer in December 2001 or January 2002, or by a direct mailing sent to the customer on or before January 15, 2002.

ALLTEL

ALLTEL Carolina originally filed two proposals. The primary proposal, which was to be implemented if Section 18 was not revised, provided (among other things) for the establishment of one-way EAS from ALLTEL's Granite Quarry exchange to the Concord Telephone exchanges of China Grove and Concord and from ALLTEL's Denton exchange to Randolph TMC's Badin Lake exchange. ALLTEL's alternate proposal, to be implemented if the word "local" were removed from Section 18, involved only access reductions.

In a December 5, 2001, filing, ALLTEL modified each of its proposals, but the Public Staff is still unable to agree to either proposal. ALLTEL's primary proposal, as revised, provides for (1) reducing rates for all expanded local calls, and (2) establishing one-way EAS from the Granite Quarry exchange to China Grove and Concord, but not from Denton to Badin Lake. The Public Staff objects to this proposal for two reasons. First, the Public Staff has not received workpapers from ALLTEL showing that the rate reductions are sufficient to bring about the required revenue reduction. Second, the Public Staff believes that one-way EAS should be implemented from Denton to Badin Lake, as well as from Granite Quarry to China Grove and Concord. The Public Staff has not been able to reach agreement with ALLTEL, and accordingly, if House Bill 338 has not become law at the time of issuance of the Commission's order, we recommend that the Commission direct ALLTEL to submit a new proposal that meets the following guidelines: (1) One-way EAS should be established from Granite Quarry to China Grove and Concord and also from Denton to Badin Lake. (2) The rate reductions for expanded local calls proposed by ALLTEL should be adjusted as necessary to provide the remainder of the required revenue reduction, and ALLTEL should file workpapers showing the amount of the revenue reduction resulting from these rate changes.

Under ALLTEL's alternative proposal, which the Company prefers if House Bill 338 becomes law, 80% of the required revenue reduction will come from decreases in access charges. The remaining 20% will come from the establishment of one-way EAS from Granite Quarry to China Grove and Concord. As noted above, the Public Staff would not oppose a proposal under which 40% or less of the required revenue reduction would come from access reductions, but we cannot support a proposal which would rely on changes in access charges for 80% of the required reduction. Therefore, if House Bill 338 has been signed at the time the Commission's order is issued, the Public Staff recommended that the Commission direct ALLTEL to submit a new proposal that meets the following guidelines: (1) Reductions in access charges should provide 40% of the required revenue reduction. (2) One-way EAS should be established from Granite Quarry to China Grove and Concord and also from Denton to Badin Lake. (3) The remainder of the required revenue reduction should come from uniform reductions in rates for all expanded local calling rate bands.

Barnardsville, Saluda Mountain and Service

Barnardsville proposed to reduce its Expanded Local Calling rates for three routes, Barnardsville to Burnsville, Marshall and Mars Hill, to $.04 per minute and to add Burnsville and Marshall to its $7.00 per month optional flat rate unlimited calling plan. These local reductions slightly exceed the required reduction amount, but the Company also proposed to reduce its intraLATA toll rates, which now are up to $.51 for the first minute and $.35 for each additional minute, to $.20 per minute during the day period. Night and weekend rates would be reduced accordingly.

The majority of Saluda's proposed reduction would come from a reduction in its touchtone rates from $.95 to $.45. Another portion of the required reduction would come from the elimination of the expanded local calling rates for calls to Lake Lure (Lake Lure to Saluda is one of BellSouth's zero-rated routes), and a reduction from $7.00 to $5.00 in its optional block of five hours for calls to Columbus, Tryon and Green Creek for residence subscribers. Saluda would also reduce intraLATA toll rates to $.20 per minute during the day period, with corresponding changes in night and weekend rates. This is the same long distance rate reduction as proposed by Barnardsville. If House Bill 338 becomes law, the touchtone rate will only be reduced to $.50, and the remainder of the required rate reduction will come from the decreases in toll rates.

Service's proposal is to zero-rate calls to Fairmont, which are now expanded local calls (another of BellSouth's zero-rated routes), and to implement the same intraLATA toll rate reduction as proposed by Barnardsville and Saluda. The Fairmont reduction alone exceeds the required reduction amount.

BellSouth

Approximately 69% of BellSouth's reduction would be obtained by reducing the rates for the shortest two expanded local calling rate bands, the 0 to 10 mile and 11 to 16 mile bands, to zero. This would enable subscribers in the majority of BellSouth's exchanges to call a larger area without incurring usage sensitive charges. In many of the cases the routes terminate to other BellSouth exchanges and would result in full two-way service. This would affect different exchanges differently, increasing the outgoing local calling area of some exchanges by several exchanges and adding no exchanges to other exchanges' outgoing calling area. The exchanges with the lowest number of exchanges in their local calling areas would derive the greatest benefit from this change, and those with large flat rate local calling areas, such as Charlotte and Raleigh, the least. BellSouth calls this portion of its proposal Initiative 1.

Initiative 2 and Initiative 2A are alternative options for producing approximately the same revenue reduction. Initiative 2 would reduce expanded local calling rates in bands above 16 miles, while Initiative 2A would reduce access charges to interexchange carriers. The Public Staff favors

Initiative 2, even if Session Law 2001-430 is amended, for three reasons. First, significant reductions have already been made in BellSouth's access charges. BellSouth's access charges are already the lowest in the State, and they are scheduled to be reduced even further, to a composite of two cents. No evidence has been presented in this case about the cost of access, and proposals to reduce the composite rate to below the two cent level should be considered only after a careful examination of the cost issue. The second reason for preferring that the reductions be taken in rates other than access charges is the difficulties that have arisen in previous cases in getting the IXCs, other than AT&T, to flow the access savings through to their end users. Our final reason for preferring Initiative 2 is that if Initiatives 1, 2A and 3 were adopted, in 13 of BellSouth's 92 exchanges there would be no rate reduction or local service improvement for any subscriber. Initiative 2, on the other hand, would provide a reduction in the expanded local rates for each of BellSouth's exchanges, other than those served out of another state or associated with a LATA in another state. BellSouth's filing indicated that it proposed to reduce access charges rather than expanded local rates (that is, it would implement Initiative 2A rather than Initiative 2) only if Session Law 2001-430 is amended.

Initiative 3 includes the implementation of several carefully chosen Extended Area Service arrangements. The Greensboro/Kernersville route, which was one of the routes that BellSouth originally proposed, has been dropped from the list because it has been pursued through the standard means. (This EAS proposal appeared on the agenda of the Regular Commission Staff Conference on November 26, 2001, and is proceeding toward a poll of the Kernersville subscribers.) BellSouth will revise its filing to remove this arrangement and substitute the Wilmington/Long Beach/Southport EAS proposal.

This substitute proposal and each of the other arrangements has its own particular merit and would benefit the subscribers in those exchanges. In the case of the Raleigh/Creedmoor arrangement, the inverse of the BellSouth proposal, Creedmoor/Raleigh, has been included by Verizon South in its revised tax flow-through filing of November 21, 2001. As a result, each of the remaining arrangements can be implemented on a full two-way EAS basis. BellSouth will provide white page listings for the additional EAS points to its subscribers. BellSouth is prepared to move forward with these arrangements effective January 1, 2002.

Together these initiatives present a broad approach that would benefit a wide variety of BellSouth's customers. Six of the nine telephone membership cooperatives in the State (represented by the North Carolina Telephone Cooperative Association) have filed comments expressing reservations about Initiative 1. While BellSouth's proposal certainly is not perfect, the Public Staff believes that it represents a worthwhile effort to expand the outgoing calling areas of many of BellSouth's most isolated exchanges.

<u>Carolina/Central</u>

Both Carolina and Central proposed elimination of their touchtone rates and reductions in their ELCA rate schedule in order to meet the net tax reduction. Central's touchtone rates would be reduced from $.22 for residence and $.50 for business to zero for both. Carolina's existing touchtone rates of $.18 and $.50 for residence and business respectively would be reduced to zero. This would account for approximately 28% to 30% of the total required reductions. The remainder of the reductions would be taken in the ELCA usage rate schedules, which apply to all of these companies' subscribers except those with the Value Caller option.

The Carolina/Central proposals produce the required revenue reduction for Central, but additional reductions are required to produce the required reduction for Carolina. As part of its compromise settlement with the Public Staff, Carolina has agreed to file a proposal for the necessary additional reductions by December 11, 2001. The Public Staff will review this filing and notify the Commission if it does not appear to be acceptable.

Citizens

Citizens has proposed to eliminate the $.03 per call charge in its current ELCA schedule. This will greatly simplify the schedule, making the rates for the first and additional minutes the same, and will produce $125,764 in revenue reductions. In a revised filing on November 30, Citizens further proposed to reduce its non-published number rate from $1.50 to $1.40. The total effect of these two proposals slightly exceeds the required revenue reduction.

Concord

Concord calls its expanded local calling plan the Metro plan. The default plan, the Standard Metro Plan, carries no monthly rate but offers 30 free minutes of outgoing calling within the Metro area per line per month. Usage in excess of the 30 minutes is billed at $.10 per minute. In addition to the standard plan, Concord offers three optional plans for business and residence service. Each of these plans provides a block of outgoing calling minutes within the Metro area for a monthly rate. A fourth option, the Unlimited Calling Plan, is available to residence subscribers only. The monthly rate for each if these optional plans is in addition to the basic monthly rate for local service.

Under Concord's revised proposal filed on November 30, the Company would reduce its rates for expanded local plans. The reduction that would affect the largest number of subscribers is a decrease in the Standard Metro Plan's rate for expanded local calling (beyond the 30 free minute allowance) from $.10 to $.09. Approximately 85% of Concord's business and residence subscribers use this plan. The revenue reduction produced by this rate change amounts to approximately 38% of the total required revenue reduction.

The remaining reductions would be taken in two of the four optional local calling plans, Metro Option 2 and the Unlimited Option. These changes would affect residence subscribers only; the rates for business subscribers on Metro Option 2 would not be reduced.

Metro Option 2 carries a monthly rate of $15.00 and provides 370 minutes per line per month of outgoing expanded local usage. Additional minutes are billed at $.08 instead of the current standard Metro rate of $.10. Of Concord's 117,674 access lines, 1,981 are residence lines subscribed to Metro Option 2 and will benefit from this reduction.

Concord's Unlimited Metro option carries a monthly rate of $18.50 and provides unlimited calling to points within the Metro area. 8,989 of Concord's access lines are arranged for this service.

Concord's proposal is to lower the monthly rate for both of these plans and to reduce the per minute rate for Metro Option 2 from $.08 to $.07, for residence customers. The monthly rate for the Metro Option 2 would be reduced from $15.00 to $12.00 for residence subscribers. It would remain at $15.00 for business subscribers, and business subscribers would also continue to pay $.08 per minute. The monthly rate for the Unlimited Metro Option would be reduced from $18.50 to $12.95.

Although Concord has proposed to take a great deal of the required revenue reduction in plans that are not currently very popular, the reductions will make these plans more attractive to a wider portion of Concord's subscribers. By subscribing to those plans at the reduced rates, additional subscribers can realize savings as a result of the reductions.

Ellerbe

Ellerbe has proposed to reduce its basic residence rate by $.48 and its business rates by $.47. These proposals meet the required reduction amount.

LEXCOM

LEXCOM's original filing included only a proposal to reduce its originating carrier common line charge, providing no direct reduction to its end users, and producing approximately $9,500 less than the required reduction amount. On November 27, LEXCOM revised its proposed access reduction to slightly exceed its required revenue reduction.

On December 7, 2001, LEXCOM and the Public Staff became aware that LEXCOM's original proposal and the November 27, 2001, revision had been based on mistaken assumptions as to the amount of the revenue reduction that would be generated by lowering the originating carrier common line charge. Late Friday afternoon, December 7, LEXCOM filed a new proposal, which provides for a reduction of the originating carrier common line charge to zero, a reduction in touchtone charges, and reductions in ELCA rates. Under LEXCOM's new proposal, less than 40% of the total revenue reduction is produced by access charge reductions. The Public Staff has not had time to complete its review of LEXCOM's new proposal and will report it recommendations on this proposal to the Commission by Wednesday, December 12, 2001.

MEBTEL

MEBTEL's original proposal produced a significantly lower revenue reduction than appropriate. Subsequently, MEBTEL discussed two alternative proposals with the Public Staff, both of which would produce the correct revenue reduction. MEBTEL prefers the first alternative and filed it with the Commission on November 29. This proposal would establish a uniform rate of $.08 per minute for all ELCA calls. At present the rate is $.15 for the first minute and $.10 for each additional minute for on-peak calls, and $.105 for the first minute and $.07 for each additional minute for off-peak calls. Under the November 29, 2001, proposal the rates for most ELCA calls would be reduced, but the rates for off-peak calls over 4 minutes in length would increase. The Public Staff believes that rates should not be increased in a proceeding that is intended to pass through the effects of a tax reduction to end users, and therefore we cannot recommend this proposal. However, MEBTEL is certainly free to pursue the proposal through regular filings under its price plan.

MEBTEL's second alternative proposal, which it has discussed informally but not filed, includes a set of reductions which avoids increases in the rates for any calls and provides for extension of its expanded local calling plan to the LATA boundary. This proposal would establish more uniform expanded local rates by reducing the day rates of $.15 for the first minute and $.10 for each additional minute to the existing off-peak level of $.105 for the first minute and S.07 for each additional minute. The $.105 and $.07 rates would then apply to all rate periods and all mileage bands. The expanded local plan would also be extended to the LATA boundary. This would dramatically enhance the MEBTEL subscribers' local service.

While the Public Staff cannot recommend MEBTEL's original proposal because it did not reduce rates sufficiently, and cannot recommend the November 29, 2001, proposal because it includes some rate increases, the Public Staff believes that the Company's second alternative proposal is reasonable and should be approved.

North State

North State proposed two options. Option I would greatly simplify the ELCA schedule by eliminating the entire differential between the first and additional minutes, so that the current additional minute rate would apply to both the first and additional minutes. The revenue effect of this option significantly exceeds the required reduction amount.

Option II would be used if House Bill 338 becomes law. This option involves a less dramatic cut in the ELCA rate for the first minute coupled with a reduction of the originating carrier common line access charge to zero. The access reduction would amount to approximately 40% of the total required reduction. North State proposed to wait until the legislative session is completed if necessary to determine whether Section 18 will be modified, and requested that no action be taken on this proposal until that determination is made. The legislature has now adjourned, but the Governor has 30 days from adjournment -- that is, until January 5 -- to decide whether to sign the bill. The Public Staff does not object to North State's Option I, and the Public Staff will not object to Option II if the statute is amended. However, there is a need for quick action in this case, and the Public Staff believes that if the Governor has not signed the bill within a few days, the Commission should proceed with the issuance of its order and approve Option I.

Pineville

Pineville pointed out in its filing that since it is a municipality and does not pay gross receipts tax, it does not anticipate a reduction in expenses and has not proposed a reduction in rates. The Public Staff agrees that no reduction is required from Pineville, and that Pineville should be exempted from compliance with the Commission's Order of October 24.

Randolph

On November 30 Randolph revised its proposal to provide for reductions in the initial minute rates for the last three bands of its ELCA rates, covering calls from 17 to 40 miles. These reductions would produce all of the required revenue reduction and would impact the majority of ELCA calls from Randolph's subscribers.

Verizon

Verizon currently has four basic areas of operation: (1) the Durham and Creedmoor area, including Verizon's portion of the Research Triangle Park, (2) the Monroe, Altan and Goose Creek exchanges in Union County, (3) the exchanges in the western part of the State which formerly belonged to Contel NC, and (4) the Knotts Island exchange. Each of these areas has its own expanded local calling plan, and the plans differ according to the needs and the history of the services. Verizon has proposed different reductions for each area.

Verizon revised its proposal on November 21 to bring its reduction to the appropriate level. On December 7 Verizon filed a further revision. This new revision reflects the cost of the directory listings which are required for the EAS arrangements Verizon has proposed and the zero-rating of the Durham to Chapel Hill route. The cost of these listings was not included in Verizon's prior proposals. In order to provide for these listings, it was necessary to reduce the revenue reduction proposed in the previous filings, and Verizon accomplished this by trimming its previously proposed reductions for the Union County area. The remainder of the reductions would remain as previously proposed. The December 7 proposal would produce the required revenue reduction.

In the Durham and Creedmoor area, Verizon has proposed to zero-rate three current TriWide (ELCA) routes: Durham to Chapel Hill, Durham to Hillsborough, and Creedmoor to Wake Forest. This would represent a major step forward in the resolution of the Chapel Hill-Durham EAS request now pending from the Town of Chapel Hill. It would also enable the dissolution of the Chapel Hill Border plan. Verizon has also proposed to implement EAS between Creedmoor and Raleigh, and between Durham and Pittsboro. The Creedmoor proposal would match the Raleigh to Creedmoor proposal made by BellSouth, and the Durham to Pittsboro proposal would complete Verizon's portion of the EAS arrangement for Durham to Chapel Hill, Hillsborough and Pittsboro.

In the Union County area, the current expanded local calling plan provides calling from the Monroe, Altan and Goose Creek exchanges to Charlotte at expanded local rates. Verizon has proposed to reduce the per call charge for calls to Charlotte from \$.06 to \$.015. The other proposal affecting this area is the establishment of EAS between Goose Creek and BellSouth's Locust exchange. The Goose Creek proposal would correspond to BellSouth's zero-rate proposal for its Locust exchange.

In the former Contel NC area, Verizon has an optional expanded local calling plan in place. There are four residence options and two business options. The monthly rate for each option varies according to the number of exchanges that may be called on a flat rate basis, and the number of exchanges in the expanded local area. The plan has achieved limited acceptance from customers, partially because of the limited size of the expanded local area. Verizon's proposal for this portion of its service area is focused on enhancing the two most popular of these options, the Community Plus Option and the Premium Option. The first of the proposed enhancements is to zero-rate all calling to existing local calling plan exchanges that are within 16 miles of the calling exchange, which would include 28 specific routes. This would benefit only the Community Plus subscribers.

The second proposed enhancement is to add five routes to the calling plan and zero-rate those routes. These routes are currently long distance routes and are less than 16 miles in length. This change would enhance the Community Plus Option and the Premium Option for subscribers in the affected exchanges.

The third enhancement would add to the plan all intraLATA toll routes that are 17 to 40 miles in length. All subscribers to any of the four optional calling plans would benefit from this enhancement.

The Knotts Island exchange does not have an expanded local calling plan, but it does have a very large local calling area, primarily in Virginia. Reductions to its subscribers will be provided by eliminating the nonrecurring charge for subscribing to touchtone service.

Summary and Recommendations

The Public Staff recommended that the following companies be allowed to proceed with their reductions as they have proposed:

Barnardsville
BellSouth (Initiatives 1, 2 and 3, revised to include the Wilmington, Southport and Long Beach EAS arrangement)
Central
Citizens (revised proposal)
Concord (revised proposal)
Ellerbe
North State (Option I, unless House Bill 338 has become law when the Commission's order is issued)
Pineville (no reduction)
Randolph (revised proposal)
Saluda Mountain
Service
Verizon (December 7, 2001, proposal)

The Public Staff recommended that Carolina be allowed to proceed with the reduction it has already proposed and the additional reductions to be proposed in its filing pursuant to its compromise agreement with the Public Staff, unless these additional reductions are found not to be acceptable.

The proposals of the remaining companies either present serious problems or were filed too late for the Public Staff to review them. The Public Staff's recommendations as to these companies are summarized below:

ALLTEL – The Public Staff recommended that the Commission direct ALLTEL to file a proposal that follows the guidelines set out above.

LEXCOM – The Public Staff stated that it would provide the results of our review of LEXCOM's latest revised plan to the Commission by December 12, 2001.

MEBTEL – For the reasons discussed above, the Public Staff recommended that MEBTEL be directed to file and implement its second alternative plan, which the Company has discussed in detail with the Public Staff, but has elected not to file.

Accordingly, the Public Staff recommended that the plans of the eleven companies identified above be allowed to become effective, subject to review of their tariffs and customer notices, on billings on and after January 1, 2002; that Carolina's plan be allowed to become effective on billings on and after January 1, 2002, subject to review of its additional filing pursuant to its compromise agreement with the Public Staff and to review of its tariffs and customer notices; that the plans of ALLTEL and MEBTEL be modified as indicated above and refiled; that the Commission allow the Public Staff to submit its recommendations as to LEXCOM's new proposal on or before December 12, 2001; that the companies be instructed to file proposed customer notices and tariffs in accordance with their proposals by December 17, 2001; and that the Commission direct each company to notify its customers of its rate reductions by an insert in the bill received by the customer in December 2001 or January 2002, or by a direct mailing sent to the customer on or before January 15, 2002.

ILEC and Other Responses

Mr. Dan Higgins, representing ALLTEL and the North Carolina Cooperative Coalition (NCCC) and others, addressed issues regarding ALLTEL, LEXCOM, and Randolph. With respect to ALLTEL, Mr. Higgins noted that ALLTEL's latest proposal was 80% devoted to reduction of access charges, the balance devoted to certain one-way EAS proposals. He argued that this was a reasonable figure and that the 40% figure advocated by the Public Staff was arbitrary. ALLTEL is amenable to include Badin Lake in its proposal. With respect to LEXCOM and Randolph, Mr. Higgins stated that they were supportive of the comments filed by the NCCC which argued the negative effects of one-way EAS proposals, including revenue loss potential. The Commission should suspend BellSouth's proposal as to LEXCOM and Randolph to give more time for further negotiations.

Mr. Trey Judy of MEBTEL argued in favor of MEBTEL's proposal as beneficial to the company and its customers. Certain discrete rate increases are not barred when part of a general reduction.

Mr. Dwight Allen of NCCC (consisting of 9 TMCs) specifically expressed concern about one-way EAS to 23 BellSouth EAS routes affecting TMCs. One-way EAS distorts calling patterns, and the TMCs have no tax money to offset increased call volume costs. There will also be pressure to go to two-way EAS, which also can cut into revenue. Skyline TMC, for example, might have to increase its rates by $2.00 to $3.00. The TMCs have had discussions with BellSouth but with no satisfactory solutions have been reached. Routes involving TMCs ought to be suspended from the proposals, so that further negotiations can take place.

Mr. Ed Finley, representing BellSouth, supported BellSouth's proposal and responded to comments made by various parties. He warned against modifying the plan by exempting certain parties from its impact. He expressed skepticism that the impact on the TMCs would be significant. Finally, BellSouth argued for its Initiative 2A, which would further reduce its access rates.

Mr. John Policastro of AT&T of the Southern States, Inc. (AT&T) argued that, in light of the recent amendment, reduction of access charges should be a significant element in the various proposals. He argued that the Public Staff's 40% limitation was arbitrary, and concerns about enforcement flow-throughs are not an argument against access charge reduction. He did not, however, argue for cross-the-board access charge reductions applicable to all companies.

Mr. Richard Reese of LEXCOM explained elements of LEXCOM's revised proposal.

On December 12, 2001, the Public Staff submitted a letter stating that it had completed its review of the revised rate reduction plan of LEXCOM and believed it to be acceptable. The Public Staff likewise has reviewed the revised rate reduction plans of Carolina and Central and finds them to be acceptable as well.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes as set out below. Before listing these conclusions, however, the Commission wishes to discuss two matters.

The first has to do with access charges. The recent amendment to Section 18 of House Bill 571 has enlarged Commission discretion to include the reduction of access charges. Some companies have proposed to utilize portions of the tax reduction for that purpose to reduce access charges. The Public Staff has been agreeable to the use of such funds up to 40% as an upper limit. The Commission believes that both access charges and other rate adjustments are worthy objects for reduction. The issue is the appropriate balance between them. Not even AT&T has argued for an across-the-board application of access charge reductions to all companies. The Commission believes that, given the circumstances of this docket, it is reasonable to allow the access charge reductions that a company has most lately proposed.

The second matter relates to some companies' (most notably, the TMCs') pleas to be exempted from the one-way flat-rate ELCA calling proposals put forth by certain companies. While the Commission is not unsympathetic to the circumstances of these companies, the Commission does not believe that they have made a sufficient demonstration of significant harm that would justify suspending these routes. Accordingly, the Commission concludes that their requests should be denied.

The decisions as to the ILEC proposals are set out below:

1. The proposals of Barnardsville, Central (revised proposal), Citizens (revised proposal), Concord (revised proposal), Ellerbe, North State Option II, Pineville (no reduction), Randolph (revised proposal), Saluda Mountain, Service and Verizon (December 7, 2001, proposal) are allowed.

2. Carolina's revised proposal which provides for the required revenue reduction pursuant to its compromise agreement with the Public Staff is allowed.

3. ALLTEL's alternative proposal distributing 80% of the required revenue reductions to access charges is allowed with the proviso that the balance of savings are to be used to implement EAS between the Granite Quarry, Concord and China Grove exchanges and between Denton and Badin Lake. Reductions in expanded local rates for all exchanges (if additional reductions are required) are allowed subject to the filing with the Public Staff of the required workpapers and the Public Staff's review and comments.

4. LEXCOM's December 7, 2001, proposal is allowed.

5. MEBTEL's second alternative proposal is allowed.

6. BellSouth's Initiatives 1, 2A, and 3, amended by its filing of December 7, 2001, are allowed.

IT IS, THEREFORE, ORDERED as follows:

1. That the plans of the companies as set out in Conclusions 1-6 be allowed to become effective, subject to review of their tariffs and customer notices, on billings on or after January 1, 2002.

2. That MEBTEL file its second alternative proposal agreed to by the Public Staff.

3. That the ILECs file proposed customer notices and tariffs in accordance with their proposals by December 19, 2001.

4. That each ILEC shall notify its customers of its rate reductions by an insert or a bill message in the bill received by the customer in December 2001 or January 2002 or by a direct mailing sent to the customer on or before January 15, 2002.

5. That the facilities-based long distance carriers be sent a copy of this Order and be directed to submit proposed tariffs and supporting workpapers as previously required by the Commission's June 15, 1999, Order in Docket No. P-100, Sub 72 in order to pass through the access charge reductions to end users. Such tariffs shall be filed by January 15, 2002, with an effective date of January 1, 2002. Companies with reductions that are considered de minimis and too administratively burdensome to accomplish shall file letters attesting to such.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb121001.02

DOCKET NO. SP-100, SUB 19

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Request for Declaratory Ruling) ORDER DEFERRING RULING
by Iredell Landfill Gas, LLC)

BY THE COMMISSION: On July 18, 2001, Iredell Landfill Gas, LLC (Iredell) filed a Request for Supplemental Declaratory Ruling in the present docket which described certain proposed activities and asked the Commission to rule that Iredell would not become a public utility within the meaning of G. S. 62-3(23) by virtue of conducting these activities. The requested ruling would supplement a prior declaratory ruling that was issued in this docket on August 14, 2000. That prior declaratory ruling held that Iredell's sale of landfill gas to a single customer would not cause it to become a public utility. By this supplemental request, Iredell asks that it be allowed to sell landfill gas to as many as three customers by a distribution pipeline of up to twelve miles.

The Commission issued on Order on July 24, 2001, requesting comments. The Public Staff filed comments on August 22, 2001, and Public Service Company of North Carolina, Inc. (PSNC), filed a petition to intervene, which was allowed, and protest on the same date. By subsequent orders, the Commission scheduled an oral argument which was held on December 5, 2001.

From statements made during oral argument, it appears undisputed that Iredell has found one customer to buy its landfill gas, that this one customer cannot buy enough gas to make the project economically feasible, that Iredell has not yet constructed any pipeline or distribution facilities, and that the landfill gas is now being collected and flared at the site.

Iredell asks the Commission to rule that it will not become a public utility within the meaning of G.S. 62-3(23) by virtue of conducting the activities described in its supplemental request. G.S. 62-3(23)a defines a "public utility" as a person:

> [O]wning or operating in this State equipment or facilities for:
>
> 1. Producing, generating, transmitting, delivering or furnishing electricity, piped gas, steam, or any other like agency for the production of light, heat or power to or for the public for compensation....
>
> 5. Transporting or conveying gas...by pipeline for the public for compensation.

The standard for determining whether any given enterprise is a public utility was discussed by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Simpson, 295 N.C. 519, 246 S.E.2d 753 (1978). The Simpson case gives the Commission considerable flexibility in determining the meaning of the phrase "the public." The opinion states,

> [W]hether any given enterprise is a public utility does not depend on some abstract, formalistic definition of "public" to be thereafter universally applied. What is the "public" in any given case depends rather on the regulatory circumstances of that case. Some of these circumstances are (1) nature of the industry sought to be regulated; (2) type of market served by the industry; (3) the kind of competition that naturally inheres in that market; and (4) effect of non-regulation or exemption from regulation of one or more persons engaged in the industry. The meaning of "public" must in the final analysis be such as will, in the context of the regulatory circumstances . . . accomplish "the legislature's purpose and comport with its public policy."

295 N.C. at 524, 246 S.E.2d at 756-57 (citations omitted).

Landfill gas is a natural product of the decomposition of solid waste in landfills. It can pose public health and safety problems, and owners of certain large landfills are required to monitor, control, and dispose of landfill gas. Without projects such as the one proposed herein, such landfill gas will be flared, producing pollution and no economic benefits. The Commission has considered a number of requests for declaratory rulings concerning landfill gas recovery projects. In each case, the Commission has examined the totality of the circumstances set out in Simpson plus other circumstances relevant to the public policies of the State to determine whether the proposed project should be considered a sale or conveyance of gas to or for "the public." One circumstance that the Commission has considered is the public policies favoring productive use of landfill gas. In a declaratory ruling issued for a landfill gas recovery project on May 24, 1996, in Docket No. SP-100, Sub 6, the Commission concluded that it is appropriate to consider environmental benefits in ruling on a request for a declaratory ruling such as this one. The Commission stated:

> First, we note that the Federal government has encouraged development of landfill gas recovery projects. The definition of nonconventional fuels for purposes of federal income tax credits under Section 29 of the Internal Revenue Code includes landfill gas. 26 USCA 29(c)(1)(B)(ii) The EPA promotes use of landfill gas as a medium BTU fuel to replace or supplement other fuels through its Landfill Gas Methane Outreach Program. Standards for new and existing solid waste landfills were recently promulgated by the EPA, and the State is required to implement these guidelines. 61 Fed. Reg. 9905 (1996) Finally, the Federal Resource Conservation and Recovery Act declares it the policy of the United States to develop alternative energy sources in order to reduce dependence on fuels such as petroleum, natural gas, nuclear and hydroelectric generation. 42 USCA 6901(d)02) This policy will be served by the recovery and reuse of landfill gas. In terms of State law, the General Assembly found in the Solid Waste Management Act of 1989 that, "The failure or inability to economically recover material and energy resources from solid waste results in the unnecessary waste and depletion of our natural resources; such that, maximum resource recovery from solid waste and maximum recycling and reuse of the resources must be considered goals of the State." G.S. 130A-309.03(a)(5) The Act mandated that municipalities utilize all means reasonably available to promote the economical recovery of energy resources from solid waste, including contracting for operation of resource recovery services or facilities. This policy is served by the present proposal.

> Further, the State policy of encouraging harmony between public utilities and their users and the environment, G.S. 62-2(5), will be served by non-regulation of landfill gas projects such as this one. Other State policies set forth in G.S. 62-2(1) and (3) emphasize the "fair regulation of public utilities in the interest of the public" and "promot[ing] adequate, reliable and economical utility service to all of the citizens and residents of the State." These policy statements support a holding that [this proposed project] should be exempt from regulation. The proposed project addresses the requirements that cities and counties deal with landfill problems.

The Commission continues to believe strongly that the productive use of landfill gas is in the public interest and should be encouraged.

While the environmental considerations remain the same, other circumstances identified for consideration by Simpson cannot be adequately weighed in this case because Iredell has not yet identified its potential customers. Without knowing the identity of Iredell's customers, we cannot weigh such factors as the distance and location of the new pipeline that will be necessary to serve the customers or the natural gas sales by PSNC that might be displaced. Although Iredell has proposed certain limitations as to number of customers and distance of pipeline, still, granting its request at this time would amount to a blanket ruling that would be inappropriate under the rationale of the Simpson case.[1] The Commission therefore concludes that it must defer ruling at this time. At such time as Iredell can identify its proposed customers, it may renew its request and the Commission will proceed as appropriate. In the meanwhile, the Commission encourages all parties to work in a cooperative spirit to help the State realize the environmental benefits of landfill gas recovery projects such as this one.

IT IS, THEREFORE, ORDERED, that ruling should be deferred, without prejudice, as hereinabove provided.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg121801.03

[1] Two previous cases in which the identity of all customers was not known at the time of the Commission's declaratory ruling are distinguishable. The Westmoreland-LG&E Partners case, Docket Nos. SP-77 and SP-100, Sub 2, involved a sale of steam, which presents a different analysis since there are no regulated steam public utilities. The N. C. Municipal Landfill Gas case, Docket No. SP-100, Sub 18, presented exigent circumstances since an existing, operating facility had lost its initial customer, the local gas utility did not object, and limitations were imposed.

DOCKET NO. E-7, SUB 669

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Jerry Neal and Others, 4121 Humber Court, Charlotte, North Carolina 28215 and Patricia Root, 4118 Humber Court, Charlotte, North Carolina 28215, Complainants v. Duke Power Company, a Division of Duke Energy Corporation, Respondent	)	RECOMMENDED ORDER DENYING COMPLAINT

HEARD: Wednesday, October 4, 2000, at 7:00 p.m., Hickory Grove Branch Library, Charlotte, North Carolina

BEFORE: Hearing Examiner Sam Watson

APPEARANCES:

For the Complainants:

No attorney of record

For Duke Power Company:

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

WATSON, HEARING EXAMINER: On May 16, 2000, Jerry Neal filed a letter with the Consumer Services Division of the Public Staff - North Carolina Utilities Commission on behalf of himself and several neighboring land owners complaining about certain tree trimming practices of the Respondent, Duke Power Company, a division of Duke Energy Corporation (Duke). On May 19, 2000, John and Patricia Root filed a similar letter with the Public Staff. Specifically, the Neals, Roots, and others (collectively, Complainants) complained about Duke's policies with regard to the cutting of trees outside of Duke's transmission right of way.

On May 25, 2000, the letters were filed as a formal complaint with the Commission. The complaint was served on Duke by Commission Order of May 25, 2000, and Duke filed its Answer and Motion to Dismiss on June 5, 2000. Duke's Answer was served on Complainants who requested a hearing. A hearing was scheduled for October 4, 2000, at 7:00 p.m. in Charlotte, North Carolina.

On October 3, 2000, the Public Staff filed its Statement of Position.

The case came on for hearing, as ordered, on October 4, 2000. Jerry Neal, Patricia Root, and John Root testified for the Complainants; Lonny Schmid testified for Duke.

Based upon the pleadings, the testimony and exhibits received into evidence at the hearing, and the record as a whole, the Hearing Examiner makes the following:

FINDINGS OF FACT

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

2. Complainant Jerry Neal resides at 4121 Humber Court, Charlotte, North Carolina; Complainants John and Patricia Root reside at 4118 Humber Court. The Complainants live in the Brantley Oaks subdivision and are customers of Duke.

3. In 1965 Duke purchased a right of way, as evidenced by a Right of Way Agreement, from Dorothy K. and Thomas McMillan for the construction of a transmission line known as the Harrisburg-Wilgrove line.

4. The Harrisburg-Wilgrove transmission line is located along the Complainants' property.

5. The differences in Duke's right of way maintenance procedures between high voltage transmission lines and low voltage distribution lines are reasonable and appropriate based on the numbers of customers served and the unique safety and reliability concerns of each.

6. Duke's interpretation of the Right of Way Agreement to permit cutting of trees which endanger the tower, poles, or wires that composes the transmission line is reasonable and appropriate.

7. Duke's policy requiring the individual land owner to bear the expense of trimming a tree which Duke would otherwise have the right and intent to remove under the Right of Way Agreement is reasonable and appropriate.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

The evidence in support of the findings of fact is found in the testimony and exhibits of the Complainants and the testimony and exhibits of Duke witness Schmid.

In their complaints, the Complainants acknowledge Duke's right of way for the Harrisburg-Wilgrove transmission line and Duke's right to control vegetation within this 68 foot strip of land. The parties are in disagreement, however, over Duke's right and practice of designating "danger" trees outside of the established right of way. The Roots, for example, complain that Duke has identified four trees on their property -- 2 oaks, 1 ash, and 1 poplar -- as danger trees which must be removed or trimmed. Of the five trees identified as danger trees on the Neals' property, Duke removed one at its expense and the remaining four were trimmed at the Neals' expense, for which they seek reimbursement. Citing information obtained from Duke's Internet site, the Complainants dispute that the trees identified by Duke as danger trees are "diseased or damaged," "unhealthy," "structurally weak," or "with poor support in the soil," attributes which they argue are necessary before Duke has the right to remove the trees. The complaints, therefore, present the following three issues for decision: (1) the proper interpretation of "danger" tree; (2) whether danger trees should be trimmed by Duke rather than removed; and (3) who bears the expense of trimming or removing such danger trees.

Complainant Neal testified that Duke first walked the transmission line right of way, marking trees for removal which they deemed to be danger trees. After meeting with the land owners, Duke surveyed the line and identified fewer trees to be removed. Mr. Neal testified that he offered to allow Duke to trim the trees rather than cut them down, which he believed would be cheaper, but that Duke said that it only trims trees along distribution lines. He agreed to have Duke remove one tree and contracted for four more to be trimmed at a cost of $175. He argued that Duke should be responsible in either case since the expense for vegetation management is budgeted and recovered through rates. Mr. Neal also complained about inconsistencies in Duke's policies across their system, testifying that Duke recently trimmed trees rather than removed them in the City of Carrboro. He produced photographs, for example, of large magnolia and pine trees along James Street in Carrboro which appeared inconsistent with the tree trimming policies being enforced in this case. Mr. Neal further complained about Duke's definition of a danger tree. Citing information from Duke's web site that trees which are diseased or damaged might constitute a hazard and need to be removed, Mr. Neal argues that Duke should not be allowed to declare otherwise healthy trees outside of the right of way as danger trees merely because of their height and proximity to the transmission line. Lastly, Mr. Neal testified that the Complainants' concerns about notification of land owners prior to the removal of trees outside of the right of way had been addressed by an agreement entered into by Duke and the Public Staff.

Complainant Patricia Root testified that she and her husband were not aware of the Right of Way Agreement when they purchased their property and that she was "surprised" and "alarmed" when she found out that Duke intended to remove four healthy, old trees from her property. Upon investigation, Ms. Root asserted that "Duke's policy of tree removal along transmission lines . . . was arbitrary and without sound horticultural literacy." She argues that the Right of Way Agreement only allows Duke to remove trees outside of the right of way "that may be a hazard," not simply those trees that, by Duke's definition, are "tall enough to contact conductors, structures, or equipment should the tree fall, be cut or blown toward the lines." Ms. Root cites <u>Evaluation of Hazard Trees in Urban Areas</u>, by Nelda P. Matney and James R. Clark, for the proposition that "a hazard situation requires both the presence of a tree with a potential to fail and a target." She testified that to determine whether her trees had the potential to fail and thus qualify as a hazard tree, she contacted Donald McSween, City Arborist for the City of Charlotte. Mr. McSween did not visit the Roots' property, but responded by letter to Ms. Root indicating that "a hazard tree is one that has a biological condition such as root disease, trunk decay, splitting of the trunk, or upheaval of the ground." She further testified that Mr. McSween "doesn't believe our trees constitute an immediate nor hazard threat." Ms. Root further testified that she contacted Bartlett Tree Research in Charlotte and was informed by letter from Dr. Bruce Fraedrich that "the height of a tree in the absence of defect does not designate the tree as a high risk of failure." She stated that an arborist whom she contacted to come assess the health of her trees, after speaking with Duke, informed her that Duke has a zero tolerance policy along her transmission line due to the fact that it serves a hospital and that there would be no need for him to come out to her property. Upon cross-examination, Ms. Root testified that she had three arborists come out to her property and look at her trees but that none were asked to appear at the hearing.

Complainant John Root testified as to why he believes the trees are so important to his neighborhood: as noise abatement from a nearby highway; as a visual buffer; and as oxygen producers. Quoting G.S. 62-2, he noted that the public policy of the State is to encourage and promote harmony between public utilities, their users, and the environment, e.g., trees. Mr. Root argued that he and his neighbors were "terrorized and harassed." For example, Duke threatened to hold him responsible for any outage caused by trees on his property which Duke was not allowed to remove. Although not raised in the complaint, he stated that Duke cut 29 small trees on his property outside of the right of way which were clearly not hazard or danger trees. Mr. Root reiterated the Complainants' assertion that Duke should pay for tree trimming as well as removal. Lastly, he argued that with the growth of neighborhoods and urban sprawl, Duke's tree trimming policy "needs to be changed, it needs to be documented, it needs to be clarified, and employees of Duke and subcontractors need to know about it."

Duke witness Schmid, a right of way supervisor for the company and a certified arborist, clarified upon direct examination Duke's policy with regard to tree trimming around its transmission lines. He testified that although the Right of Way Agreement gives Duke the right to go back as far as necessary to remove trees that would become a hazard to their line, Duke manages vegetation beneath and around transmission lines within three separate zones: (1) within the purchased 68 foot right of way, or within 34 feet on either side of the center line of the transmission right of way, (2) within a zone that extends an additional 16 feet beyond the right of way, or from 34 to 50 feet on either side of the center line, and (3) beyond the 16 foot zone, or at least 50 feet from the center line. Within the purchased 68 foot right of way, Duke removes any vegetation which would exceed 15 feet tall at maturity. Within the second zone, which is outside of the purchased right of way and where the Complainants' trees at issue in this complaint are all located, Duke removes as a danger tree any tree tall enough to endanger Duke's equipment were it to fall toward the line for any reason. Lastly, within the third zone, Duke removes as a danger tree any tree that is too tall and is dead, diseased, leaning, or dying -- the definition of a hazard tree cited by the Complainants. Thus, stated Mr. Schmid, a tree does not have to be diseased, weak, or leaning to be deemed a danger tree; height alone is sufficient to identify a tree as a danger tree within the first two zones, i.e., within a 100 foot corridor, 50 feet on either side of the center line of the transmission right of way. Mr. Schmid noted that Duke purchases only a 68 foot right of way for transmission lines of the voltage at issue in this complaint, rather than the 100 foot right of way purchased by many utilities, in order to reduce the impact on land owners. With this minimal right of way, however, the Company must preserve its right to remove trees outside of the right of way which endanger the transmission line.

Mr. Schmid further testified that Duke does not trim trees by "topping" them, an incorrect practice in arboriculture, because that may actually weaken a tree and set it up to become a hazard tree. Furthermore, such trimming would need to be done every several years, a practice that would be expensive and impractical since Duke has approximately 10,000 miles of transmission line on its system. Mr. Schmid also testified that some of the trees that had been trimmed by the property owners since the initiation of this proceeding had already grown sufficiently to exceed the allowable height of the tree. Mr. Schmid further testified as to the Company's different policies with regard to tree trimming for distribution and transmission lines. He testified that trees around lower voltage distribution lines may be trimmed, but that danger trees around higher voltage transmission lines are cut because of the potential for more serious damage if the lines are struck. He testified that the Harrisburg-Wilgrove transmission line at issue in this complaint serves more than 25,000 customers and that one circuit serves a hospital, municipal water or sewer facility, or other emergency-type facility. Lastly, he responded to the Complainants' allegations about the trees in Carrboro by noting that the magnolia tree was left as part of a special agreement with the Public Staff, that it is going to be removed in the very near future, and that the pine trees are located in the third zone described above, i.e., outside of the additional 16 foot zone beyond the right of way, or at least 50 feet from the transmission line.

The Public Staff, in its Statement of Position, supported Duke's position herein that its right of way policies are reasonable. As stated by the Public Staff:

> A transmission line outage can cause the loss of power to thousands of customers, resulting in great inconvenience and danger to the public. To prevent such outages, it is necessary for Duke and other power companies to carefully control the growth of trees along their lines. A power company must be allowed considerable discretion in determining whether particular trees should be trimmed or removed due to the danger they pose to transmission or distribution lines. Duke does not appear to have abused its discretion in determining that some of the Complainants' trees should be removed.

Based on the evidence presented, the Hearing Examiner concludes that the Complainants have failed to carry their burden of proof that any relief is due them. G.S. 62-75.

At the outset, the Hearing Examiner is compelled to denounce Duke's pattern of threats and harassment apparent in this case. In addition to the Complainants' allegations of verbal threats by Duke's attorney, Duke stated in a letter to the Commission after the filing of formal complaints in this docket:

> Duke hereby notifies the Commission that if Duke is ordered to further postpone right of way maintenance on this line, and as a result, there is any injury, outage or other damage caused by the trees identified for removal, Duke will hold Mr. and Mrs. Root responsible for any such injury, outage or other damage.

Such intimidation tactics are simply not appropriate. As Duke is aware, any person believed to be aggrieved by the utility has the statutory right to seek redress before the Commission and to be given an opportunity to be heard. Given the limit on the Commission's authority to order monetary relief, it is particularly important in cases such as this that the parties be left in the status quo pending a determination of the propriety of the utility's intended actions. It is not evident to the Hearing Examiner that the Complainants in this case were abusing the complaint process or seeking unnecessary delays in an attempt to resolve their dispute with Duke.

Turning now to the merits of this complaint, the Right of Way Agreement for the Harrisburg-Wilgrove transmission line grants Duke certain rights within and outside a 68 foot strip of land (34 feet on either side) of a survey line as identified in the Agreement. The Agreement further grants to Duke:

> (1) the right at any time to clear said strip and keep said strip clear of any or all structures, trees, fire hazards, or other objects of any nature; (2) the right at any time to make relocations, changes, renewals, substitutions and additions on or to said structures within said strip; <u>(3) the right from time to time to trim, fell, and clear away any trees on the property of the Grantor outside of said strip which now or hereafter may be a hazard to said towers, poles, wires, cables, or other apparatus or appliances by reason of the danger of falling thereon;</u> (4) the right of ingress to and egress from said strip over and across the other lands of the Grantor by means of existing roads and lanes thereon, adjacent thereto, or crossing said strip; otherwise by such route or routes as shall occasion the least practicable damage and inconvenience to the Grantor; provided, that such right of ingress and egress shall not extend to any portion of said lands which is separated from said strip by any public road or highway, now crossing or hereafter crossing said lands. (Emphasis added.)

After carefully reviewing the Right of Way Agreement, the Hearing Examiner concludes as a matter of law that Duke has the right to trim or remove trees outside of the purchased right of way which might fall and contact the transmission line. The Hearing Examiner notes that the term "danger" tree is simply a shorthand term used by Duke to describe such trees. The use of the word "hazard" in the Right of Way Agreement does not limit Duke's right to trim or remove trees to only those trees defined as "hazard" trees in the horticultural literature. Duke has the right to remove trees which "may be a hazard . . . by reason of the danger of falling" onto the transmission facilities.

The Hearing Examiner further agrees with the Public Staff that Duke should be given considerable discretion in determining which trees should be trimmed or removed due to the danger they pose to transmission lines. As part of its franchise, the utility is obligated to provide reasonably adequate and reliable electric service to the consumers within its service territory. The Hearing Examiner concludes that the zonal approach to transmission line vegetation management employed by Duke, as described by Mr. Schmid, appropriately balances the interests of private land owners burdened by the utility's lines and the utility customers' right to receive reliable electric service. For example, since the Right of Way Agreement only gives Duke the right to remove trees that would endanger Duke's facilities, the Complainants may avoid having trees removed by planting lower growing species or by taking steps to reduce the height of the trees so that they are below the height that would result in damage if the tree fell, was cut, or blown onto the transmission line. Duke is not seeking to remove all trees within a 100 foot corridor along its transmission lines; however, it must be allowed to manage reasonable hazards, such as danger trees, that jeopardize the reliability of service to large numbers of customers as are served by its high voltage lines. Duke has preserved its right to do so in this case through the Right of Way Agreement.

The Hearing Examiner commends Complainant Patricia Root for her efforts to investigate Duke's rights under the Right of Way Agreement. Much of the evidence she sought to introduce, however, is inadmissible under the hearsay rule of evidence and was properly objected to at the hearing by counsel for Duke. G.S. 8C-802; G.S. 8C-801(c) ("'Hearsay' is a statement, other than one made by the declarant while testifying at the trial or hearing, offered in evidence to prove the truth of the matter asserted."). Ms. Root, herself not an expert or certified arborist, sought to rely on the statements of other experts to establish that the trees on her property to be removed by Duke were not "hazard" trees. With Duke having no opportunity to cross-examine the authors of the letters produced by Ms. Root since they were not present at the hearing, the statements cannot be admitted to prove the truth of the matter asserted. E.g., 29 Am. Jur. 2d Evidence § 658 (1994). Moreover, even were the evidence to be admitted, the Hearing Examiner finds no inconsistency with Duke's policy since a "danger" tree is not necessarily a "hazard" tree in each of the three zones maintained by Duke along its transmission lines.

The Complainants further argue that the Right of Way Agreement requires Duke to trim, rather than remove, danger trees. However, after carefully reviewing the Right of Way Agreement, the Hearing Examiner concludes that trimming and removal are each options available to Duke under the Agreement. Thus, Duke has the right to trim danger trees as well as to remove them, but is not limited to trimming the Complainants' trees. In this case, Duke has apparently been willing to work with the Complainants to allow the trees to be trimmed rather than removed.

Lastly, some of the Complainants have contracted with third parties to have their trees trimmed rather than removed by Duke and now seek recovery for their trimming expenses. The Complainants argue that since Duke is responsible for vegetation management, the costs of which are included in Duke's rates as an element of their cost of service, Duke should bear the expense of either tree trimming or removal. Duke argues that it should only bear the expense of tree removal, testifying that trimming, which would have to be done more often, would be more expensive. Duke further argues that since the Complainants voluntarily choose trimming rather than having the trees removed in accordance with the Right of Way Agreement, these expenses are not the responsibility of Duke. First, the Hearing Examiner notes that the Commission has limited jurisdiction and cannot award monetary damages such as the reimbursement sought here. With regard to those trees which have not yet been trimmed or removed, the Hearing Examiner concludes that Duke should only be required to pay for the work it elects to perform -- either trimming or removal. Although some level of expense for vegetation management is included in Duke's rates, since they have an option of trimming or removal under the Right of Way Agreement, they should not obligated to pay for the option which they deem to be more expensive. Duke's witness Schmid testified that he believed it would be more expensive to trim the trees rather than to remove them since trimming would have to be done more often, citing the fact that some trees which were trimmed last year in connection with this complaint had already grown too tall again. In addition, while the expense of vegetation management, which benefits all of Duke's customers by ensuring adequate, reliable electric service, is borne generally by

Duke's customers through rates, the Hearing Examiner concludes that it is appropriate for the expense of trimming of specific trees outside of Duke's right of way, which will benefit only the land owner whose trees would otherwise be removed and has no value for the utility's other customers, to be borne by the individual land owner.

The Hearing Examiner expects that Duke will continue to work with the Complainants herein and establish a reasonable schedule by which any danger trees shall be trimmed or removed. Finally, the Hearing Examiner encourages Duke, if it has not already done so, to review the information available on its Internet web site and make changes, where necessary, to ensure that the information presented is easily understandable and consistent with its current vegetation management policy.

IT IS, THEREFORE, ORDERED that the complaint filed in this docket should be, and the same hereby is, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg031501.03

DOCKET NO. E-7, SUB 669

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Jerry Neal and Others, 4121 Humber Court, Charlotte, North Carolina 28215 and Patricia Root, 4118 Humber Court, Charlotte, North Carolina 28215,	)	
Complainants	)	FINAL ORDER DENYING COMPLAINT
v.	)	
Duke Power Company, a Division of Duke Energy Corporation,	)	
Respondent	)	

BY THE COMMISSION: This docket involves complaints filed with the Commission by Complainants Neal and others and by Complainants Root. Both complaints involve tree trimming by Duke Power Company in the same neighborhood in Charlotte and the complaints were scheduled together in this docket. A hearing was held in Charlotte on October 4, 2000, before Hearing Examiner Sam Watson. On March 16, 2001, the Hearing Examiner issued a Recommended Order Denying Complaint in this docket. On April 2, 2001, Complainants Root filed Exceptions to the

Recommended Order. Complainants Neal and others did not file exceptions. On May 22, 2001, the Commission issued an Order scheduling oral argument on the Exceptions.

Oral argument was rescheduled by subsequent orders and was then held as scheduled on July 10, 2001, in the Commission Hearing Room, Raleigh, North Carolina. Complainants Root and Respondent Duke appeared at that time and presented oral argument. During the oral argument, Complainants Root made a motion asking the Commission to reopen the record and to schedule a new hearing for further witnesses. The Commission has carefully considered the oral arguments and the full record herein. On the basis thereof, the Commission makes the following decisions.

First, the Complainant's request to reopen the hearing is denied. The Commission believes that Complainants had a full opportunity to present testimony in support of their complaint at the October 4 hearing and that they have not presented any good reason for being provided with an opportunity to re-litigate their complaint now. Complainants state that a key witness was unable to attend the October 4 hearing; however, they did not make this point at the hearing. At the hearing, complainant Patricia Root testified that she had not asked any of the experts who had examined her trees to come and testify at the hearing. Complainants also cite certain written materials that they presented at the October 4 hearing which was found inadmissible as hearsay by the Hearing Examiner. However, the Hearing Examiner went on to state that even if this material had been admitted, it was not inconsistent with his decision. The Commission agrees. Given the Commission's decision to affirm the Hearing Examiner's interpretation of the right of way agreement, further testimony as to the condition of particular trees or as to the meaning of the terms "hazard tree" or "danger tree" in the horticulture industry would not be determinative.

Second, the Commission affirms and adopts the Recommended Order for the reasons set forth therein, subject to supplementation as set out below. The Commission agrees with findings of fact, the interpretation of the right of way agreement, the conclusions of law, and the ordering paragraphs set forth in the recommended order, as supplemented hereinafter.

Third, the Commission concludes that the Recommended Order should be supplemented in the following respects:

(1) The Commission requires that Duke abide by the conditions set out in the Statement of Position filed in this docket by the Public Staff on October 2, 2000. The Commission believes that the terms and conditions with respect to advance notice as set forth in the Statement of Position (to which Duke agreed prior to the hearing) should be included in the ordering paragraphs of this final order so that they will become orders of the Commission, rather than only terms of an agreement between the Public Staff and Duke. Despite Duke's agreement with the Public Staff to give advance notice whenever danger trees are to be cut outside a transmission right of way, Duke's website, as of the date of this Order, continues to state that "Duke Electric Transmission attempts to cut danger trees for each line on a nine-year cycle. Typically, we do not make contact with property owners before doing the work except in special circumstances or situations." The Commission specifically orders that Duke revise its website and all other written communications to comply with the terms of the Statement of Position and this Order.

(2) The Commission requires that landowners who receive such advance notice shall also be advised of Duke's policies relating to tree trimming in the three zones as presented by Duke's witness at the hearing in this docket, i.e. that all trees within the right of way will be cut, that all trees within an additional sixteen-foot buffer zone on either side of the right of way that are tall enough to contact the transmission line if they fall for any reason will be cut (or trimmed at the landowner's expense), and that all trees outside this sixteen-foot buffer zone that are tall enough to contact the transmission line if they fall and show signs of disease or other weakness will be cut (or trimmed at the owner's expense).

(3) The Commission requires that Duke scrupulously honor the right of way agreements under which it operates. The Commission does not approve of any action by Duke to remove any tree that is not subject to removal under the applicable right of way agreement, as interpreted by the Commission in this proceeding. As the parties noted at the oral argument, remedies for failure to comply with such right of way agreements are available in the General Court of Justice.

Finally, the Commission wishes to note for the record that it understands the importance of these issues to landowners and expects Duke and other electric utilities to implement their necessary tree trimming policies in an environmentally conscious way consistent with G.S. 62-2(a)(5). Proper communication and careful compliance with sound business practices could prevent disputes such as this one from arising or minimize their severity. Further, the Commission looks with disfavor upon efforts, of the type reflected in this record, which seek to implement a recommended order prior to the date upon which it becomes final.

IT IS, THEREFORE, ORDERED as follows:

1. That the motion to reopen the record in this docket is denied;

2. That the Exceptions of complainants Root are denied and the Recommended Order Denying Complaint issued in this docket on March 16, 2001 should be, and the same hereby is, adopted as the final order of the Commission, as supplemented herein;

3. That whenever trees are identified for cutting outside the transmission right of way, the trees will be marked with paint and advance written notice will be left at the door of the property owner; that the notice will include a letter which explains Duke's policies relating to tree trimming in the three zones as presented by Duke's witness at the hearing in this docket and explains to the property owner that if he disagrees with the designation of any of his trees for cutting, he may request Duke to send a representative to re-examine the property and to make a new determination of whether the tree in question endangers any line or structure on the right of way;

4. That Duke shall revise its website and all other written communications to comply with the terms of the October 2, 2000 Statement of Position and this Order; and

5. That Duke shall scrupulously honor the provisions of its right of way agreements while engaging in line clearing and right of way maintenance activities.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg072301.02

Chair Jo Anne Sanford did not participate in this decision.
Commissioner Robert V. Owens, Jr., dissenting in part.

DOCKET NO. E-7, SUB 669

COMMISSIONER ROBERT V. OWENS, JR., DISSENTING IN PART: I respectfully dissent from the Majority's decision in the present case to the extent the decision denies the Complainants' motion to reopen the hearing and affirms the Recommended Order Denying Complaint. I would have allowed the motion to reopen the hearing.

G.S. 62-78(d) in pertinent part provides as follows:

> When exceptions are filed, as herein provided, it shall be the duty of the Commission to consider the same and if sufficient reason appears therefor, to grant such review or make such order or hold or authorize such further hearing or proceeding as may be necessary or proper to carry out the purposes of this Chapter.

In proceedings of this nature, it has been my experience, and it is my understanding, that the Commission typically has granted the parties, particularly complainants appearing without the benefit of legal counsel, considerable latitude in presenting their cases, a practice which I regard as entirely appropriate and commendable. While I realize that significant liberty may have already been extended here, I am of the opinion that the facts and circumstances present in this case justify the granting of additional leeway, that is, at the very least, further hearing, as envisioned by G.S. 62-78(d).

Much of the argument presented by the Complainants in support of their position was based on hearsay, which of course is not admissible as evidence. However, in my opinion, the Complainants, who as previously noted did not have the benefit of legal counsel, were unaware of the hearsay rule and consequently the inadmissibility of certain statements. In consideration of the alleged nature of those statements and the gravity of the consequences of the Commission's decision, no matter whether it ultimately rules in favor of or against the Complainants, I am of the opinion that the Commission should have scheduled further hearing to afford all parties an additional opportunity to fully develop the evidentiary record such that the Commission would be in a far better position to rule on the merits of the complaint, notwithstanding the fact that the parties have previously had an opportunity to do so.

I wish to emphasize that, in taking this position, I do not contend that under the right of way agreement Duke does not have the right from time to time to trim, fell, and clear away any trees on the property of the Grantor, inside or outside of a 68-foot strip, which may be a hazard to its transmission facilities by reason of the danger of falling thereon. It is my view, however, that, at this juncture, the record is evidentially deficient from the standpoint of providing a sound basis from which the Commission could make a reasonably informed judgment as to whether Duke abused its discretion in determining that some of the Complainants' trees should be removed, if the Complainants were unwilling to have the trees trimmed at their expense.

Based on the evidence of record, as it currently stands, it is not at all clear to me that the law requires or that the public interest is served by interpreting the right of way agreement to mean that it conveys an absolute right to Duke to remove any tree the Company might designate as a hazard by virtue of the fact that it might fall and contact its transmission line, without regard to the reasonableness of the criteria Duke uses for purposes of making such a determination. But rather, I am of the opinion, at least at this juncture, that a more appropriate interpretation of the right of way agreement would be that it conveys to Duke the right to remove or trim any tree the Company in its discretion should reasonably determine to be a hazard to its transmission facilities, with reasonable and appropriate industry standards being the criteria for making such a determination. In my mind, until such time as the Commission is in a position to reach a better informed decision as to the appropriateness of Duke's criteria for determining that a hazard exists, it should defer ruling on this matter. Therefore, for the foregoing reasons, I would have granted the Complainants' request for further hearing.

I also wish to voice my disapproval of certain actions taken by Duke in this docket. In doing so, and in the interest of brevity, I would simply note that I am in complete agreement with the Hearing Examiner's having denounced certain aspects of Duke's behavior, as reflected in the Recommended Order, and I am in complete agreement with the Majority's having admonished Duke, in its decision, for Duke's having sought to implement a recommended order prior to the date on which it was to become final. In my view, Duke's deeds in those regards are entirely inappropriate and indefensible.

I concur in and fully support those provisions of the Majority's decision which are supplements to the Recommended Order and such other provisions of the decision to the extent that they are not in conflict with the views and opinions expressed hereinabove.

/s/ Robert V. Owens, Jr.
COMMISSIONER ROBERT V. OWENS, JR.

DOCKET NO. E-7, SUB 693

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for Approval of Agreement between Duke Energy Corporation, Duke/Fluor Daniel, and Babcock Borsig Power, Inc.	))))	ORDER ACCEPTING AGREEMENT FOR FILING AND SCHEDULING ORAL ARGUMENT

BY THE COMMISSION: On June 4, 2001, Duke Energy Corporation (Duke) filed a request, pursuant to G.S. 62-153, for approval of an Alliance Agreement between Duke, Duke/Fluor Daniel (D/FD), and Babcock Borsig Power, Inc. (BBP), for the installation of Selective Catalytic Reduction (SCR) systems at Duke's Belews Creek Steam Station. Under this Agreement, Duke will utilize the same control technology vendor and balance of plant engineer as is being used for the Cliffside Steam Station SCR installation. Duke stated that the Agreement is similar in terms and conditions to the Cliffside agreement that was approved in Docket No. E-7, Sub 678. Duke further stated that, as with the Cliffside agreement, D/FD has an expectation that profit will be included in the fee charged to Duke for the Belews Creek SCR installation. According to Duke, this expectation is driven by high market demand for SCR work and the competing market demands for D/FD's services. Duke stated that because D/FD and BBP were awarded this project as the result of a competitive bidding process, it is seeking an exception to its Code of Conduct to permit it to pay the full contract amount to D/FD from utility accounts. Duke's Code of Conduct provides that the transfer prices for goods and services provided by affiliates to Duke shall be set at the lesser of a competitive price or the affiliate's fully distributed cost.

This matter was presented at the Commission's Regular Staff Conference on September 17, 2001. The Public Staff stated that although it was reasonably satisfied with Duke's efforts to solicit bids for the Belews Creek SCR installation, it did not believe that the bidding process used for the Belews Creek SCR installation was sufficiently competitive to support an exception to Duke's Code of Conduct to permit it to pay the full contract amount to D/FD from utility accounts.

The Agreement provides that unless otherwise approved by the Commission, all profit paid to D/FD shall be paid from non-utility accounts. In light of the Public Staff's position, Duke proposed that the Commission approve the Agreement and allow Duke to be heard further on its request for an exception to the Code of Conduct.

The Public Staff recommended that the Commission accept the Agreement for filing and allow the parties to conduct business under its terms. The Public Staff further recommended that Duke's request for and exception to its Code of Conduct be addressed in briefs and/or oral argument. Finally, the Public Staff recommended that the Commission state in its order that, for ratemaking purposes, its action does not constitute approval of the amount of fees or compensation paid under the Agreement, and that the authority granted by the order is without prejudice to the right of any party to take issue with any provision of the Agreement in a future proceeding.

Based on the foregoing, the Commission is of the opinion that the Public Staff's recommendation should be adopted.

IT IS, THEREFORE, ORDERED as follows:

1. That the Agreement between Duke, D/FD, and BBP for installation of SCR systems at Duke's Belews Creek Steam Station is accepted for filing pursuant to concerning G.S. 62-153.

2. That, for ratemaking purposes, this action does not constitute approval of the amount of fees or compensation paid under the Alliance Agreement, and that the authority granted by this Order is without prejudice to the right of any party to take issue with any provision of the Agreement in a future proceeding.

3. That oral argument on Duke's request for an exception to its Code of Conduct will be heard on Monday, October 22, 2001, at 2:00 p.m. The parties to this proceeding shall file pre-argument briefs not later than, Monday, October 15, 2001.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of September, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb091901.01

DOCKET NO. E-7, SUB 693

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request for Approval of Agreement between	)	ORDER DENYING
Duke Energy Corporation, Duke/Fluor Daniel,	)	EXCEPTION TO
and Babcock Borsig Power, Inc.,	)	CODE OF CONDUCT

BY THE COMMISSION: On June 4, 2001, Duke Energy Corporation (Duke) filed a request, pursuant to G.S. 62-153, for approval of an Alliance Agreement (Agreement) between Duke, Duke/Fluor Daniel (D/FD), and Babcock Borsig Power, Inc. (BBP), for the installation of selective catalytic reduction (SCR) systems at Duke's Belews Creek Steam Station. Under this Agreement, Duke will utilize the same control technology vendor and balance of plant engineer as is being used for the Cliffside Steam Station SCR installation. Duke further stated that because D/FD and BBP were awarded this project as the result of a competitive bidding process, it is seeking an exception to its Code of Conduct to permit it to pay the full contract amount to D/FD from utility accounts.

This matter was presented at the Commission's Regular Staff Conference on September 17, 2001. The Public Staff stated that although it was reasonably satisfied with Duke's efforts to solicit bids for the Belews Creek SCR installation, it did not believe that the bidding process was sufficiently competitive to support granting an exception to Duke's Code of Conduct. In light of the Public Staff's position, Duke proposed that the Commission approve the Agreement and allow Duke to be heard further on its request for an exception.

By Order dated September 21, 2001, the Commission accepted the Agreement for filing and scheduled an oral argument on Duke's request for an exception for Monday, October 22, 2001. The parties were further ordered to file pre-argument briefs not later than Monday, October 15, 2001.

On October 2, 2001, Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene, which was granted on October 5, 2001.

On October 15, 2001, Duke, CUCA, and the Public Staff filed pre-argument briefs. The oral argument came on, as scheduled, on October 22, 2001, with all parties represented by counsel.

BACKGROUND

Duke states that the Agreement in this docket is similar in terms and conditions to the Cliffside agreement that was approved in Docket No. E-7, Sub 678. Unlike Cliffside, the time frame for installation of SCRs at Belews Creek permitted Duke to issue a Request for Proposals (RFP) and to evaluate bids for this project. Duke states, however, that the significant impact of the SCR with balance of plant systems required it to consider bids only from suppliers with an extensive understanding of the units' design. Because utilities in 19 states are simultaneously seeking to comply with new emission limits, demand on equipment suppliers is extremely high. Therefore, notes Duke, even though it was able to issue an RFP and evaluate bids, the market continues to be constrained as other utilities seek these services.

Duke states that it determined that four large boiler manufacturers were the only suppliers with the appropriate level of understanding and expertise, and that only two of those submitted a proposal: B&W (the original equipment manufacturer for Belews Creek) and BBP. Duke states that it determined, based on the initial results of the effort at Cliffside, that D/FD should provide an estimate for providing the SCR as a partner utilizing either B&W or BBP technologies. This decision was predicated on the knowledge of balance of plant issues which D/FD possesses through its history with Duke. Balance of plant issues when fully considered accounted for one-third of the project cost and were critical to unit reliability.

Duke states that the results of the bidding process yielded four fixed-price bids that could be compared: two from non-affiliates and two from D/FD in conjunction with non-affiliates. Duke states that the stand-alone bid proposed by BBP and the BBP/D/FD alliance bid were essentially equal and were substantially better than B&W offerings. Duke further states that converting the BBP/D/FD bid to an alliance arrangement resulted in an additional savings to the project. In addition, notes Duke, the alliance contract provides it much greater control over handling balance of plant issues while sharing the benefit of cost savings and the risk of cost overruns. Unlike fixed prices contracts, which include adders for contingency and do not return any savings to the owner, and cost-plus contracts, which do not create any incentives for savings, the alliance model upon which the Agreement is based incorporates elements of both and ensures that the contractors will forfeit payment of up to 100% of their profit and up to 2% of their actual costs in the event of any cost overruns. Thus, the knowledge that D/FD possesses of the Duke plant systems and its experience with major power plant construction made the BBP/D/FD alliance the preferred alternative.

Duke further states that, as with the Cliffside agreement, D/FD has an expectation that profit will be included in the fee charged to Duke for the Belews Creek SCR installation. According to Duke, this expectation is driven by high market demand for SCR work and the competing market demands for D/FD's services. With the Cliffside SCR installation, Duke paid the profit to D/FD "below the line" from non-utility accounts. The Agreement in this case provides that unless otherwise approved by the Commission, all profit paid to D/FD again shall be paid from non-utility accounts. Duke, however, is seeking an exception to Section D.2 of its Code of Conduct to permit it to pay the full contract amount to D/FD "above the line" from utility accounts.

DISCUSSION AND CONCLUSIONS

In this case, Duke is requesting an exception to the following transfer pricing rule contained in Duke's North Carolina Code of Conduct, which was filed with the Commission in Docket No. E-7, Sub 596 on September 17, 1997:

D. Cost Allocation Standards

2. With regard to the transfer prices charged for goods and services, including the use and/or transfer of personnel, exchanged between and among the Utility and its Affiliates, the following conditions shall apply:

   (ii) For goods and services provided by such Affiliates to the Utility, the transfer prices shall be set at the lesser of a competitive price or the Affiliate's Fully Distributed Cost.

The term "Fully Distributed Cost" is defined in Section A of the Code of Conduct as "all direct costs, including cost of capital, incurred in providing the goods or services in question."

Duke requests the exception to this transfer pricing rule in order to allow Duke to pay the full contract amount, which includes a profit, to its affiliate, D/FD, from Duke's utility accounts. In other words, Duke must seek this exception because the full contract amount exceeds D/FD's fully distributed cost, including the cost of capital. As an alternative to approving an exception to the Code of Conduct, Duke suggests that the Commission use an "operating ratio" method to set a profit margin of at least 8% which Duke may pay D/FD pursuant to its Code of Conduct and the definition of fully distributed cost. If the Commission does not approve Duke's requested exception or Duke's suggested operating ratio alternative, all profit paid to D/FD shall be paid from Duke's non-utility accounts, or booked "below the line."

In considering this issue, the Commission first notes that the transfer pricing rule for which Duke seeks an exception in this case is consistent with condition (o)(ii) in Ordering Paragraph No. 1 in the Commission's Order dated April 22, 1997, in Docket No. E-7, Sub 596, which approved the merger of Duke and PanEnergy Corporation. This condition, along with several others, was included in a Stipulation dated March 7, 1997, between Duke and the Public Staff, which was filed on March 19, 1997, in Docket No. E-7, Sub 596. In its Brief in this case, Duke argues that the transfer pricing rules in its Code of Conduct: impose asymmetrical pricing requirements upon Duke and its affiliates; ignore economic efficiency and can serve to discourage affiliate transactions; go beyond what is necessary to prevent subsidization; and prejudge certain categories of activities as harmful and as such are by design overly broad. In fairness, Duke tempers its criticism of the transfer pricing rules overall by stating that regulatory bodies should be flexible in reviewing specific circumstances. However, Duke agreed to this very transfer pricing rule in the Stipulation cited above.

Duke's stated reason for seeking the exception is because D/FD and BBP were awarded this project as the result of a competitive bidding process. In its Brief, Duke argues that the purpose of the transfer pricing rules is met by the competitive bidding process which it conducted, and that, therefore, allowing Duke to pay D/FD the full contract amount from utility accounts will not harm consumers. Duke adds that applying these rules in a too rigid manner may discourage affiliate transactions that would benefit consumers. The Commission notes, however, as the Public Staff argues in its Brief, that Duke's Code of Conduct contains no exception to the transfer pricing rules if competitive bids are obtained. Rather, as a general matter, competitive bidding simply provides evidence that the affiliate's fully distributed cost is lower than the competitive price, and that, therefore, under the transfer pricing rule, the affiliate's fully distributed cost is the appropriate transfer price.

Duke asserts that the bidding process and the subsequent negotiations which resulted in the Agreement in this case show that this transaction is reflective of the market price, that the Agreement was clearly the most reasonable and prudent approach for Duke to provide SCR technology at Belews Creek, and that, therefore, allowing Duke to pay the full contract amount from utility accounts benefits consumers. The Public Staff also states that the bidding process for the Belews Creek SCR installation was an obvious improvement over the market research Duke used to justify payment under the Code of Conduct of all but the profit charged by D/FD for the Cliffside SCR installation. However, the Public Staff believes that this process was not so competitive as to justify allowing payment of the entire fee to D/FD for Belews Creek. The Public Staff pointed out that the only two non-affiliated bids were for turnkey arrangements. Only one bid was comparable to the D/FD/BBP alliance proposal, namely, the D/FD/B&W proposal, and that proposal was not directly comparable because it was based on a different design process. CUCA also pointed out that Duke received only two fixed price turnkey bids. CUCA opined that fixed price bids are typically priced significantly above cost to include an allowance for potential cost overruns and to capture profits. However, CUCA states that rather than accepting the fixed price bid of its affiliate, Duke then entered into negotiations with D/FD/BBP to execute a cost-plus contract under which it appears to CUCA that the total project cost may exceed the original fixed price if costs escalate beyond current expectations. Consequently, CUCA believes the cost-plus structure of the Alliance Agreement may not be optimal for ratepayers. The Public Staff summarizes that the bidding process was not sufficiently competitive to ensure that the entire fee charged by D/FD in the Agreement was driven by market forces.

After careful consideration, the Commission concludes that Duke has not presented a compelling or unique reason why it should be granted the requested exception to the transfer pricing rules in its Code of Conduct, and that, therefore, the requested exception should be denied in this particular case. If further requests for exceptions arise, such requests will be judged on the individual facts and circumstances in each case.

As to Duke's alternative suggestion that the Commission use the operating ratio method to permit Duke to pay a profit margin to D/FD from its utility accounts pursuant to its Code of Conduct, Duke's own Brief recognizes that G.S. 62-133.1 and 62-146 explicitly authorize the use of this ratemaking methodology only for water and sewer utilities and common carriers. The Commission declines to extend the application of an "operating ratio" method as suggested by Duke in this case.

IT IS, THEREFORE, ORDERED that Duke's request for an exception to the transfer pricing rules in its North Carolina Code of Conduct to permit it to pay the full contract amount to D/FD from utility accounts for the installation of SCR systems at Duke's Belews Creek Steam Station is denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rj110601.06

DOCKET NO. E-22, SUB 380

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application by Dominion Resources, Inc.,	)	ORDER APPROVING
For Authorization under G.S. 62-111 to	)	CODE OF CONDUCT AND
Engage in a Business Combination	)	AMENDING CONDITIONS OF
Transaction	)	MERGER

BY THE COMMISSION: On April 27, 2001, Dominion North Carolina Power (NC Power), a subsidiary corporation of Dominion Resources, Inc. (DRI), filed a petition with the Commission for approval of Final Standards governing the relationships between itself, DRI, their affiliates, and the nonpublic utility operations of NC Power. In its petition, NC Power stated that it and the Public Staff have reached agreement on the Final Standards, which are intended to replace the Interim Standards approved in the October 18, 1999 Order of the Commission in Docket No. E-22, Sub 380, approving the merger of DRI and Consolidated Natural Gas Company (the Merger Order). NC Power attached a copy of the Final Standards (referred to therein as the Code of Conduct) to its petition. NC Power stated that it recommends approval of the Final Standards because they meet the requirements of the Merger Order and are in the public interest.

The Public Staff presented this matter at the Commission's Regular Staff Conference on May 21, 2001. The Public Staff stated that it has reviewed NC Power's petition and agrees with it. The Public Staff further indicated that Regulatory Condition (16) included in Ordering Paragraph No. 1 of the Merger Order states in part:

> NC Power, DRI, their Affiliates, and NC Power's Nonpublic Utility Operations shall be bound by the Interim Standards contained in Public Staff Exhibit 1, once they are approved by the NCUC in this proceeding. The parties have begun good faith negotiations regarding the development of mutually agreeable Final Standards. They intend to continue such negotiations in the future but agree that the approval of the merger should not be delayed while these negotiations go forward.

Ordering Paragraph 3 of the Merger Order approved the Interim Standards. The Public Staff recommended that the Commission issue an Order (1) approving the Code of Conduct, and (2) replacing the Merger Order's Regulatory Condition (16) in its entirety with the following Regulatory Condition:

> (16) NC Power, DRI, their Affiliates, and Virginia Electric and Power Company's Nonpublic Utility Operations shall be bound by the Code of Conduct approved by the NCUC on May 23, 2001. The Code establishes the minimum guidelines and rules that apply to the relationships and transactions among the above-named entities, with the understanding that the NCUC is not precluded from amending the Code at a later date, should circumstances warrant. Such circumstances include, but are not limited to, changes in the structure of NC

Power, DRI, their Affiliates, the Nonpublic Utility Operations, and/or the electric industry.

After careful consideration of NC Power's petition and the Public Staff's recommendations, the Commission concludes that they should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the Code of Conduct Governing the Relationships between Dominion North Carolina Power, Its Affiliates, and the Nonpublic Utility Operations of Virginia Electric and Power Company, filed with NC Power's April 27, 2001 petition in this docket and attached to this Order, shall be, and hereby is, approved.

2. That existing Regulatory Condition (16) included in Ordering Paragraph No. 1 of the Commission's October 18, 1999 Order Approving Merger in this Docket be replaced in its entirety by the following Regulatory Condition:

(16) NC Power, DRI, their Affiliates, and Virginia Electric and Power Company's Nonpublic Utility Operations shall be bound by the Code of Conduct approved by the NCUC on May 23, 2001. The Code establishes the minimum guidelines and rules that apply to the relationships and transactions among the above-named entities, with the understanding that the NCUC is not precluded from amending the Code at a later date, should circumstances warrant. Such circumstances include, but are not limited to, changes in the structure of NC Power, DRI, their Affiliates, the Nonpublic Utility Operations, and/or the electric industry.

ISSUED BY ORDER OF THE COMMISSION.
This the __23rd__ day of May, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

pb052301.01
Contact the Chief Clerk's Office for Appendix

DOCKET NO. E-22, SUB 380

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Dominion Resources, Inc.,)
for Authorization under G.S. 62-111 to Engage) ERRATA ORDER
in a Business Combination Transaction)

BY THE CHAIR: It has come to the Commission's attention that certain dates were inadvertently omitted from Section II.D.3 of the Code of Conduct Governing the Relationships Between Dominion North Carolina Power, Its Affiliates, and the Nonpublic Utility Operations of Virginia Electric and Power Company approved in this docket on May 23, 2001.

The Chair finds good cause to issue this Errata Order amending Section II.D.3 of the Code of Conduct to read as follows:

3. To the extent that NC Power, its Affiliates, and/or the Nonpublic Utility Operations receive corporate services and functions from DRS (or a successor service company), these services and functions may be provided to NC Power and to one or more of its Affiliates and/or the Nonpublic Utility Operations on a joint basis. Such shared services shall be those permitted pursuant to the Commission's January 27, 2000, and January 19, 2001, Orders in Docket No. E-22, Sub 385. Charges for such shared services shall be allocated in accordance with the DRS cost allocation manual filed with the Commission pursuant to the Order Approving Merger in Docket No. E-22, Sub 380 dated October 18, 1999, subject to any changes to those allocations found appropriate by the Commission.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

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DOCKET NO. E-2, SUB 769

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Carolina Power & Light Company's	)	ORDER APPROVING DEFERRED
Petition to Defer Emission Allowance	)	ACCOUNTING TREATMENT FOR
Expenses	)	EMISSION ALLOWANCE EXPENSES

BY THE COMMISSION: On June 12, 2000, in the above-captioned docket, Carolina Power & Light Company (CP&L or Company) filed a Petition pursuant to G.S. 62-30, 62-32, and 62-35 requesting that the Commission authorize the Company to defer sulfur dioxide (SO_2) emission allowance expenses, effective as of January 1, 2000, for recovery in a future general rate case proceeding or by such other means as the Commission may find appropriate. On November 13, 2000, the Commission issued an Order requesting written comments on CP&L's Petition. The Carolina Industrial Group for Fair Utility Rates II (CIGFUR II), Carolina Utility Customers Association, Inc. (CUCA), and the Public Staff - North Carolina Utilities Commission (Public Staff) filed comments. CP&L and the Public Staff filed reply comments. The Attorney General intervened but did not file comments. By Order dated December 18, 2000, this matter was scheduled for oral argument on Tuesday, January 2, 2001, at 2:00 p.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina. The oral argument was held as scheduled. Arguments were presented by CP&L, the Public Staff, CUCA, and CIGFUR II.

Utilization of emission allowances is one of the options available to companies for use in complying with Title IV of the Clean Air Act Amendments of 1990 (CAAA). An emission allowance permits the holder to emit one ton of SO_2 in the designated year of that allowance or any future year. Each utility is given a limited number of allowances by the Environmental Protection Agency (EPA) at no cost.

In order to achieve compliance with clean air requirements nationwide in the most cost-effective manner, a national emission allowance trading system was established. This system provides utilities with high emission control costs the option of purchasing allowances from utilities with relatively low emission control costs. CP&L, having determined the use of emission allowances to be a part of the appropriate strategy for it to follow in meeting clean air requirements, began purchasing the allowances it would need to accomplish its compliance strategy in 1993. The allowances were held in inventory until CP&L began using them on January 1, 2000.

As indicated above, CP&L in its initial filing requested that it be permitted to defer the costs of allowances used for specific recovery in the context of a future proceeding.[1] In its June 12 filing, CP&L also requested waiver of the regulatory condition (Regulatory Condition No. 16) in the Commission's Order approving its merger with North Carolina Natural Gas Corporation (NCNG), in Docket Nos. E-2, Sub 740, and G-21, Sub 377, which states that CP&L will not file for any cost deferral until after December 31, 2004. Regulatory Condition No. 16, in its entirety, reads as follows:

> None of CP&L's base retail electric rates will be increased from the date of an order approving the merger until after December 31, 2004, except for the following reasons: (1) annual fuel cost adjustment proceedings pursuant to G.S. 62-133.2; (2) to reflect the financial impact of governmental action (legislative, executive or regulatory) having a substantial specific impact on the electric industry generally or on a segment thereof that includes CP&L, including but not limited to major expenditures for environmental compliance; or (3) to reflect the financial impact of major expenditures associated with *force majeure*. For purposes of this condition, the term *force majeure* means an occurrence that is beyond the control of CP&L and/or NCNG and not attributable to either's fault or negligence. Without limiting the foregoing, *force majeure* includes acts of nature, like earthquakes, cyclones, rain, tornadoes, hurricanes, flood, fire, acts of the public enemy, war, riots, strikes, mobilization, labor disputes, civil disorders, injunctions-intervention-acts, or failures or refusals to act by government authority; which such party is unable to prevent by exercising reasonable diligence. To qualify as an exception, a *force majeure* event must be reported within 15 working days of its occurrence.
>
> Any request pursuant to these exceptions will include a specification of the reasons for the request and an accurate quantification of the financial impact of the request.
>
> *In addition, CP&L will not file for any cost deferral from the date of an order approving the merger until after December 31, 2004, except for major expenditures to restore or replace property damaged or destroyed by force majeure.* (Emphasis added.)

The Commission's Order granting merger approval is expressly conditioned on the Regulatory Conditions.

Presented below is a summary of the positions of the parties as set forth in their comments, reply comments, and oral arguments.

Summary of Comments

CIGFUR II: CIGFUR II argued that CP&L's Petition should be denied because it is barred by Regulatory Condition No. 16 and is inconsistent with sound ratemaking practices. CIGFUR II

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[1] Such future proceeding might be, for example, a general rate case proceeding, a fuel charge adjustment proceeding or a proceeding involving stranded costs, in the event of deregulation of the electric utility industry at the state level.

stated that the circumstances of the emission allowance purchases have not changed materially since CP&L agreed to Regulatory Condition No. 16 in 1999 and that such condition is an absolute bar to CP&L's Petition, since such costs were not incurred "... to restore or replace property damaged or destroyed by *force majeure.*" CP&L's only stated rationale for request for waiver of Regulatory Condition No. 16 is that the cost of the emission allowances is a "unique governmentally created expense." According to CIGFUR II, that reason is not sufficient to justify a waiver.

As indicated above, CIGFUR II commented that allowing CP&L to defer these emission allowance expenses for recovery in a future general rate case or by other means would not be consistent with sound ratemaking practices. G.S. 62-133 establishes the procedure for fixing rates of public utilities in North Carolina. The circumstances of the purchase of these emission allowances, which were purchased beginning in 1993, do not warrant departure from the statutory scheme for fixing rates by according exceptional treatment to this one cost item. This last point is reinforced by language contained in CP&L's Annual Report to Shareholders for 1999[1].

CUCA: CUCA opposed CP&L's Petition and requested that it be denied. The Phase II SO_2 requirements articulated in the CAAA, and specifically 42 U.S.C. §7651d, have been public since November 1990. Consequently, when CP&L entered into a stipulation with the Public Staff to refrain from filing for any cost deferral until after December 31, 2004, CP&L was actually or constructively aware of its emission allowance expense obligations. CP&L was also aware of its obligations in July 1999 at the time of issuance of the Commission's Order[2] which, among other things, placed the Regulatory Conditions into effect. CP&L failed to contest such implementation. CP&L's Petition utterly fails to identify any reasonable basis for modifying the Commission's Order or abrogating the Joint Stipulation of CP&L, the Public Staff, and NCNG.

Moreover, CP&L has in a contract with CUCA agreed, among other things, to refrain from filing for any cost deferral until January 1, 2005, *except for force majeure* events. The contract to which CUCA refers has been filed in Docket No. G-21, Sub 404, under confidential seal. CP&L's Petition utterly fails to identify any reasonable basis for abrogating the contract with CUCA. CP&L's Petition is in fact a clear breach of the contract.

Finally, CUCA contended that CP&L's Petition to defer emission allowance expenses is an obvious attempt to address prospectively a form of retroactive ratemaking that has been repeatedly held to be unlawful by North Carolina's appellate courts. *See, e.g., State ex rel. Utilities Comm'n*

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[1] "The 1990 amendments to the Clean Air Act require substantial reductions in sulfur dioxide and nitrogen oxide emissions from fossil-fueled electric generating plants. The Clean Air Act required the Company to meet more stringent provisions effective January 1, 2000. The Company will meet the sulfur dioxide emissions requirements by maintaining sufficient sulfur dioxide emission allowances. Installation of additional equipment was necessary to reduce nitrogen oxide emissions. Increased operation and maintenance costs, including emission allowance expense, installation of additional equipment and increased fuel costs are not expected to be material to the consolidated financial position or results of operations of the Company." CP&L 1999 Annual Report, p. 21.

[2] The Order referred to here is the Commission's Order Approving Merger and Issuance of Securities, issued July 13, 1999, in Docket Nos. E-2, Sub 740 and G-21, Sub 377.

v. Edmisten, 291 N.C. 451, 468-69, 232 S.E.2d 184, 194-95 (1977) ("[R]etroactive rate making occurs when an additional charge is made for past use of utility service."). CP&L is not able to pick and choose certain expenses for deferral, just as ratepayers are not able to pick and choose particular revenues for deferral until CP&L's next rate case. In summary, CP&L's Petition is entirely without merit and effectively frivolous.

PUBLIC STAFF: The Public Staff also opposed CP&L's Petition, arguing that it contradicted both Regulatory Condition No. 16 and sound ratemaking principles. Consequently, the Public Staff requested that the Petition be denied.

The Public Staff stated that the purpose of the Regulatory Conditions, including Regulatory Condition No. 16, was to ensure that the merger would have no adverse impact on CP&L's ratepayers and that CP&L's ratepayers would receive their appropriate share of any benefits resulting from the merger. Cost deferrals were included in the Condition because they have the effect of increasing rates in the future and therefore are an indirect or "back door" way of increasing rates. The only exception is "major expenditures to restore or replace property damaged or destroyed by *force majeure*."

When the parties agreed to Regulatory Condition No. 16, they were well aware that CP&L would begin to use its emission allowances in the year 2000. The absence of an exception for this expense is clear evidence that none was intended at the time.

The Public Staff noted that, in support of its Petition, CP&L cited the Commission's Order dated April 19, 1993, in Docket No. E-2, Sub 642, regarding the CAAA compliance strategy of purchasing allowances rather than installing scrubbers to reduce emissions. CP&L also cited the Commission's Order dated January 18, 1994, in Docket Nos. E-100, Sub 70, and E-7, Sub 524, which allowed Duke Power Company, CP&L, and North Carolina Power to accrue carrying costs on their net investment in emission allowances until December 31, 1999, and stated that the overall regulatory treatment of CAAA compliance costs would be addressed in a further order.[1] According to CP&L, one reasonable treatment of these expenses is to defer them until the overall regulatory treatment can be addressed, at which time the reasonableness of the expense can be addressed and CP&L can seek cost recovery. Thus, the basis for requesting an order allowing this deferral is that the expense was incurred to comply with federal law and the regulatory treatment has not yet been addressed.

In commenting on the foregoing, the Public Staff stated that it recognized that CP&L had requested only a deferral and not cost recovery at this time. However, the Public Staff argued that the deferral of ongoing operating costs should not be approved, with or without assurances of cost recovery. CP&L's agreement *not* to file a general rate case before December 31, 2004, and its agreement *not* to seek any deferrals rest on the same fundamental principle. Unlike costs incurred as a result of a hurricane or other *force majeure*, emission allowance expenses are not a unique and

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[1] By Order issued December 6, 1996, in Docket No. E-2, Sub 699, the Commission approved several accounting adjustments proposed by CP&L in response to a petition filed by CIGFUR II with regard to CP&L's earnings. Among those adjustments was the three-year amortization of $2,425,474 in emission allowance carrying costs.

unforeseen event. Moreover, these expenses cannot be said to provide any benefit to future periods that might justify deferral. Instead, this is the type of cost that should be expensed as utilized in the provision of utility service and taken into consideration by the utility in determining whether to file a general rate case.

The Public Staff commented that it cannot be presumed that the emission allowance expenses incurred in 2000 and beyond will not be recovered in current rates and are instead being borne by CP&L's shareholders. An increase in any one expense item does not necessarily result in an operating income deficiency, since it may be offset by decreases in other costs or by increases in operating revenue. Indeed, the $17 million North Carolina retail portion of the emission allowance expense for 2000 is only 1.5% of CP&L's North Carolina retail operation and maintenance expenses for the twelve months ended September 30, 2000. The only way to determine whether an overall operating income deficiency exists is through an examination of the aggregate change in the levels of revenue and costs, in other words, through the mechanism of a general rate case. In the meantime, rates established by the Commission are deemed just and reasonable and sufficient to recover all costs, including expenses that are incurred years after those rates were initially set.

For the foregoing reasons, the Public Staff requested that CP&L's Petition be denied.

Summary of Reply Comments

CP&L: In its reply comments, CP&L argued that its Petition should be granted due to unforeseen circumstances, fundamental fairness, and common sense. The unforseen circumstances to which CP&L referred concern fuel costs. The Company stated that in the spring of 1999 when it was negotiating the Regulatory Condition in question, it had every intention of seeking recovery of the SO_2 allowances consumed during the year 2000 and subsequent years in its annual fuel cases. However, at the time, CP&L was not aware that it would have a large underrecovery of fuel expenses and need a large increase in overall fuel, totaling $80 million, in its year 2000 fuel case. In consideration of the foregoing, CP&L decided that seeking to recover an additional $17 million of SO_2 emission allowance expenses in the year 2000 fuel case would cause undue hardship to its customers.[1] Accordingly, the Company decided not to request recovery of the SO_2 emission allowance expenses in the year 2000 fuel case but rather to seek Commission authorization to establish a deferred account for these expenses. According to CP&L, there would be no harm to customers from the establishment of such a deferred account, since such costs would not be recovered in rates until such time as the Commission determined in a future proceeding that they were just, reasonable, and prudently incurred.

With respect to matters of fundamental fairness and common sense, the Company argued that the provision contained in Regulatory Condition No. 16 prohibiting the deferral of cost was not one

[1] CP&L recognizes that some parties may argue that SO_2 allowance expenses are not properly recoverable through the fuel clause but that is not the issue in this case. All CP&L is requesting at this time is an opportunity to ask for recovery of its SO_2 emission allowance expenses in a future proceeding by creating a deferred account. As explained in CP&L's Petition, whether CP&L should be allowed to recover them either in a fuel case or in a general rate case proceeding will be decided at that time.

of the fundamental concessions extracted from CP&L upon which any party relied in settling the CP&L/NCNG merger case. Indeed, CP&L asserted that its request to defer SO_2 emission allowance expenses has no relationship to its merger with NCNG and that the blind enforcement of the subject prohibition does nothing to further the intent of the prohibition, i.e., to ensure there was no adverse impact on CP&L's ratepayers as a result of the merger.

CP&L further contended that changes in circumstances that occur after rules or regulatory conditions are established must be considered in determining the appropriateness of their enforcement. This is common sense. They cannot be applied in a vacuum. In support of this position, CP&L cited an instance in another docket in which it had, as an accommodation to the Public Staff, provided certain information that the Public Staff had requested although it was not required to do so under the terms of a regulatory condition previously agreed to by the Public Staff.

In conclusion, CP&L renewed its request that it be authorized to defer SO_2 emission allowance expenses, effective as of January 1, 2000.

PUBLIC STAFF: Regarding CP&L's argument pertaining to unforeseen circumstances, i.e., the Company's large underrecovery of fuel expenses, and its subsequent decision to seek deferral of SO_2 emission allowance expenses, the Public Staff stated that it does not question CP&L's intentions. Nothing in Regulatory Condition No. 16 prohibits CP&L from seeking to recover SO_2 emission allowance expenses in an annual fuel case.[1] Nevertheless, while the magnitude of the year 2000 fuel increase may have been unforeseen, the existence and magnitude of the SO_2 emission allowance expenses were known many years prior to the merger case. When CP&L agreed not to increase its base retail electric rates until after December 31, 2004, or to seek any deferrals except as specifically provided in Regulatory Condition No. 16, it surely foresaw that it was limiting its options for recovering these costs other than through current rates.

Regarding CP&L's assertion that there is no harm to its customers from the deferral of SO_2 emission allowance expenses because they will not be recovered in rates until the Commission determines in a future proceeding that they are just, reasonable, and prudently incurred, the Public Staff questions such reasoning. Even if future harm is uncertain, this alone does not justify allowing a utility to defer costs beyond the time period when they should be expensed according to standard accounting principles. Moreover, as stated in its earlier comments, the Public Staff noted that it cannot be presumed that these or any other expenses besides fuel costs are not being recovered in CP&L's base rates. Thus, in the event the Commission allows these expenses to be recovered from customers in a future proceeding, they may well have been recovered twice. This clearly would be harmful to customers' interests.

The Public Staff also disagreed with the Company's assertions that the deferral provision included in Regulatory Condition No. 16 was not one of the fundamental concessions upon which the Public Staff relied in settling the merger case and that such provision was unrelated to the pending request because its purpose was to ensure that the merger would have no adverse impact on ratepayers. The Public Staff stated that, like any settlement agreement, the Joint Stipulation between

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[1] Although the Public Staff believes that SO_2 emission allowance expenses are not properly recoverable in a fuel case, the Public Staff agreed with CP&L that this is not at issue here.

CP&L/NCNG and the Public Staff was the product of give-and-take negotiations. The agreed-upon Regulatory Conditions and Code of Conduct constitute an integrated whole. The weight given by the parties to one provision or another, even if it were ascertainable, is irrelevant to whether a particular provision should be waived. More importantly, if the provision in question were unrelated to the pending request, a waiver would not be necessary.

The Public Staff asserted that there are basically two ways to ensure that ratepayers receive their appropriate share of merger savings. One is to reduce rates. This method is often controversial because of the difficulty of identifying and quantifying savings related to the merger. The other is to use whatever savings are realized to offset future rate increases by prohibiting rate cases and cost deferrals. The second method, which also acts as an incentive to the utility, is the one agreed to in the CP&L/NCNG merger case and embodied in Regulatory Condition No. 16. According to the Public Staff, under CP&L's argument, the utility would be allowed to enjoy all of the merger savings while shifting certain costs to ratepayers; it is the lack of mutuality that the subject Condition prohibits.

In response to CP&L's assertion that rules and conditions cannot be blindly adhered to or applied in a vacuum, the Public Staff stated that conditions should be applied in the proper context; the question is: what is the context? CP&L cited its having provided certain information to the Public Staff that it was not technically required to provide under the terms of a regulatory condition in Docket No. E-2, Sub 763.[1] The Public Staff stated that, unlike the provision in Regulatory Condition No. 16 prohibiting deferrals, the subject condition neither states nor implies that the Public Staff may not seek information that it would have the right to request in the absence of the condition.

Finally, the Public Staff noted that when CP&L filed its petition for deferral last June it immediately made its opposition known to the Company and proposed instead that the accelerated cost recovery of its nuclear generation facilities for units other than the Harris plant, as authorized in Docket No. E-2, Sub 737, be applied to the SO_2 emission allowance expenses. That proposal has never been withdrawn, and the Public Staff continues to believe that it is a fair and reasonable way of handling these expenses.

In concluding, the Public Staff recommended that CP&L's petition for deferral be denied without prejudice to the Company's seeking authority to modify the accelerated cost recovery of its nuclear generation facilities by applying the non-Harris portion to its SO_2 emission allowance expenses beginning in the year 2000.

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[1] This docket concerned CP&L's Petition to Move Two of the Combustion Turbine Generators Approved by the Commission for Installation in Rowan County to Richmond County and an Application for a Certificate of Public Convenience and Necessity to Attach a 160 MW Heat Recovery Steam Turbine Generator to Two of the Combustion Turbines in Richmond County.

Oral Argument

During the oral argument, the parties essentially in substance either reiterated or incorporated by reference the same arguments which they had previously made in written comments and/or reply comments. Those arguments have been summarized above and need not be repeated here.

Notice of Decision and Order

On January 5, 2001, the Commission issued its Notice of Decision and Order in this matter. By this Order, the Commission sets forth its reasoning and the basis for its earlier announced decision.

CONCLUSIONS

After having carefully considered and weighed CP&L's Petition and all aspects of the comments and arguments presented, the Commission concludes that CP&L's request for waiver of Regulatory Condition No. 16 should be granted and that its request to defer SO_2 emission allowance expenses should be granted without prejudice to the Commission's future determination of the appropriate ratemaking treatment ultimately to be accorded such costs. The primary considerations leading to this decision are, in essence, threefold. First, the Commission has not yet addressed the reasonableness of CP&L's CAAA compliance strategy, or for that matter the appropriateness of the compliance strategy of any other jurisdictional utility. Therefore, at this time, the Commission is simply not in a position to render a decision as to whether costs incurred by CP&L related to achieving and maintaining compliance with the requirements of the CAAA were reasonable and prudently incurred, including costs associated with SO_2 emission allowances. The Commission has previously stated that "[t]he forum and timetable appropriate for the examination of the overall regulatory treatment of costs related to achieving and maintaining compliance with the requirements of the CAAA and the establishment of filing requirements will be addressed in a further order of the Commission." Ordering Paragraph No. 7, *Order on Accounting Treatment for Allowances*, Docket Nos. E-100, Sub 70 and E-7, Sub 524 (1994). Thus, the Commission itself has previously found it necessary to defer ruling on this matter until the reasonableness of the costs in question and the appropriate overall regulatory treatment to be accorded such costs can be fully examined in an appropriate forum. The present proceeding is not such a forum. Therefore, at this juncture, the Commission concludes that the most reasonable course of action under the unique facts and circumstances of this case is a decision which continues to defer the examination of the overall regulatory treatment to be accorded the subject costs to a future proceeding. In consideration of the need to defer ruling on the reasonableness of CP&L's overall CAAA compliance strategy, the Commission is of the opinion that it is reasonable to allow CP&L to defer the costs in question until such matter can be fully addressed and examined in the context of an evidentiary proceeding.

Second, because the deferred accounting treatment requested by CP&L is reasonable under the unique circumstances of this case, good cause exists for the Commission to waive the provisions of Regulatory Condition No. 16 due to unforeseen circumstances. In the Order imposing this Regulatory Condition, the Commission specifically found that "[a]ny party with standing may at any time challenge . . . any of the Regulatory Conditions" and that "CP&L and NCNG acknowledge that the Commission may modify the . . . Regulatory Conditions consistent with the public interest." Findings of Fact Nos. 7-8, *Order Approving Merger and Issuance of Securities*, Docket Nos. E-2, Sub 740 and G-21, Sub 377 (1999). In its discussion of the evidence and conclusions, the Commission stated that the Public Staff acknowledged that the Regulatory Conditions are "a work in progress" and that the Commission's complaint procedures and the Regulatory Conditions themselves "allow for changes to be made in [them] as necessary." Lastly, the Commission concluded in that Order that "[t]o the extent unforeseen or unintended issues arise, any interested party may bring them to the attention of the Commission, and the Commission has the authority to take action." With regard to CP&L's instant Petition, the Company argues that the unforeseen circumstances which support a waiver of Regulatory Condition No. 16 primarily concern fuel costs. The Company stated that in the spring of 1999 when it was negotiating the Regulatory Condition in question, it had every intention of seeking recovery of the SO_2 allowances consumed during the year 2000 and subsequent years in its annual fuel cases. However, at the time, CP&L was not aware that it would have a large underrecovery of fuel expenses and need a large increase overall, totaling $80 million, in its year 2000 fuel case. CP&L decided that seeking to recover an additional $17 million of SO_2 emission allowance expenses in the year 2000 fuel case would cause undue hardship to its customers. Accordingly, the Company decided not to request recovery of the SO_2 emission allowance expenses in the year 2000 fuel case, but rather to seek Commission authorization to establish a deferred account for those expenses. The Commission concludes that the requested waiver of Regulatory Condition No. 16 is consistent with the public interest, and that there will be no harm to customers from such waiver and the establishment of such a deferred account, since such costs cannot be recovered in rates until such time as the Commission may determine in a future proceeding that they were just, reasonable, and prudently incurred.

Third, good cause also exists for the Commission to waive the provisions of Regulatory Condition No. 16 as a matter of fundamental fairness. Regulatory conditions should not be blindly applied in a vacuum. All facts and circumstances must be considered in arriving at a reasoned and legally-justifiable decision. As noted above, the Commission, in adopting the Regulatory Conditions, recognized that changes might be necessary and allowed for parties to bring issues, such as this, to the Commission's attention. In this case, it is reasonable and appropriate to waive the Regulatory Condition in question because to do so is consistent with the public interest and the intent of the Order previously entered by the Commission in Docket Nos. E-100, Sub 70 and E-7, Sub 524 on January 18, 1994. To close the door on CP&L at this juncture without affording the Company an opportunity to present evidence on this issue in a future proceeding would be fundamentally unfair to the Company and, consequently, Regulatory Condition No. 16 must be waived.

In concluding, it is emphasized that the Commission's present decision is not intended, and is not to be construed, to imply that the Commission in any way endorses or supports a CAAA compliance strategy that incorporates measures without good cause that continue to contribute to airborne pollution of our environment. Although the Commission has not yet examined the reasonableness of CP&L's CAAA compliance strategy and remains open-minded with respect to this issue, including questions pertaining to the appropriateness of the use of SO_2 emission allowances, the Commission nevertheless strongly encourages CP&L to continue to revisit its decisionmaking processes in this regard and continue to give every consideration to the use of compliance measures and techniques, such as scrubbers, that will directly contribute to the reduction or minimization of airborne pollutants in North Carolina.

IT IS, THEREFORE, ORDERED as follows:

1. That CP&L's request for waiver of Regulatory Condition No. 16 placed into effect by the Commission's Order Approving Merger and Issuance of Securities, issued July 13, 1999, in Docket Nos. E-2, Sub 740 and G-21, Sub 377 be, and the same is hereby, granted.

2. That CP&L's request that it be authorized to defer, effective as of January 1, 2000, the cost of SO_2 emission allowances purchased pursuant to Title IV of the Clean Air Act Amendments of 1990 be, and the same is hereby, granted without prejudice to the Commission's future determination of the appropriate ratemaking treatment ultimately to be accorded such costs.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of January, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg011701.04

Chairman Jo Anne Sanford and Commissioner Sam J. Ervin, IV dissent.

DOCKET NO. E-2, SUB 769

CHAIRMAN SANFORD, DISSENTING: I respectfully disagree with the majority of my colleagues, and I write to explain the reasons that compel me to dissent. Ironically, I agree with the majority that regulatory conditions should not be applied or suspended in a vacuum, and it is that principle which supports my conclusion that CP&L should not be allowed to defer recovery of these operating expenses. In my view, to permit them to do so ignores prior Commission policy, weakens the CP&L-NCNG merger order, and contravenes G.S. 62-80.

The first question is whether deferred accounting is appropriate at all with respect to these $S0_2$ emission allowance expenses. Deferrals are an exception to the principles of rate-of-return ratemaking; they should be invoked judiciously and only when amply justified. In the past, the Commission has reserved deferred accounting for limited situations, generally characterized by the extraordinary nature and/or magnitude of the costs in question. As stated in 1997, the Commission "rarely allows a utility to defer current expenses for future recovery. Deferred accounting treatment is generally authorized only if the costs incurred [are] unusual and material and of such a magnitude that departure from the Commission's more traditional practices is deemed to be warranted from the standpoint of fairness and equity to both consumers and shareholders." Order of April 29, 1997 in Docket No. G-5, Sub 369. Even if there were no other impediment, this standard alone sets a high bar, which CP&L has not cleared. By CP&L counsel's own statement: "Lord knows we're not talking about CP&L drowning from having to write off these expenses." More significantly, CP&L's own 1999 annual report states, "Increased operation and maintenance costs, including emission allowance expense...are not expected to be material to the consolidated financial position or results of operations of the Company." It is clearly contrary to prior Commission policy to allow deferral of expenses that are neither unusual nor material to the financial position of the utility. The Commission, as a quasi-judicial agency, is under an obligation to either apply policy consistently or explain why policy should be changed, but the Commission has done neither.

There is, of course, good reason why deferred accounting is disfavored and it bears discussion. Deferred accounting singles out one item for special treatment. In business, one's expenses, revenues and savings change day-to-day. A new expense today does not necessarily result in an overall operating income deficiency because it may be offset by unexpected new revenues or savings yesterday or tomorrow. A business may not simply pocket all new savings and revenues while passing all new expenses on to customers; all of these must be taken into consideration in setting prices. This principle of free enterprise operation applies with at least equal force to a regulated industry, which cannot be allowed to look to captive customers for payment of expense items without concomitant accounting for the revenues these customers generate. Yet this is precisely what the Commission is allowing CP&L to do. CP&L is allowed special treatment for its emission allowance expenses without any consideration as to whether this expense is offset by new revenues or savings. Examples abound as to why this decision raises troubling issues. CP&L's existing rates, set back in 1988, were calculated and set to allow recovery of $28 million in annual costs for the amortization of abandoned nuclear units; however, this loss has long since been fully recovered and is no longer being incurred by CP&L. This one item of "savings" alone more than compensates for the emission allowance expenses, yet this decision allows CP&L to have both the old savings and recovery of the new expense.* Anticipating the response that CP&L has incurred additional legitimate expenses since 1988, I agree that is true and note as well that they have acquired additional sources of revenue during that period. Only a rate case review would yield a comprehensive picture of the expense and revenue matches and I object in all but extraordinary circumstances to addressing isolated components of expenses in this way.

In support of its decision, the majority states that it would be "fundamentally unfair to the Company" not to allow deferred accounting of the emission allowance expenses. However, the Commission should consider fairness to both consumers and shareholders when deciding whether to allow deferred accounting -- not just fairness to the company.

Another justification given for the majority's decision is that the Commission is simply not in a position to rule on the reasonableness of CP&L's clean air compliance strategy at this time and that therefore the most reasonable course of action is to allow CP&L to defer its costs until the matter can be addressed in an evidentiary proceeding. This justification falls short for three reasons. First, even if CP&L's strategy had been found reasonable, that says nothing about the propriety of deferred accounting for the associated expenses. I have just discussed the standard for deferred accounting and my belief that CP&L has failed to meet it. Second, the majority's justification ignores the fact that CP&L has foregone its right to seek deferred accounting of present emission allowance expenses in connection with the CP&L-NCNG merger case. CP&L counsel stated, "No question that we did not carve out an exception in condition 16 to address these type of expenses, that's correct." Third, by allowing this deferral the Commission essentially gives CP&L the right to recover some level of these expenses if they request it.

*The foregoing $28 million annual cost savings that CP&L is being allowed to keep is not an isolated example. CP&L's current rates are also continuing to recover approximately $21 million annually of costs related to deferrals associated with the post-commercial operations of Harris Unit 1, notwithstanding the fact that such costs, too, have long since been recovered from CP&L's customers.

Condition 16 of the Commission's July 13, 1999 order approving the CP&L-NCNG merger clearly provides that "CP&L will not file for any cost deferral...until after December 31, 2004, except for major expenditures to restore or replace property damaged or destroyed by *force majeure*." This condition was one of several that the Commission imposed in return for approval of the CP&L-NCNG merger. This condition was part of a agreement among certain parties, each of whom presumably gave and took in arriving at a settlement. More significantly, it was one of the Commission's own requirements set forth in the Commission's own order. It was on the basis of these conditions that we made the crucial conclusion to approve the merger, stating that the "benefits, in conjunction with the ... Regulatory Conditions ... justify the Commission's conclusion that the merger is in the public interest." The merger order provided that the conditions might be changed for "unforeseen or unintended issues," but CP&L has not met this standard. The majority cites as an unforeseen circumstance CP&L's decision not to request recovery of emission allowance expenses in its 2000 fuel case because the case already presented substantial unrecovered costs. This was not unintended; it was CP&L's voluntary decision. It is not at all clear that this was unforeseen, either. CP&L's under-recovery of fuel costs in the 2000 case was largely due to the fuel factors set in the 1999 and 1998 fuel cases. In both of those cases, CP&L proposed fuel factors lower than it was entitled to by Commission Rule. CP&L did this to keep its fuel factor stable, but it was reasonably foreseeable that these lower factors would eventually lead to an under-recovery and that is exactly what happened in the 2000 case.

Even if the decision not to seek recovery of emission allowance expenses in the 2000 fuel case is regarded as an unforeseen circumstance, it is a circumstance that relates only to the test period of the 2000 fuel case. At most, such an unforeseen circumstance would justify a waiver of condition 16 **for the expenses involved in the 2000 fuel case only.** Fuel cases are held every year; by no stretch of imagination should a circumstance related to the 2000 fuel case alone justify deferral of all future emission allowance expenses. On what basis does the Commission waive condition 16 and allow deferral of emission allowance expenses indefinitely into the future? The Commission cites no unforeseen circumstance to justify such a far-reaching decision.

If condition 16 can be waived so readily, I fear that other conditions in the merger order may be subject to erosion. In approving the CP&L-NCNG merger, we also ordered that none of CP&L's base rates would be increased until after 2004, except under certain conditions. Does the Commission now send the signal that if CP&L runs into "unforeseen circumstances" making a rate increase desirable before then, it may apply for waiver of this condition, too?

I specifically reject CP&L's argument that there is no harm in waiving condition 16 since rates are not being changed now. Clearly, there is harm now because the standard for setting rates in the future to reflect the emission allowance expenses has been changed and has been relaxed. Condition 16 barred deferred accounting of emission allowance expenses before 2005. With condition 16 waived and deferred accounting allowed, CP&L need only show that the expenses are prudent to recover them. CP&L counsel acknowledged that "absent a finding of imprudence" some level of these expenses could be recovered ("I don't think the Commission could legally say you're not allowed to recover any of your Clean Air Act compliance cost.").

Finally, I do not believe that the Commission's decision can be defended under G.S. 62-80, which sets forth the terms under which the Commission may reconsider its orders at any time. First, G.S. 62-80 requires that the procedures for a complaint hearing must be used before a prior order is amended. Commissioner Ervin addresses this issue in his dissent. Second, the Commission may not arbitrarily amend a prior order; it must appear that there was a misapprehension of fact or a change of circumstances requiring amendment in the public interest. I believe CP&L has failed to show such good reason for reconsideration, as I have previously argued. Third, the July 13, 1999 Order which imposed condition 16 weighed benefits and costs and found as a fact that the "known, expected and potential benefits of the merger are at least as great as the known, expected and potential costs and risks." That order made the regulatory conditions "express conditions of approval of the [CP&L-NCNG] merger" and stated that the benefits of the merger "in conjunction with the...Regulatory Conditions...justify the Commission's conclusion that the merger is in the public interest." The Commission has now reconsidered that order and compromised one of the benefits. Having done so, I believe the Commission was obligated to go on and to reconsider whether the benefits of the merger are still as great as the costs. By waiving condition 16 as to this deferral without considering the role condition 16 played in the overall approval of the merger (indeed, without addressing whether the merger is still in the public interest with condition 16 so compromised), I believe that the Commission fails to comply with G.S. 62-80.

In conclusion, I object to the accounting policy, logic, and interpretation of law in this decision, and I respectfully dissent.

\s\ Jo Anne Sanford
Chairman Jo Anne Sanford

DOCKET NO. E-2, SUB 769

COMMISSIONER ERVIN, DISSENTING:

I respectfully dissent from the Commission's decision to grant CP&L's request to defer certain emission allowance costs for disposition in a future proceeding. I dissent from the Commission's decision because I do not believe that CP&L has justified such a significant alteration of the provisions of our order approving the merger between CP&L and NCNG, because I am concerned that the Commission has failed to follow the procedures which ought to be employed in connection with the reconsideration of prior Commission orders, and because I do not believe that there is adequate justification for deferring the emission allowance costs at issue here.

As all parties acknowledge, the relief which CP&L has requested in this proceeding is directly prohibited by Regulatory Condition No. 16 adopted in the Commission order approving the merger between CP&L and NCNG. Although much of the opposition to CP&L's proposed accounting treatment for these emission allowance costs rests on the contention that "a deal is a deal" and that CP&L's proposal violates the terms of the settlement agreement between the Company and the Public Staff in that case, I do not agree with the implicit contention that there is some sort of contractual barrier to a decision in CP&L's favor. Although the merger conditions approved in the Commission's order, including the one at issue here, had their origin in an agreement between CP&L and the Public Staff, those conditions, once approved by the Commission and incorporated in the Commission's decision, become a Commission order subject to the provisions of the Public Utilities Act rather than a set of contractually-based obligations subject to independent enforcement at the request of an affected party. As a result, I do not believe that the contention that "a deal is a deal" should determine the outcome of this proceeding.

I am equally unconvinced that the controversy over whether any party to this proceeding is obstinately refusing to accede to reasonable requests for a waiver of the conditions adopted in the CP&L-NCNG merger order is relevant to a proper resolution of this dispute. Although I expect all parties to Commission proceedings to act reasonably when confronted with a request for modification of a prior order, I also expect each party to adhere to principle where appropriate. Just as the Company had the right to seek relief from Regulatory Condition No. 16 in this proceeding, any other party has the right to seek the Commission's assistance in resolving other disputes over the proper application of the conditions adopted by the Commission in that order. As a result, the controversy over the desirability of strictly enforcing other merger conditions at other times is simply not relevant to the matter at issue here.

A number of parties have expressed concern that any particular outcome in this proceeding could have an adverse impact upon the future of the settlement process in other cases. I do not believe that this issue is germane to the ultimate decision which the Commission must make in this proceeding either. The stipulation process is not an end in itself; instead, it is a means to the end of obtaining a fair and reasonable resolution of matters brought before the Commission for decision. Such stipulations are not, under well-established North Carolina law, binding upon the Commission. On the contrary, the Commission remains ultimately responsible for the proper resolution of matters within its regulatory jurisdiction. As a result, the existence of a stipulation is simply a factor which the Commission must consider in deciding a particular proceeding. State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 351 N.C. 223, 524 S.E.2d 10 (2000); State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 348 N.C. 452, 466, 500 S.E.2d 693 (1998). The Commission should be more concerned with deciding cases in an appropriate manner than it is with whether its decisions do or do not foster future settlement agreements in other cases. As a result, the impact of the Commission's decision upon the settlement process should not be determinative of the ultimate outcome in this proceeding.

The initial issue which the Commission must address in this proceedings is the scope of our authority to grant the requested waiver of Regulatory Condition No. 16 as applied to these emission allowance costs and the criteria which should be utilized in examining this issue. At the oral argument held in this proceeding on January 2, 2000, CP&L suggested that the Commission's authority to grant the requested waiver might stem from G.S. 62-80, which provides that "[t]he Commission may at any time upon notice to the public utility and to the other parties of record affected, and after opportunity to be heard as provided in the case of complaints, rescind, alter or amend any order or decision made by it." Although earlier decisions suggested that the Commission was not entitled to reconsider a prior order in the absence of changed circumstances, State ex rel. Utilities Commission v. Carolina Coach Company, 260 N.C. 43, 132 S.E.2d 249 (1963), more recent decisions indicate that the Commission's reconsideration authority is not so sharply circumscribed. On the contrary, "G.S. 62-80 is broad enough to permit the Commission to modify and amend its order, even if 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." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 575, 584, 232 S.E.2d 177 (1977). For example, "nothing in G.S. 62-80 . . . prevents the Commission from concluding on reconsideration that its original lack of enthusiasm for the testimony of [a particular] witness was ill-founded." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 575, 584, 232 S.E.2d 177 (1977). As a result, the extent to which the Commission should reconsider a prior order under G. S. 62-80 is a discretionary matter which the Commission must determine in light of all relevant facts and circumstances. State ex rel. Utilities Commission v. MCI Telecommunications Corporation, 132 N.C. App. 625, 514 S.E.2d 276 (1999); State ex rel. Utilities Commission v. Services Unlimited, Inc., 9 N.C. App. 590, 176 S.E.2d 870 (1970).

The majority does not expressly state the legal basis upon which it relies in granting CP&L's request for a waiver of Regulatory Condition No. 16 except to quote from portions of the order approving the CP&L-NCNG merger. Among other things, the Commission stated in that order that, "[t]o the extent unforeseen or unintended issues arise, any interested party may bring them to the attention of the Commission, and the Commission has the authority to take action" and that "[i]f additional refinements to [the Code of Conduct and the Regulatory Conditions] are needed to address unforeseen or unintended events, CP&L and NCNG acknowledge that the Commission has the authority to make such refinements." In re Application to Engage in a Business Combination Transaction, Docket Nos. E-2, Sub 740, and G-21, Sub 377, Eighty-Ninth Report of the North Carolina Utilities Commission: Orders and Decisions 274, 289, 290 (2000). The majority does not indicate whether it believes that this language provides the Commission with independent authorization to reconsider the application of Regulatory Condition No. 16 to these emission allowance costs or whether it believes that this language merely constitutes recognition of the Commission's reconsideration authority under G.S. 62-80. As a result of the fact that the majority evidently believes that any independent reconsideration authority available to the Commission pursuant to the CP&L-NCNG merger order involves the exercise of informed discretion and the fact that the Commission's reconsideration authority under G.S. 62-80 is clearly discretionary in nature, I do not believe that there is any need to definitively resolve this issue since the appropriate inquiry under either approach should be essentially the same.

The discretionary nature of the Commission's reconsideration authority under either approach described above does not, at least in my opinion, give the Commission unfettered freedom to rescind, alter, or amend a prior order without adequate justification. All Commission decisions should be made after careful consideration of the applicable law, the record evidence, and the arguments of the parties. G.S. 62-65; G.S. 62-78; G.S. 62-79. This fact suggests, in turn, that Commission decisions should be treated as presumptively valid when they are challenged at a later time, although I would be the first to agree that any Commission decision which is no longer reflective of sound public policy should be changed to the extent authorized by the Public Utilities Act. As a result, the Commission should carefully weigh the cogency of the arguments advanced in support of and in opposition to CP&L's request to revisit Regulatory Condition No. 16 with respect to the emission allowance costs at issue here, placing the burden of proof upon CP&L as the party requesting modification of the status quo.

The essential argument advanced by CP&L in support of its request for reconsideration of Regulatory Condition No. 16 as applied to these emission allowance costs is the claim that unanticipated increases in fuel expense led the Company to forgo attempting to recoup these costs through the fuel adjustment process, necessitating resort to another avenue for the collection of these costs. The Commission accepts this line of argument by concluding "that the requested waiver of Regulatory Condition No. 16 is consistent with the public interest." As a result, the Company essentially makes a "changed circumstances" argument as justification for its request that the Commission reconsider its decision to enforce Regulatory Condition No. 16 as applied to the facts at issue here. I do not find CP&L's "changed circumstances" argument persuasive.

The emission allowances at issue here were purchased by CP&L beginning in 1993. Although the Company obtained permission from the Commission to accumulate carrying costs on these emission allowance costs from the time of their purchase until December 31, 1999, it did not seek authority to defer these costs after that date until several months after it began to use these allowances to assure compliance with the requirements of the Clean Air Act on January 1, 2000. The existence and magnitude of these emission allowance costs were apparent to CP&L at the time that the Commission approved Regulatory Condition No. 16; even so, the Company did not oppose the imposition of a merger condition which precluded the deferral of these costs. The volatility of electric utility fuel costs is not a new problem; instead, the volatility of fuel costs is the principal justification for the various fuel adjustment mechanisms which have been available to North Carolina electric utilities for several decades. State ex rel. Utilities Commission v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976). CP&L could hardly have avoided being aware of the risk that rapidly escalating fuel costs might threaten the viability of its apparent strategy to attempt to recover these emission allowance expenses through the fuel adjustment mechanism. Moreover, CP&L has admitted that its failure to recoup these emission allowance costs through the fuel adjustment mechanism was a strategic decision rather than the result of some external obstacle to the achievement of its original goal. As a result, I do not believe that CP&L has provided adequate justification for revisiting and changing the result reached with respect to cost deferral issues in the order approving the merger between CP&L and NCNG.

I also question whether the Commission's decision to revisit the appropriateness of Regulatory Condition No. 16 as applied to these emission allowance costs is consistent with the procedural requirements of G.S. 62-80, to the extent that they apply in this instance, or with principles of fundamental procedural fairness. Although reconsideration of a prior order under G.S. 62-80 does not require the Commission to revisit all issues which were under consideration at the time of its original decision, State ex rel. Utilities Commission v. Public Service Company of North Carolina, Inc., 59 N.C. App. 448, 297 S.E.2d 119 (1982), it does require "notice to the public utility and to the other parties of record affected" and provision of an "opportunity to be heard as provided in the case of complaints." I believe that fundamental fairness requires that interested parties be given notice and an opportunity to be heard even if this proceeding is not explicitly governed by G.S. 62-80. An examination of the record indicates that a number of the parties to the CP&L-NCNG merger proceeding, including the North Carolina Eastern Municipal Power Agency, Transcontinental Gas Pipeline Corporation, Southeastern Gas & Power, Inc., and the Greenville Utilities Commission and the Cities of Monroe, Rocky Mount, and Wilson, were apparently never served with a copy of CP&L's request for relief from Regulatory Condition No. 16 or provided with an opportunity to be heard. As a result, I believe that the Commission's decision to approve CP&L's request may be procedurally defective as well.

Assuming for purposes of discussion that reconsideration is appropriate and that we reach the merits of CP&L's proposal, I would vote to disapprove the Company's request to defer these emission allowance costs. The essential argument advanced by CP&L is that the purchase of emission allowances represents an important component of the Company's strategy for complying with the provisions of the 1990 amendments to the Clean Air Act, that CP&L will not be able to recover these costs from ratepayers if the present proposal is rejected, and that approval of the present proposal is without prejudice to the Commission's ultimate authority to determine the appropriate ratemaking treatment of these costs at a later time. The Commission's statements that deferral of these emission allowance costs is appropriate because such accounting treatment would permit "the reasonableness of the costs in question and the appropriate overall regulatory treatment to be accorded to such costs [to] be fully examined in an appropriate forum," because "closing the door on CP&L at this juncture without affording the Company an opportunity to present evidence on this issue in a future proceeding would be fundamentally unfair to the Company," and because a Commission decision in CP&L's favor would not harm ratepayers "since such costs cannot be recovered in rates until such time as the Commission may determine in a future proceeding that they were just, reasonable, and prudently incurred" indicate that the majority has adopted the Company's logic. The arguments advanced by CP&L and accepted by the Commission cannot withstand close analysis when considered against the standards which should be utilized in determining the appropriateness of requests to defer utility operating expense amounts.

The Commission has not routinely approved deferred accounting treatment of utility expenses in the past. At the time that the Commission allowed PSNC to defer Year 2000 conversion costs, we stated that the Commission "rarely allows a utility to defer current expenses for future recovery;" that"[d]eferred accounting treatment is generally authorized only if the cost[] incurred is unusual and material and of such magnitude that departure from the Commission's more traditional practices is deemed to be warranted from the standpoint of fairness and equity to both consumers and shareholders;" that prior deferrals have involved "such events as severe storm damage (Hugo and Fran) and major repairs for Nantahala Power and Light and for current and future manufactured gas plant (MGP) clean-up costs;" and that, when the Commission has approved deferred accounting, it has generally required that the annual amortization of such costs begin in the period incurred rather than being held to a rate case before being amortized," with the exception of "the MGP costs for which the level of future costs is unknown." In re Request for Deferred Accounting Treatment, Docket No. G-5, Sub 369, Order Approving Deferred Accounting Treatment (1997). As a practical matter, the Commission has generally limited the availability of deferral accounting outside the context of a general rate case to expenses which are significant in amount; which either relate to a multi-year period or are incurred on a relatively infrequent basis; or which are unlikely to be recovered through existing rates. These criteria are simply not present here. Eg.: In re Motion of Gas Research Institute, Docket No. G-100, Sub 76, Order on Motion of Gas Research Institute (1999) (deferral allowed for voluntary contributions by local distribution companies to the Gas Research Institute previously recovered through the purchased gas adjustment process and not subject to future recovery in that manner due to a change in the underlying funding mechanism); In re Deferral Accounting Treatment of Investment in Natural Gas Expansion Projects, Docket

No. G-100, Sub 68, Order Adopting Rule R6-89 (1995) (deferral accounting approved for local distribution company investment in natural gas transmission lines intended to serve areas eligible for support from an expansion fund established pursuant to G.S. 62-158); In re Application for Approval of Deferred Accounting, Docket No. G-9, Sub 391, Order Approving Deferred Accounting Treatment (1997) (deferral accounting approved for Year 2000 compliance costs); In re Request for Deferred Accounting Treatment, Docket No. G-5, Sub 369, Order Approving Deferred Accounting Treatment (1997) (deferral allowed for "unusual" and "material" Year 2000 compliance costs); In re Request for Approval of Accounting for Storm Damage Costs, Docket No. E-7, Sub 460, Order Establishing Accounting Procedure (1990) (deferral allowed for costs associated with the repair of damage resulting from a May, 1989, tornado and Hurricane Hugo); In re Request for Approval of Accounting Treatment, Docket No. E-13, Sub 158 (1992) (deferral allowed for painting costs at various locations, additional repairs at the Franklin hydro plant, and contaminated soil cleanup at various substations and storage locations on the grounds that these expenditures are "extraordinary expenditures of such magnitude as to warrant deferral accounting treatment," "do not occur regularly," and "are of a nature similar to those for which the Commission has approved deferral accounting and amortization treatment in the past"); In re Request for Approval of Accounting Treatment, Docket No. E-13, Sub 136, Order Approving Accounting Treatment (1989) (deferral refused for concrete repair at the Bryson hydro dam, the replacement of insulation on the Franklin hydro generator, and the painting of the Queens Creek hydro pipeline because these expenditures "do not substantially increase the service benefits of the related assets" and were "not of such magnitude as to warrant deferral accounting treatment;" deferral allowed for rewinding the Nantahala generator and repairing the dam surface and spillway and replacing the sealgate on the tainter gate at the Franklin hydro plant since these expenditures would "substantially increase the future service potential of the related asset and increase its service life" and since "this accounting treatment is appropriate in order to achieve a proper matching of revenues and expenses over the periods benefitted by the expenditure"). As a result, deferral accounting should only be allowed in exceptional circumstances.

I am not satisfied that the emission allowance costs at issue here are sufficiently material to justify approval of CP&L's proposal. The emission allowances at issue here apparently total $45,000,000 over the next five years and include North Carolina retail amounts of $17,000,000 for 2000 and $13,000,000 for 2001. As estimated by our staff, these amounts constitute a relatively small percentage of CP&L's income available for common equity. A failure to defer these expenses on a ongoing basis will not in any way threaten CP&L's financial stability; counsel for CP&L conceded as much during oral argument. CP&L stated in its 1999 annual report that "[i]ncreased operation and maintenance costs, including emission allowance expenses, installation of additional equipment, and increased fuel costs are not expected to be material to the consolidated financial position or results of operations of the Company." As a result, I do not believe that these costs are of sufficient magnitude to justify approval of CP&L's request for deferral accounting.

The costs at issue here are not at all unusual or unexpected. Environmental legislation intended to foster cleaner air has been in force for several decades. Although the 1990 amendments to the Clean Air Act are of more recent vintage, CP&L has known of their existence for years and purchased the first of the emission allowances at issue here approximately eight years ago. CP&L's strategy for complying with environmental legislation undoubtedly resulted from careful consideration by the Company's management. As I result, I am not convinced that these emission allowance costs are sufficiently unusual and unexpected to justify their placement in a deferred account.

Finally, I do not believe that the costs at issue here have any sort of multi-period impact. The emission allowance expenses which are the subject of this dispute are clearly operating expenses rather than capital costs. These expenditures do not, as far as I have been able to ascertain, relate to the provision of service outside the year in which the related emission allowances are "cashed in." The fact that CP&L purchased these emission allowances in lieu of constructing scrubbers, which would clearly involve the incurrence of a capital cost, does not justify treating these expenditures as something other than what they are. The utility environment is replete with tradeoffs between operating expenses and capital costs; that fact does not justify treating an expense as a capital cost or vice versa. As a result, the costs at issue here do not appear to have the sort of multi-period impact which has traditionally justified the use of deferral accounting.

CP&L and the majority argue that a failure to allow deferred accounting treatment for these emission allowance costs will effectively preclude their recovery from ratepayers and argue that such a result is unfair. This argument overstates the extent to which CP&L is currently precluded from attempting to recover these emission allowance costs through the ordinary ratemaking process. CP&L claims that it intended to attempt to recoup these monies through the fuel adjustment process. As far as I am aware, nothing prevents CP&L from attempting to collect emission allowance expenditures incurred during future fuel adjustment test periods in exactly that way. The only emission allowance expenditures which CP&L is currently precluded from collecting through the fuel adjustment process are those which were incurred during the test periods utilized during prior fuel adjustment proceedings. As a result, the remedy adopted by the Commission in this instance goes well beyond that needed to preclude the result which the Commission seeks to avoid.

Furthermore, the argument advanced by CP&L and accepted by the majority strikes me as inconsistent with two fundamental ratemaking principles. First, this argument gives insufficient attention to the principle that rates should be set on the basis of aggregate expenses and capital costs examined on a collective basis. The Supreme Court of North Carolina has commented, for example, that "[a]djustments for post test period increases in certain categories of expense may well give a distorted picture of the need for revenue since post test period experience in other categories of expense is not known and the possibility of offsetting adjustments is not precluded." State ex rel. Utilities Commission v. Virginia Electric and Power Company, 285 N.C. 398, 417-418, 206 S.E.2d 283 (1974). Although the record clearly indicates that these emission allowances were not included in CP&L's cost of service at the time of the Company's last general rate case, that fact standing alone is insufficient to persuade me that these costs will not be recovered through CP&L's existing rates due to changes in other components of CP&L's cost of service, such as the expiration of the amortization of the abandonment costs associated with Harris Nos. 2, 3, and 4 and the completion of the amortization of the deferred costs associated with Harris No. 1. Furthermore, acceptance of this component of the Company's argument will force future ratepayers to pay rates resting upon costs incurred to provide service at earlier times. "Prospective ratemaking to recover unexpected past expense, or to refund expected past expense which did not materialize, is as improper as retroactive ratemaking." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 469, 232 S.E.2d 184 (1977). Although I am not prepared to conclude that allowing these costs into rates at some future time would be unlawful, I do believe that acceptance of CP&L's claim that a refusal to approve the present request for deferral of these costs would be unfair may conflict with certain fundamental precepts set out in the Public Utilities Act.

CP&L has argued and the Commission has concluded that approval of CP&L's request to defer these emission allowance costs would harm no one because the Commission would not determine the ratemaking treatment to be afforded to these costs until a later time. This argument strikes me as inconsistent with FAS 71, which is the pronouncement of the Financial Accounting Standards Board governing the creation of deferred accounts such as that proposed here. According to FAS 71, "[a]n enterprise shall capitalize all or part of an incurred cost that would otherwise be charged to expense if" "[i]t is probable 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" and, "[b]ased on available evidence, future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs." The Basis For Conclusions appended to FAS 71 indicates that, "[u]nless an accounting order indicates the way a cost will be handled for ratemaking purposes, it causes no economic effects that would justify deviation from the generally accepted accounting principles generally applicable to business enterprises in general." According to FAS 71, the creation of a regulatory asset such as that proposed here does, in fact, amount to an implied promise on the part of the regulatory agency to allow rate recovery of these costs at some future time. In the absence of such an understanding, FAS 71 would not permit deferral of the amount in question. CP&L appeared to concede as much at oral argument when it contended that approval of its request would necessitate rate recovery in the absence of a showing of imprudence or some similar factor. As a result, I cannot help but conclude that the present order works a significant harm to CP&L's ratepayers by implicitly promising full rate recovery for these costs at a later time.

The Commission's decision further exacerbates this harm to CP&L's customers by omitting any reference to the amortization of these costs. A Commission decision approving the deferral of certain costs is ordinarily accompanied by a description of the manner in which those costs are to be amortized. In re Request for Deferred Accounting Treatment, Docket No. G-5, Sub 369, Order Approving Deferred Accounting Treatment (1997) ("when the Commission has approved deferred accounting, it has generally required that the annual amortization of such costs begin in the period incurred rather than being held to a rate case before being amortized," except in situations where the "level of future costs is unknown"). The Commission's decision completely omits any reference to this important issue, despite the fact that the relevant cost amount appears to be firmly established. As a result, the Commission's failure to require CP&L to begin amortizing these costs exacerbates the adverse impact of this decision on ratepayers by allowing the Company to retain the full amount of these costs in the newly-established deferred account until such time as the appropriate ratemaking treatment for these expenses is determined in a future proceeding.

The Commission's decision also harms CP&L's ratepayers by undoing a benefit received by the using and consuming public in return for approval of the merger between CP&L and NCNG. The proposed merger of CP&L and NCNG raised significant public interest concerns which were addressed during the Commission's consideration of the proposed merger. The Commission's order, which approved the proposed merger subject to a number of regulatory conditions, was clearly intended to structure the proposed transaction in such a way that the benefits to the using and consuming public at least equaled the potential harms. In re Application to Engage in Business Combination Transaction, Docket No. E-2, Sub 740, and G-21, Sub 377, <u>Eighty-Ninth Report of the North Carolina Utilities Commission: Orders and Decisions</u> 274, 280 (1999) ("the known, expected and potential benefits of the merger to the State of North Carolina and particularly to NCNG's and

CP&L's customers are at least as great as the known, expected and potential costs and risks"). As part of the process of ensuring that the benefits of the merger to customers were "at least as great" as the "costs and risks," the Commission approved merger conditions which prohibited CP&L from either increasing rates in the near term or deferring current costs for recovery in a future period. By negating this protection in accordance with CP&L's request, the Commission has subjected CP&L's electric ratepayers to a greater risk of increased future rates, fundamentally altering the balance between benefits and risks upon which the Commission's merger order was based. As a result, the Commission's decision harms CP&L's ratepayers by altering the cost/benefit balance utilized to justify approval of the merger between CP&L and NCNG in what I believe to be an uneven way.

The Commission's decision creates a risk that CP&L's customers will be subjected to future harm in another way as well. As all observers of the regulatory scene in North Carolina are aware, the General Assembly is currently studying the extent to which electric restructuring should be implemented in our State. Assuming for purposes of discussion that restructuring is determined to be in the public interest at some point in the future, the issue of the extent to which incumbent utilities will be allowed to recover stranded costs will necessarily arise. CP&L conceded during oral argument that creation of the proposed deferred account would add to the Company's potentially stranded costs. As a result, the Commission's decision plainly harms CP&L's customers by subjecting them to a risk of higher stranded costs in the event that the General Assembly decides to restructure the electric utility industry.

Another argument advanced by CP&L and adopted by the Commission is the claim that creation of the proposed deferred account would be consistent with the Commission's earlier decision in Docket Nos. E-100, Sub 70, and E-7, Sub 524, which allowed North Carolina's major electric utilities to accrue a carrying cost on inventoried emission allowances until December 31, 1999. I do not agree with this contention. Although the Commission's decision in that proceeding expressly reserved the right to evaluate the reasonableness of electric utility emission allowance expenditures and the long-term ratemaking treatment which should be afforded to such costs until a later time, nothing in that order authorized the deferral of emission allowance expenditures beyond the time that they began to be used to ensure utility compliance with federal environmental regulations, at which point those costs would have ordinarily been expensed. As a result, I do not believe that a failure to grant the relief requested by CP&L in this proceeding would be in any way inconsistent with our decision in Docket Nos. E-100, Sub 70 and E-7, Sub 524.

I finally question whether the import of the Commission's comments concerning CP&L's future environmental compliance strategy is consistent with the result reached in this proceeding. Assuming for purposes of discussion that the Commission wishes to encourage the Company to focus on the installation of pollution abatement equipment in lieu of purchasing emission allowances, the issuance of the present order will not, at least in my opinion, contribute to the achievement of that goal. Allowing the Company to defer these emission allowance costs will not discourage their future use and could have the opposite effect. I do not, at this point, know what environmental compliance strategy CP&L should utilize in the future and question whether this order is the appropriate forum for addressing that issue. At an absolute minimum, however, the result reached in this order is inconsistent with any effort to encourage the Company to move away from an environmental compliance strategy which places extensive reliance upon the purchase of emission allowances.

The effect of the Commission's order is to give new life to CP&L's efforts to collect emission allowance costs which were known to exist at the time of the CP&L-NCNG merger and which might not be recoverable in rates in the absence of the Commission's decision. The Commission has reached this decision without stating an adequate justification for revisiting the result reached in the order approving the merger between CP&L and NCNG or ensuring that all parties to the CP&L-NCNG merger proceeding have had an opportunity to be heard. The Commission's decision allows the creation of a deferred account for these emission allowance costs when I believe such an accounting treatment to be inappropriate. The Commission's decision exposes CP&L's ratepayers to a significant risk of future economic harm without providing any offsetting customer benefits. As a result of my strong disagreement with the result reached by the Commission in this instance, I respectfully dissent from the Commission's decision.

\s\ Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

DOCKET NO. E-2, SUB 784

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Carolina Power & Light Company) ORDER APPROVING
for Authority to Adjust Its Electric Rates and) FUEL CHARGE
Charges Pursuant to G.S. 621-133.2 and) ADJUSTMENT
NCUC Rule R8-55)

HEARD: Tuesday, August 7, 2001, at 10:00 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; and Commissioners James Y. Kerr, II and Robert V. Owens, Jr.

APPEARANCES:

For the Applicant:

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

For the Public Staff:

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

For the Carolina Utility Customers Association, Inc. (CUCA):

James P. West, Esq., West Law Office, P.C., Suite 1735, Two Hannover Square, 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

For the Attorney General

Leonard G. Green, Assistant Attorney General, NC Department of Justice
PO Box 629, Raleigh, North Carolina 27602-0629
For the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II)

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

BY THE COMMISSION: Pursuant to G.S. 62-133.2 and Commission Rule R8-55(e), Carolina Power & Light Company (CP&L 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, 2001, CP&L filed its

Application along with the testimony and exhibits of Company witness Ronald R. Penny. In its Application, the Company requested an increment of 0.039 cents/kWh (0.040 cents/kWh including gross receipts tax) to the base factor of 1.276 cents/kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537, or a recommended fuel factor of 1.315 cents/kWh. The Company also requested an increment of 0.214 cents/kWh (0.221 cents/kWh including gross receipts tax) for the Experience Modification Factor (EMF) to collect approximately $74.1 million of under-recovered fuel expense. CP&L noted that $13.2 million of the under-recovery is the amount agreed to pursuant to a settlement agreement approved by the Commission in CP&L's last fuel case, Docket No. E-2, Sub 765, that is eligible for recovery in this fuel case and $60.9 million of under-recovery occurred during the 12-month period April 1, 2000 to March 31, 2001. The Company proposed that the EMF rider be in effect for a fixed 12-month period.

On June 13, 2001, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony and Requiring Public Notice. The Commission scheduled the hearing for August 7, 2001.

On June 18, 2001, the Carolina Industrial Group for Fair Utility Rates II (CIGFUR II) filed a petition to intervene. On June 21, 2001, Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene in the proceeding. The Commission granted CUCA's and CIGFUR II's petitions by Order dated June 27, 2001.

The intervention of the Public Staff is noted pursuant to Commission Rule R1-19(e). On July 17, 2000, the Attorney General filed a Notice of Intervention pursuant to G.S. 62-20.

On July 20, 2001, the Company filed the affidavits of publication showing that public notice had been given as required by Rule R8-55(f) and the Commission's Order dated June 13, 2001.

On July 23, 2001, the Public Staff requested an extension of time to and including July 24, 2001, to file testimony. The Commission granted the Public Staff request on July 24, 2001.

On July 24, 2001, the Public Staff filed affidavits and exhibits of Thomas S. Lam, Michael C. Maness and Mary Ellen Shearon. The filing was made in accordance with Commission Rule R8-55(h) which requires the filing of Public Staff and other intervenor testimony at least 15 days prior to the hearing date. No other parties filed testimony in this case.

On August 7, 2001, the Company, CIGFUR-II, CUCA and the Public Staff filed a Stipulation that resolved all issues between and among these parties.

The docket came on for hearing as ordered on August 7, 2001. At the beginning of the hearing, counsel for CP&L advised the Commission that CP&L, CIGFUR II, CUCA and the Public Staff (Parties) had agreed to a Stipulation regarding the fuel factor and Experience Modification Factor (EMF) in this case. The Attorney General was not a party to the Stipulation but did not object to the agreement. The parties also agreed that cross-examination of all witnesses would be waived and that the testimony and exhibits of witness Ronald R. Penny and the affidavits and exhibits of

Public Staff witnesses Thomas S. Lam, Michael C. Maness and Mary Ellen Shearon would be entered into the record. CP&L counsel discussed the details of the Stipulation with the Commission, which are discussed herein. The Commission requested the filing of Proposed Orders on or before August 27, 2001.

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 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. CP&L is engaged in the business of generating, transmitting, and selling electric power to the public in North Carolina. CP&L 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 March 31, 2001.

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

4. The performance of CP&L's nuclear units during the test period was reasonable and prudent.

5. The proper fuel factor for this proceeding is 1.315 cents/kWh.

6. The Stipulation agreed to by the Parties is reasonable and should be approved. Pursuant to this Stipulation, the appropriate amount of the Company's North Carolina test period jurisdictional fuel expense under-recovery is $55,550,000. CP&L should be allowed to transfer this amount to a deferred account to accrue interest at the rate of 7% per year compounded annually and to recover this amount over a five-year period through its annual fuel cost recovery proceedings.

7. CP&L should collect $13.2 million of prior fuel expense under-recovery in this case, which is one third of the amount deferred from the last fuel case, Docket No. E-2, Sub 765, and eligible for recovery in this case.

8. The appropriate EMF increment to use in this proceeding is 0.038 cents/kWh (0.039 cents/kWh including gross receipts tax).

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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 which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for a historical 12-month period. In Commission Rule R8-55(b), the Commission has prescribed the twelve months ending March 31 as the test period for CP&L. All pre-filed exhibits and direct testimony submitted by the Company in support of its Application utilized the twelve months ended March 31, 2001, 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, SEPA and 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, 2001.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding can be found in the Company's Application and the monthly fuel reports on file with the Commission. 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 procurement of coal, uranium and natural gas were filed in the Fuel Procurement Practices Report which was updated in March 2000. 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 762 for calendar year 2000 and in Docket No. E-2, Sub 779 for calendar year 2001. No party offered any testimony contesting the Company's fuel procurement and power purchasing practices.

The Commission finds and concludes that CP&L's fuel procurement procedures and power purchasing practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding can be found in the Company's Application and direct testimony and exhibits of CP&L witness Penny and the Affidavit of Public Staff witness Lam.

The Company files with this Commission monthly Fuel Reports pursuant to Rule R8-52 and Base Load Power Plant Performance Reports pursuant to Rule R8-53. These reports were filed in Docket No. E-2, Sub 762 for calendar year 2000 and Docket No. E-2, Sub 779 for calendar year 2001. Witness Penny testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55(i) based upon the test year actual nuclear capacity factor of 95.94% exceeding the NERC five-year average of 74.91%. The Company's Boiling Water Reactors (BWRs) at Brunswick Units 1 and 2 experienced capacity factors of 101.8% and 89.54% respectively. The Pressurized Water Reactor (PWRs) at Robinson and Harris experienced capacity factors of 102.55% and 91.12% respectively. Brunswick Unit 2 and Harris each experienced refueling outages during the test period. Public Staff witness Lam verified the Company's test year actual and the NERC average nuclear capacity factor calculations. No other party offered evidence on this issue.

Based on the evidence, the Commission finds and concludes that the operation of the Company's base load nuclear plants was reasonable and prudent during the test period. The Commission notes that the test period system nuclear capacity factor of 95.94% is the highest operation level achieved by CP&L's nuclear units since the fuel adjustment proceedings under G.S. 62-133.2 began in 1985.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting these findings can be found in the testimony and exhibits of Company witness Penny, the Affidavit of Public Staff witness Lam and the Stipulation agreed to by the Parties.

In Penny Exhibit No. 3, the Company calculated a fuel factor of 1.481 cents/kWh based on normalized capacity factors for its nuclear units in accordance with Commission Rule R8-55(c)(1) by using the five-year North American Electric Reliability Council (NERC) Equipment Availability Report 1995-1999 average for BWRs and PWRs. The workpapers included in Penny Exhibit No. 6 show kWh normalization for customer growth and weather at both meter and generation levels was performed in a manner consistent with 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 past cases. The NERC five-year capacity factors for Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 70.99% and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at 79.06%. The Company's NERC normalized calculations resulted in a system nuclear capacity factor of 74.91% using this data.

Witness Penny explained in his pre-filed testimony that he could not recommend the 1.481 cents/kWh fuel factor based on the NERC average capacity factors because the Company's nuclear units are expected to significantly outperform the NERC average during the period rates are in effect in this case. Therefore, as indicated in his testimony, Company witness Penny recommended adoption of a base fuel factor of 1.315 cents/kWh based on a projected nuclear capacity factor of 91.47% and expected cost data during the time period October 1, 2001 through September 30, 2002. This calculation is shown on Penny Exhibit No. 3A, which was included with his pre-filed testimony. The computation of the 1.315 cents/kWh fuel factor is summarized below:

Generation Type	MWhs	Fuel Cost
Nuclear	25,433,034	$117,576,916
Purchase — Cogen	1,421,700	20,392,000
Purchase — AEP	1,823,100	20,765,100
Purchase — Fay PWC	238,800	14,756,200
Purchase — SEPA	181,600	0
Purchase — Other	793,800	36,590,300
Hydro	761,800	0
Coal	32,218,600	555,971,700
IC	2,598,700	131,442,246
Sales	(4,000,000)	(142,552,300)
Total Adjusted	61,471,134	$754,942,162
Less NCEMPA		
PA Nuclear		$15,339,800
PA Coal		24,856,700
PA Buy-Back		(1,731,200)
System Projected Fuel Expense		$716,476,862
Projected kWh Meter Sales		54,492,329,000
Projected Fuel Factor (cents/kWh)		1.315

After review of the Company's fuel factor proposal, Public Staff witness Lam recommended that the Commission approve CP&L's requested base fuel factor of 1.315 cents/kWh. Mr. Lam stated in his Affidavit that a nuclear capacity factor of 91.47% was more representative of the operation of the Company's nuclear units during the time period when the fuel factor will be in effect than the NERC five-year average of 74.91% or the actual test year average capacity factor. No other party produced any evidence to challenge the Company's request in this case. Furthermore, the Stipulation agreed to by the Parties recommended the adoption of a base fuel factor of 1.315 cents/kWh.

Based on the Stipulation and evidence of record, the Commission finds and concludes that the proper fuel factor to adopt in this case is 1.315 cents/kWh based on a nuclear capacity factor of 91.47%. This factor is an increase of 0.039 cents/kWh (0.040 cents/kWh with gross receipts tax) from the base fuel factor of 1.276 cents/kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6, 7 AND 8

The evidence supporting these findings can be found in the testimony and exhibits of Company witness Penny, the Affidavits of Public Staff witnesses Maness and Shearon and the Stipulation agreed to by the Parties.

G.S. 62-133.2(d) provides:

"The Commission shall incorporate in its fuel cost determination under this subsection the experienced overrecovery or underrecovery 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 overrecovery or underrecovery 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 . . ."

The pre-filed direct testimony and exhibits submitted by Company witness Penny indicated that the Company under-collected fuel cost during the test period by $60,928,563 using the base fuel factors approved by the Commission in Docket No. E-2, Subs 748 and 765. The Company increased this amount by $13,220,355 to reflect one third of the under-recovered amount that was deferred from CP&L's last fuel case, Docket No. E-2, Sub 765. The Company proposed an EMF increment factor of 0.214 cents/kWh (0.221 cents/kWh with gross receipts tax) to recover the full $74.1 million under-recovered amount. However, witness Penny's pre-filed direct testimony indicated that CP&L was exploring alternatives to recover the $60.9 million amount.

As stated in their Affidavits, Public Staff witnesses Maness and Shearon reviewed the Company's fuel and purchased power expense records for the test period. Witness Maness in his Affidavit recommended that the Commission adopt the stipulation reached by the Public Staff, the Attorney General, CP&L, Duke Power Company, and North Carolina Power regarding the proper methodology for determining the fuel cost associated with power purchases from power marketers and other suppliers (the Marketer Stipulation) in this fuel case. The Marketer Stipulation was filed by CP&L with the Commission in Docket No. E-2, Sub 748 and is intended by the parties to be applicable to the 1999, 2000 and 2001 fuel cost proceedings. The Marketer Stipulation allows a utility to use 70% of the energy cost of a purchase as a proxy for the fuel cost component of power purchased from a power marketer when the fuel cost component is not known. The Stipulation also provides for an adjustment of the 70% ratio during the effective period if it is determined that fuel cost to total energy cost ratio for off-system sales falls outside the range of 63% to 77%. The 70% ratio was determined by an analysis of the fuel costs associated with CP&L's, Duke's and NC Power's off-system sales.

During the most recent Duke fuel case in Docket No. E-7, Sub 685, Public Staff witness Maness testified that the Public Staff had performed an analysis of off-system sales for the three utilities and determined that the fuel percentage had dropped below the 63% level. The Public Staff analysis indicated the fuel percentage ranged from 57.36% to 60.88% and the Public Staff was thus recommending a marketer percentage of 60%. The Commission adopted the 60% ratio in the Duke case. Witness Maness also recommended the 60% ratio for use in this fuel case. Mr. Maness noted that CP&L had already reflected the 60% marketer ratio in derivation of the $60.9 million test period under-recovery.

The Commission notes that recovery of fuel cost from 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 that the methodology for determining the fuel cost component of purchases from power marketers and other suppliers as set forth in the Marketer Stipulation is reasonable and will be accepted for purposes of this proceeding. The Commission also accepts the use of a 60% marketer percentage in this proceeding as recommended by Public Staff witness Maness and adopted by CP&L. No party submitted evidence in this proceeding to suggest that the Commission's reliance on the Marketer Stipulation for purposes of this proceeding would be unreasonable.

Public Staff witnesses Maness and Shearon reviewed the Company's purchased power records during the test period. Witness Maness testified that the Company had followed the Marketer Stipulation agreement. Witness Maness noted that CP&L received actual purchase fuel cost from several sellers after the close of the test period and the adjusted test period expenses to reflect this actual cost. Witness Maness calculated the test period under-recovery should be reduced by $5,298,000 to reflect the actual fuel cost of these purchases. This reduction lowered CP&L's test year under-recovery to $55,630,563. The Company did not challenge this adjustment.

At the beginning of the hearing in this proceeding, CP&L presented the Stipulation agreed to by the Parties, which was filed with the Chief Clerk just prior to the start of the hearing. The Stipulation provides that CP&L will include an EMF increment of 0.038 cents/kWh (0.039 cents/kWh with gross receipts tax) in rates in this case to recover $13.2 million of under-recovered fuel cost. This amount of under-recovery is one third of the amount that the Commission found in CP&L's last rate case, Docket No. E-2, Sub 765, to be recovered in this case and is shown on Penny Exhibit No. 4. This factor is determined by dividing the $13,220,355 deferred amount by test period normalized MWh sales of 34,620,508.

The Stipulation also indicates that the test period under-recovery should be adjusted to $55,550,000. The Stipulation further provides that the $55.55 million should be transferred to a separate deferred account and that CP&L should be allowed to recover the $55.55 million of under-recovered fuel cost over the next five fuel proceedings in accordance with the terms and conditions of the Stipulation. The Stipulation further provided that with the exception of the fuel costs incurred by CP&L associated with its purchases of electricity from Broad River Energy, LLC, all of the

$55,550,000 in under-recovered fuel costs are conclusively deemed just and reasonable and prudently incurred and may not be challenged by any party to this Stipulation in any future proceeding.

Based upon the evidence of record and the Stipulation, which is incorporated herein by reference and made a part hereof, the Commission hereby accepts the $55.55 million of under-recovered fuel expense as the proper amount of test period under-recovery as indicated in the Stipulation and finds that all of these costs, with the exception of the fuel costs incurred by CP&L associated with its purchases of electricity from Broad River Energy, LLC which any party may challenge in CP&L's next fuel case, are just and reasonable and were prudently incurred and are a proper expense for inclusion in a deferred account. Therefore, CP&L will be allowed to transfer this amount to a deferred account. The Stipulation also provides for accruing of interest on the under-recovered balance beginning October 1, 2001. For interest calculation purposes, the under-recovered balance will be stated net of income tax savings. The Commission will allow interest to accrue on the net of tax balance at the prescribed rate of 7% compounded annually as prescribed by the Stipulation. CP&L shall be allowed to recover the unrecovered fuel and interest costs in subsequent fuel cost recovery proceedings over the next five years, provided that no more than $21 million of these costs may be recovered in any single year during the next five annual fuel cost recovery proceedings. CP&L shall be allowed to write-off any or all of the unrecovered balance, in its discretion, in such account at any time. Any unrecovered balance at the end of the five-year period shall be written off.

Therefore, the Commission finds and concludes that the Stipulation agreement entered into by and between CP&L, CIGFUR II, CUCA and the Public Staff should be approved in this case. It is appropriate for CP&L to recover $13.2 million in under-recovered fuel cost with an EMF increment of 0.038 cents/kWh (0.039 cents/kWh with gross receipts tax) over the 12-month period beginning October 1, 2001. CP&L will be allowed to defer recovery of $55.55 million of un-recovered fuel cost over the next five fuel proceedings in accordance with the terms and conditions of the Stipulation as discussed herein.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after October 1, 2001, CP&L shall adjust the base fuel component in its North Carolina retail rates by an increment of 0.039 cents/kWh (0.040 cents/kWh including gross receipts tax) above the base fuel component approved in Docket No. E-2, Sub 537. Said increment shall remain in effect until changed by a subsequent Order of this Commission in a general rate case or fuel case.

2. That CP&L shall establish an EMF Rider as described herein to reflect an increment of 0.038 cents/kWh (0.039 cents/kWh including gross receipts tax) for retail rate schedules and applicable riders. This Rider is to remain in effect for a 12-month period beginning October 1, 2001 and expiring September 30, 2002.

3. That the Stipulation entered into by CP&L, the Public Staff, CUCA and CIGFUR-II is approved in its entirety, and CP&L shall be allowed to defer recovery of $55.55 million of test period un-recovered fuel cost over the next five fuel proceedings in accordance with the terms and conditions of the Stipulation.

4. That CP&L 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.

5. That CP&L 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.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of September, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

je091201.01

APPENDIX A

CP&L BILL MESSAGE

The North Carolina Utilities Commission issued an Order on September __, 2001, after public hearings and review, approving a fuel charge increase of approximately $55.4 million in the rates and charges paid by North Carolina retail customers of CP&L. The rate increase will be effective for service rendered on and after October 1, 2001, and will result in a monthly net rate increase of $1.60 for a typical customer using 1,000 kWh per month.

DOCKET NO. E-7, SUB 685

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation Pursuant	)	ORDER APPROVING
to G. S. 62-133.2 and NCUC Rule R8-55 Relating	)	FUEL CHARGE
to Fuel Charge Adjustments for Electric Utilities	)	ADJUSTMENT

HEARD: Tuesday, May 1, 2001, at 10:00 a.m. and on Wednesday, May 9, 2001, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin IV, Presiding; Commissioner J. Richard Conder; and Commissioner Lorinzo Joyner

APPEARANCES:

For Duke Power, a division of Duke Energy Corporation:

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

and

Lara S. Nichols, Senior Counsel, Duke Energy Corporation, 422 South Church Street, Charlotte, North Carolina 28202

For the Public Staff:

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

For the Attorney General:

Len Green, Associate Attorney General, N.C. Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629

For Carolina Utility Customers Association, Inc.:

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

For Carolina Industrial Groups for Fair Utility Rates I and II:

Ralph McDonald, Bailey & Dixon, L.L.P., Post Office Box 1351, Raleigh, North Carolina 27002-1351

BY THE COMMISSION: On March 2, 2001, Duke Power, a division of Duke Energy Corporation (Duke Power 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 7, 2001, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Discovery Guidelines and Requiring Public Notice.

On March 15, 2001, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene. Carolina Industrial Groups for Fair Utility Rates I and II (CIGFUR) filed its Protest and Petition to Intervene on March 30, 2001. The petitions of CUCA and CIGFUR were allowed by Commission Orders issued on March 19, 2001, and April 3, 2001, respectively. The Attorney General gave Notice of Intervention pursuant to G.S. 62-20 on March 28, 2001. The intervention of the Public Staff is noted pursuant to Commission Rule R1-19(e).

On March 21, 2001, CUCA filed a Motion to Modify the Scheduling Order. This motion was allowed by Commission Order issued on March 27, 2001.

On April 18, 2001, the Public Staff filed the direct testimony and exhibits of Michael C. Maness and affidavits of Thomas S. Lam and Mary Ellen Shearon. CUCA filed the testimony of Kevin W. O'Donnell.

On April 23, 2001, CUCA filed a Motion for Continuance of the Evidentiary Hearing, which had been originally scheduled for May 1, 2001. The motion was granted by Order dated April 25, 2001, and the originally scheduled hearing was held for the taking of testimony from public witnesses only. No public witnesses appeared at this hearing.

On May 2, 2001, Duke Power filed the rebuttal testimony of Steven K. Young.

The evidentiary hearing was held on May 9, 2001, at the time and place shown above. Duke Power presented the direct and rebuttal testimony of Steven K. Young, Vice President, Rates and Regulatory Affairs. The Public Staff presented the testimony of Michael C. Maness, Supervisor, Electric Section, Accounting Division, and the affidavits of Thomas S. Lam, Engineer, Electric Division, and Mary Ellen Shearon, Accountant, Accounting Division. CUCA presented the testimony of Kevin W. O'Donnell, President of Nova Energy Consultants, Inc. 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 1, 2001, as allowed by the Commission. CUCA filed a Response to Duke's brief on June 8, 2001. Duke filed a letter objecting to consideration of this Response since the Commission had not called for reply briefs. The Commission sustains this objection and strikes CUCA's Response.

Based on the Company's verified Application, the testimony and exhibits received into evidence at the hearing, and the entire record in this matter, the Commission makes the following

FINDINGS OF FACT

1. Duke Energy Corporation is a duly organized corporation existing under the laws of the State of North Carolina. Duke Power, a division of Duke Energy Corporation, 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 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 December 31, 2000.

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

4. The test period per book system sales are 78,589,678 MWH.

5. The test period per book system generation is 89,860,974 MWH and is categorized as follows:

Generation Type	MWH
Coal	43,525,979
Oil and Gas	459,564
Light Off	-
Nuclear	41,072,729
Hydro	929,181
Net Pumped Storage	(773,269)
Purchased Power	3,122,936
Catawba Contract Purchases	149,883
Catawba Interconnection Agreements	1,103,462
Interchange	270,509
	89,860,974

6. The nuclear capacity factor that is appropriate for use in this proceeding is 85%.

7. The adjusted test period system sales for use in this proceeding are 78,797,963 MWH.

8. The adjusted test period system generation for use in this proceeding is 89,618,136 MWH and is categorized as follows:

Generation Type	MWH
Coal	47,466,240
Oil and Gas	560,886
Light Off	-
Nuclear	37,380,782
Hydro	1,820,600
Net Pumped Storage	(733,308)
Purchased Power	3,122,936
	89,618,136

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

A. The coal fuel price is $13.50/MWH.
B. The oil and gas fuel price is $62.00/MWH.
C. The appropriate Light Off fuel expense is $5,700,000.
D. The nuclear fuel price is $4.19/MWH.
E. The purchased power fuel price is $19.90/MWH.
F. The Catawba Contract Purchase fuel price is $4.18/ MWH.

10. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 60% of the energy portion of the purchase price is reasonable for use in this proceeding.

11. Expenses related to emission allowances pursuant to Title IV of the Clean Air Act Amendments of 1990 are not fuel costs and should not be included in test period fuel expenses for purposes of this proceeding.

12. The adjusted test period system fuel expense for use in this proceeding is $807,624,000.

13. The proper fuel factor for this proceeding is 1.0249¢/kWh, excluding gross receipts tax.

14. The Company's North Carolina test period jurisdictional fuel expense over-collection is $16,608,000. The pro forma North Carolina jurisdictional sales are 52,575,121 MWH.

15. The Company's Experience Modification Factor (EMF) is a decrement of .0316¢/kWh, excluding gross receipts tax.

16. Interest expenses associated with the over-collection of test period fuel revenues amount to $2,491,000, based on a 10% annual interest rate.

17. The EMF interest decrement is .0047¢/kWh, excluding gross receipts tax.

18. The final fuel factor is .9886¢/kWh, excluding gross receipts tax.

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. In Rule R8-55(b), the Commission has prescribed the 12 months ending December 31 as the test period for Duke Power. The Company's filing was based on the 12 months ended December 31, 2000.

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 47, in July 1994, and were in effect throughout the 12 months ended December 31, 2000. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

No party offered testimony contesting 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 witness Young and the affidavit of Public Staff witness Lam.

Witness Young testified that the test period per book system sales were 78,589,678 MWH and test period per book system generation was 89,860,974 MWH. The test period per book system generation is categorized as follows:

Generation Type	MWH
Coal	43,525,979
Oil and Gas	459,564
Light Off	-
Nuclear	41,072,729
Hydro	929,181
Net Pumped Storage	(773,269)
Purchased Power	3,122,936
Catawba Contract Purchases	149,883
Catawba Interconnection Agreements	1,103,462
Interchange	270,509
	89,860,974

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 facilities and any unusual events.

Witness Young testified that Duke Power achieved a system nuclear capacity factor of 92.33% for the test period and that the most recent (1995-1999) NERC five-year average nuclear capacity factor for all pressurized water reactor units is 79.06%. The Company voluntarily proposed the use of an 85% system nuclear capacity factor to determine the fuel factor in this proceeding as is reflected in witness Young's testimony and exhibits. Public Staff witness Lam supported the use of the 85% nuclear capacity factor proposed by the Company. No party elicited testimony contesting the use of a nuclear capacity factor of 85% in this proceeding. The 85% nuclear capacity factor proposed by the Company and agreed to by the Public Staff constitutes a factor significantly higher than the applicable NERC five-year average capacity factor of 79.06% which provides the basis for the normalized capacity factor pursuant to Commission Rule R8-55(c)(1).

Based upon the agreement of the Company and the Public Staff as to the appropriate levels of per book MWH generation and sales, and noting the absence of evidence presented to the contrary, the Commission concludes that the levels of per book sales of 78,589,678 MWH and of per book generation of 89,860,974 MWH are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 85% nuclear capacity factor and its associated generation of 37,380,782 MWH are reasonable and appropriate for determining the appropriate fuel costs in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 AND 8

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

Witness Young made an adjustment of a positive 208,285 MWH and a negative 242,838 MWH to per book sales and per books generation, respectively, for adjustments relating to weather normalization, customer growth, the Catawba retained generation adjustment and the line loss/Company use adjustment, based on an 85% normalized system nuclear capacity factor. He therefore calculated an adjusted sales level of 78,797,963 MWH and an adjusted generation level of 89,618,136 MWH.

Witness Lam reviewed and accepted witness Young's adjusted generation level of 89,618,136 MWH and sales level of 78,797,963 MWH. No party contested the Company's adjustments for weather normalization, customer growth, Catawba retained generation, or line losses/Company use.

The Commission concludes, after finding a system nuclear capacity factor of 85% reasonable and appropriate in Finding of Fact No. 6, that the adjustment to per book system generation of a negative 242,838 MWH and the resulting adjusted test period generation level of 89,618,136 MWH are both reasonable and appropriate for use in this proceeding. Total generation is categorized as follows:

Generation Type	MWH
Coal	47,466,240
Oil and Gas	560,886
Light Off	-
Nuclear	37,380,782
Hydro	1,820,600
Net Pumped Storage	(733,308)
Purchased Power	3,122,936
Catawba Contract Purchases	
	89,618,136

The Commission also finds the adjusted sales level of 78,797,963 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 contained in the testimony of Company witness Young and the affidavit of Public Staff witness Lam.

Witness Young recommended fuel prices as follows: (1) coal price of $13.50/MWH; (2) oil and gas price of $62.00/MWH; (3) light off fuel expense of $5,700,000; (4) nuclear fuel price of $4.19/MWH; (5) purchased power fuel price of $19.90/MWH; and (6) Catawba contract purchase fuel price of $4.18/MWH.

Based upon the agreement between the Company and the Public Staff as to the appropriate prices, the evidence in the record, and the absence of evidence to the contrary, the Commission concludes that these prices are reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the testimony of Public Staff witness Maness and Company witness Young.

Witness Maness testified that during the test year Duke Power purchased power from a large number of power marketers and other suppliers that did not provide it with the actual fuel costs associated with those purchases. To address this situation, Maness recommended that the Commission adopt the Stipulation reached by the Public Staff, the Attorney General, Duke Power, CP&L, and NC Power regarding the proper methodology for determining the fuel costs associated with purchases from power marketers and other suppliers. CP&L filed the Stipulation with the

Commission on June 4, 1999, in Docket No E-2, Sub 748. The Stipulation, which was filed as Maness Exhibit I in this proceeding, is intended by the parties to be applicable to the 1999, 2000, and 2001 fuel cost proceedings. The Stipulation generally provides that for purchases from power marketers, the utility shall assume that the fuel cost component of the purchase equals 70% of the energy portion of the purchase price. For purchases from other sellers that do not provide actual costs, the fuel cost component shall be determined using an appropriate ratio.

Witness Maness testified that 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." As a result of this Order, the Public Staff, Duke, CP&L, NC Power, and the Attorney General entered into a stipulation in 1997 regarding the proper methodology for determining the fuel cost associated with power purchased from power marketers and other suppliers. The methodology adopted by the parties used the three utilities' own off-system sales as the basis for determining a proxy for the fuel costs associated with applicable purchases. This methodology was accepted as reasonable by the Commission in each of the utilities' fuel proceedings in 1997 and 1998.

Witness Maness testified that upon the expiration of the 1997-1998 stipulation, the Public Staff analyzed the fuel component of the utilities' off-system sales set forth in the Monthly Fuel Reports for the twelve months ended October 31, 1998. This analysis, which was similar to that performed by the Public Staff in connection with the earlier stipulation, became the basis for the 70% ratio used in the 1999-2001 Stipulation. The methodology used for the 1999-2001 Stipulation (and thus the 70% ratio) has already been accepted by the Commission as reasonable in the 1999 CP&L and NC Power fuel proceedings, and in the 2000 Duke, CP&L, and NC Power fuel proceedings. Additionally, although the 1999-2001 Stipulation had not yet been finalized at the time of Duke's 1999 fuel proceeding, the underlying analysis was the basis for the Public Staff's recommendation, which was accepted by the Commission, that a 70% ratio be applied to the appropriate purchases in that case. Thus, in each fuel case since the beginning of 1997, the Commission has accepted as reasonable, under the criteria set forth in the 1996 Duke case, the use of the utilities' off-system sales to determine a fuel cost proxy for applicable purchases.

Witness Maness stated that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for the proxy fuel cost 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. Witness Maness also stated that 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 recommended that the Commission adopt the 1999-2001 Stipulation for purposes of this proceeding.

Witness Maness testified that included in the Stipulation is a provision which contemplates the possibility of an update to the 70% ratio during the effective period. The Stipulation states that "[t]he 70% ratio may be adjusted if a review of power sales reported to the Commission by the utilities during the most recent 12 months indicates that the total fuel cost to total energy cost ratio for such sales falls outside the range of 63% to 77%. If such ratio falls outside the range, the parties agree they will meet and negotiate the appropriate ratio."

Witness Maness testified that in order to determine if an update should be pursued, the Public Staff performed a review of the utilities' off-system sales set forth in the Monthly Fuel Reports, for the twelve months ended December 31, 2000. He stated that the Public Staff's analyses resulted in fuel percentages ranging from 57.36% to 60.88%, as set forth on Maness Exhibit II. Witness Maness stated that after reviewing all the data and calculations, the Public Staff concluded that they supported a finding that the off-system sales ratio has fallen below the lower end of the 63%-77% range and, therefore, that the ratio should be reduced for purposes of determining the Experience Modification Factor (EMF) in this proceeding to a level more consistent with the fuel percentage experienced with regard to off-system sales during 2000. Witness Maness recommended the use of a 60% ratio in this proceeding to determine the fuel costs of power purchases subject to the application of the off-system sales fuel percentage. He indicated that the use of this ratio results in reducing Duke's test year fuel costs for the purposes of calculating the EMF by $1,617,378, on a North Carolina retail basis.

Witness Maness testified that the result of the analyses had not been presented to CP&L or NC Power, but that regardless of the outcome of any negotiations with the utilities and the necessary subsequent Commission approval of any agreed-upon percentage, 60% is a reasonable ratio for use in this proceeding in view of the generally declining off-system sales fuel percentages.

Witness Young agreed with the Public Staff's recommendation to adjust Duke's filing to reflect treating 60% of energy charges associated with certain purchases as fuel expenses.

The Commission concludes, as it has in past cases, that the methodology underlying the Stipulation, 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 can be accepted under G.S. 62-133.2. As the Public Staff has testified, 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 ratio exhibited by the utilities' sales is similar to the ratio inherent in the sales made to Duke 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 Public Staff's testimony, 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 are subject to Commission review. Third, the methodology is supported by both the Public Staff and the Attorney General, on the one hand, and by the three utilities subject to the fuel clause statute, on the other, parties who represent different and sometimes adversarial interests. Finally, no party to this proceeding has elicited evidence of any alternative information available concerning the fuel cost component of purchases made from power marketers or other relevant sellers of power to Duke. Therefore, the Commission concludes that the methodology underlying the 1999-2001 Stipulation meets the criteria set forth in the 1996 Duke fuel case Order, and is reasonable for purposes of this proceeding as the method of determining the proxy fuel cost.

In reaching this conclusion, the Commission recognizes that the Stipulation was not signed by all parties to this proceeding. The Commission recognizes that such partial settlements of a case are not binding on the Commission and will be received into evidence and weighed along with the entire record. Moreover, non-signing parties may contest the terms of the Stipulation in each proceeding in which it is presented. However, the Commission notes that in this proceeding no party elicited evidence supporting any alternative methodology to the one that the Commission has accepted for several years. The Commission can find no good reason to depart from this approach to this issue in this proceeding. In addition, as recognized by the Commission in the past, use of the Stipulation resolves uncertainty Duke and other electric utilities would face regarding the future recovery of fuel costs associated with otherwise economical purchases from power marketers that lower overall costs.

Given the fact that the Commission has concluded that the methodology underlying the 1999-2001 Stipulation is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel ratio to be used in this case. The Stipulation states that, "[t]he 70% ratio may be adjusted if a review of power sales reported to the Commission by the utilities during the most recent 12 months indicates that the total fuel cost to total energy cost ratio for such sales falls outside the range of 63% to 77%. If such ratio falls outside this range, the parties agree they will meet and negotiate the appropriate ratio."

In making its determination on this matter, the Commission first notes that it believes that the general approach taken in the Stipulation of identifying a specific ratio to be used for a specific period of time, and then identifying a deadband around that ratio to control whether the ratio might be changed during that period, is reasonable. The Commission reaches this conclusion for two primary reasons. First, the fuel ratio is by nature a general estimate to be used to determine a proxy fuel cost; it is not a precise calculation of actual fuel costs. Second, under the terms of the Stipulation, the agreed-upon fuel ratio is only in effect for a limited period of time (three years). Given these facts, the Commission does not consider it necessary to change the fuel ratio determined according to the Stipulation each year during the three-year period for relatively minor changes. The Commission is of the opinion that the 63%-77% deadband set forth in the 1999-2001 Stipulation constitutes a reasonable range to be used to determine whether an adjustment to the fuel ratio during the period is necessary. The 63%-77% range reasonably balances the nature of the ratio as a general estimate with the necessity to recognize significant changes in conditions.

The evidence clearly indicates that for the 12 months ending December 31, 2000, the ratio fell outside the 63%-77% deadband. The Public Staff recommended and the Company has agreed that a 60% ratio is reasonable to use in this proceeding. No other party elicited evidence supporting the use of a different ratio. In view of the agreement of the Public Staff and the Company and in the absence of evidence to the contrary, the Commission concludes that it is reasonable for purposes of this proceeding to use the 60% 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.

In its Brief, CUCA takes the position that the Stipulation should not be used to allow Duke to recover the fuel cost associated with one power purchase, in particular. During the test year, Duke purchased 17,985 MWh from TVA. Using the Stipulation, Duke seeks to recover $408,685 of fuel cost associated with this transaction. Under cross-examination by CUCA counsel, Duke witness

Young testified that Duke had requested TVA to provide the actual fuel cost associated with this purchase and TVA had refused, even though Duke believes the contract gave Duke the right to request this information. When asked if Duke had done anything legally to enforce its rights, witness Young testified that Duke had made TVA aware of the issues and had persisted in trying to obtain the fuel cost, but he was not certain of any specific legal actions. CUCA believes that Duke's attempt to apply the Stipulation to this transaction is improper and should be denied because Duke is contractually entitled to receive actual fuel costs from TVA but has not undertaken any action in court to enforce its rights. In the absence of evidence as to actual fuel costs, CUCA recommends that Duke, which bears the burden of proof in this proceeding, should be denied the recovery of any fuel cost associated with the TVA transaction.

The Commission agrees with the general proposition by CUCA that the Stipulation should not be used as a proxy to determine allowable fuel cost from power purchase transactions when actual fuel cost data is available to a utility. Based upon the record in this proceeding, the Commission concludes that Duke took adequate steps to obtain the actual fuel cost for the TVA transaction and that the Stipulation should be applied to determine the fuel cost associated with the TVA power purchase in this case. However, Duke is hereby on notice of TVA's position and that should this issue arise in a future proceeding with a different body of evidence, the same showing may not be sufficient.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

Evidence supporting this finding of fact is contained in the testimony of Company witness Young, CUCA witness O'Donnell, and Public Staff witness Maness.

Title IV of the Clean Air Act Amendments of 1990 (CAAA) requires electric utilities to reduce their aggregate emissions of sulfur dioxide (SO_2). The CAAA adopted a phased-in approach to achieve this goal, establishing national SO_2 limits of 2.4 pounds per million Btu burned for Phase I, 1995 through 1999, and 1.2 pounds per million Btu for Phase II, beginning in 2000. To allow utilities to achieve the required reductions in the most cost-effective manner, the CAAA introduced allowances into the compliance process and assigned each utility an amount to cover a base level of emissions. Each year, the Environmental Protection Agency (EPA) allocates to each utility the number of allowances needed to authorize the utility to emit SO_2 up to its allowed cap under the CAAA. Duke's cap is 185,000 tons per year. To promote the market for allowances, the EPA retains a small portion each year and sells them at auction. The allowances are also tradable between utilities and other parties. The CAAA recognizes that utilities burning high sulfur coal may find it more economical to sell their allowances and install scrubbers, while companies burning lower sulfur coal may find it more economical to purchase allowances to supplement those allocated by the EPA. Duke was in compliance with the Phase I limit. Duke determined that its strategy for Phase II would be to acquire allowances. Duke bought 25,000 in the first EPA auction in 1993 and also made purchases between 1993 and 1999. Duke also earned allowances between 1994 and 1999. At the beginning of the year 2000, Duke had an inventory of roughly 800,000 allowances. Duke used roughly 260,000 of these allowances during the test year.

FERC issued an order in 1993 requiring that the cost of allowances, including zero-cost EPA-allocated allowances, be initially recorded in Account 158.1 - Allowance Inventory, a balance sheet account, by vintage year. As the allowances are used to authorize SO_2 emissions, the weighted average cost available for use in the current year is deducted from inventory and charged to Account 509 - Allowances, a power production expense income statement account. During the test year, Duke charged or expensed $6,108,735 in emission allowances on a total system basis to Account 509. Duke then credited or reduced this amount by $3,453,047 to reflect the cost of emission allowances recovered through off-system sales. Therefore, Duke seeks to include $2,655,688 of emission allowances in its adjusted test period system fuel expense and to recover an allocated amount of $1,763,109 from the North Carolina retail jurisdiction.

Witness Young contended that the Company is entitled to recover the cost of emission allowances as a change in the cost of fuel under G.S. 62-133.2. Witness Young asserted that the cost of emission allowances is inextricably linked with the price of coal. As more coal is burned and more emissions are produced, more allowances are required. He stated that the price of coal typically varies inversely with the sulfur content, and that Duke Power works to balance the relationship between the price of coal and the need for allowances to offset increases in emissions. According to witness Young, both the coal and any required allowances determine the company's total fuel cost; it is impossible to separate them and come to a sound economic decision. Witness Young also analogized emission allowance costs to nuclear fuel disposal costs, which the Commission has determined should be included in fuel cost.

Both witness O'Donnell and witness Maness testified that emission allowance expenses are not fuel costs and therefore are not recoverable under G.S. 62-133.2. Regarding the link between the cost of emission allowances and the price of coal, witness O'Donnell stated that the delivered price of coal to the utility is influenced by a number of factors, including Btu content, ash content, moisture content, grindability, mine location, and the length and volume of the coal contract. Witness O'Donnell pointed to Duke's monthly fuel reports filed with the FERC showing several purchases of lower sulfur coal at lower prices than coal with a higher sulfur content. He also stated that, on a macroeconomic level, coal prices can be influenced by the availability of coal in the market, the demand for coal, and to some extent the cost of other fuels. O'Donnell noted that the linkage between allowances and coal prices can be broken by installing scrubbers or other clean coal technologies.

Witness Maness stated that only the cost of the physical fuel itself (including fabrication costs) and the cost to transport the fuel to the generating facility are appropriately includable in fuel costs for purposes of G.S. 62-133.2. He stated that transportation costs are necessary to bring coal to the point where it can be included in Duke's inventory, whereas an emission allowance is essentially just the cost of a license to operate the units and burn coal. Similarly, nuclear fuel disposal costs are appropriately includable in fuel costs since they are very closely related to the fuel itself because they involve the cost of actually removing and permanently storing the fuel. Witness Maness also stated that it is irrelevant that the most economical substitute for allowances might be additional expenditures to obtain lower sulfur coal. Allowances are part of an overall strategy to limit emissions on a nationwide basis and thus a tool for achieving least cost pollution control. They operate the same way whether the most economical substitute is fuel switching or installing a scrubber.

Witness Maness testified that the correlation between allowance expenses and coal generation is not exact, as the allowances needed for each ton of coal consumed will differ based on the sulfur content of the coal. Maness also noted that Duke Power incurs several types of costs that are considered to be variable with generation but that are not included in the fuel factor. He cited as an example the approximately $177 million in non-fuel power production operation and maintenance (O&M) expenses that are denoted as "energy related" and allocated to jurisdictions and customer classes on the basis of energy consumption in the Company's 1999 cost of service study. Witness Maness agreed that there is a relationship between the cost of allowances and the price differences of coal with different sulfur content, but noted that it may well be the cost of scrubbing that is more closely associated with the cost of allowances in the future if it becomes more competitive with the cost of fuel switching.

Both witness O'Donnell and witness Maness disagreed with the analogy of emission allowance expenses to nuclear fuel disposal costs. Witness O'Donnell stated that the disposal of irradiated nuclear fuel is arguably an integral component of the physical handling, processing, and burning of nuclear fuel. Similarly, witness Maness stated that both nuclear fuel disposal costs and decontamination and decommissioning (D&D) costs are distinguishable from SO_2 allowances because they are very directly connected to the nuclear fuel itself. In addition, Maness stated that the Congress mandated recovery of D&D costs as part of the cost of fuel.

In his rebuttal testimony, witness Young asserted that emission allowance costs are just as much a part of the cost of fuel as are transportation costs. He listed five common characteristics to support this assertion: both costs are directly linked to the coal; both are necessary for the coal to be usable in generation; both vary directly with the amount of fuel used; both are readily identifiable; and both are generally tied to someone other than the supplier of the coal. Young stated that there is no reason why either transportation costs or allowance costs could not be paid to the supplier. He cited as an example one instance where a coal company purchased allowances and in effect attached them to high sulfur coal and sold them as a package. Similarly, one of Duke Power's coal contracts provides for a price adjustment if the sulfur content of the coal exceeds a stated maximum, and the supplier has the option of satisfying the adjustment with allowances rather than cash. On cross-examination, Young agreed that the allowances would go into an allowance cost pool and could be used as needed.

Witness Young disagreed with witness Maness' statement that allowances are fundamentally a tool for achieving least cost pollution control, stating that Maness failed to add that this control is government mandated and affects the cost of coal fired generation. Young asserted that, from the standpoint of the fuel statute, there is very little difference between allowance costs and nuclear fuel disposal costs. Citing the Commission discussion of nuclear fuel disposal costs in Duke Power's 1996 general rate case, he listed four common characteristics to support this assertion: both costs are imposed by the government and relate to the consumption of a specific type of fuel; both are unavoidably linked to the fuel; both vary in proportion to the amount of fuel burned; and both are readily identifiable.

Witness Young also disagreed with Maness' discussion of non-fuel O&M costs that vary with generation and contended that such costs are totally different from allowance costs in that they have nothing to do with fuel. He stated that his testimony was not that allowance costs should be recovered in this case because they are variable production costs but because they are fuel costs; they vary with coal burned and are a necessary ingredient of coal use when they are the least cost choice for environmental compliance.

This is the first proceeding in which the Commission has had to determine whether emission allowance expenses are recoverable in a fuel charge adjustment proceeding pursuant to G.S. 62-133.2. The parties filed post-hearing briefs arguing their positions on this issue, and these briefs may be summarized as follows.

Duke argues that although there were no emission allowances when G.S. 62-133.2 was enacted in 1981, the language of the statute is sufficiently broad to cover future developments. G.S. 62-133.2 does not limit "fuel costs" to the invoice price of the fuel itself, and the Commission considers both transportation costs and nuclear fuel disposal costs as fuel costs in fuel proceedings. Emission allowances are similar to these costs because they are inextricably tied to, and vary in proportion to, the fuel burned; they are necessary for the fuel to be usable in generation; and they are readily identifiable costs. If, instead of using allowances, Duke used lower sulfur coal, the full cost of the more expensive lower sulfur coal could be considered in a fuel proceeding. Using allowances is the least cost way to comply with CAAA and should be encouraged. A general rate case is not well suited to dealing with allowance costs because the volume and cost of allowances will vary considerably from year to year, making it difficult to arrive at a reliable number for rate case purposes. A fuel proceeding, with its annual hearings and its true-up, is a better way to deal with allowance costs.

The Public Staff argues that the issue is simply whether emission allowance costs are "fuel costs" within the meaning of G.S. 62-133.2 and that the Commission has always been reluctant to expand this statutory language. The Commission has used a consistent approach to determine what should be considered as fuel costs for at least the past 25 years, and this approach includes only the cost of the physical fuel itself, costs of transportation to bring the fuel to the plant, and nuclear fuel disposal costs. There are many other costs that the utility must incur to burn its fuel -- such as labor to purchase and handle fuel; fuel analysis: tools, lubricants, and other supplies; coal handling expenses; O&M costs at the facility -- and all of these other costs vary with the amount of coal burned, but none of them are treated as fuel costs. An emission allowance is a license to burn coal that will emit one ton of SO_2; allowance costs are related to a national strategy to reduce emissions, not with the fuel itself. In the absence of a clear expression of intent from the General Assembly, emission allowances should be recovered along with all other non-fuel costs in a general rate case.

The Attorney General argues that disposal of spent nuclear fuel is a necessary cost of burning that fuel; the utility has no choice. Similarly, transportation costs are a necessary cost of burning fuel since the utility has no choice but to transport the fuel to the plant. Purchasing SO_2 emission allowances is not a necessary cost of burning coal since Duke had other choices for meeting the CAAA standards. The decision to use emission allowances is part of a long range strategy to comply with the CAAA. G.S. 62-133.2 provides a streamlined procedure to determine limited issues related to fuel costs and this expedited proceeding is not a proper forum to consider whether Duke's environmental compliance strategy is prudent. Even if it were, Duke did not present enough evidence to carry the burden of proof in this case. Whether emission allowances should be considered in a fuel proceeding is a decision that should be made by the General Assembly, and the General Assembly has not amended the fuel statute to include emission allowances. The South Carolina legislature amended that state's fuel statute to include the cost of SO_2 emission allowances. In Virginia, the statute has not been amended, and the Virginia Commission held that the costs of allowances are not fuel costs under the Virginia statute.

CIGFUR argues that adoption of G.S. 62-133.2 was the culmination of efforts in the 1970s to stabilize electric rates in response to the Arab oil embargo, inefficient fuel procurement practices, and poor nuclear plant performance. Nothing in the history of the statute reflects concern about environmental compliance costs. Recovery of emission allowance costs does not comport with the intent of the fuel statute because emission allowance costs are neither volatile nor unexpected and do not cause great fluctuations in fuel costs. Emission allowance costs are also different from fuel costs because they are incurred as part of a long-range environmental compliance strategy, not as a result of the exigencies of producing power to meet demand. G.S. 62-133.2 is an exception to the rate case statute G.S. 62-133 and should be narrowly construed. If the General Assembly wants to include emission allowances in G.S. 62-133.2, it can amend the statute.

Finally, CUCA disputes Duke's claim that more allowances are required as more coal is burned. CUCA argues that allowances vary not with the volume of coal burned, but rather with the sulfur burned. Further, there are many costs that vary in direct proportion to coal burned yet are excluded from fuel proceedings, such as fuel handling and coal analysis costs. Duke also claims that emission allowances should be considered fuel costs because they are "inextricably linked with the price of coal," but CUCA argues that the price of coal is influenced by a number of factors independent of emission allowances.

The Commission has carefully considered the testimony and briefs on this issue. The Commission concludes that emission allowance expenses should not be considered fuel costs in a fuel proceeding under G.S. 62-133.2 for the following reasons.

G.S. 62-133.2 was enacted in 1982 to establish new procedures for reflecting fuel costs in electric rates. Before this statute, there were other provisions and practices for fuel charge adjustments going back to the mid-1970s. Several parties to this proceeding cite experience and appellate cases under these former fuel charge adjustments to support their interpretation of G.S. 62-133.2. The Commission believes that the most instructive lesson from the history of past fuel charge adjustments can be found in the reasons that prompted fuel charge adjustments in the first place. Fuel charge adjustments were introduced to address the fact that electric utilities' fuel expenses were fluctuating widely, first as a result of the Arab oil embargo and later depending on the availability of nuclear generating plants. These fluctuations made it hard to come up with a representative fuel expense in a general rate case, and abbreviated proceedings to address fuel costs were introduced. Nothing in the legislative history or in the Commission's previous experience with fuel charge adjustments indicates that environmental compliance costs were a driving force behind fuel charge adjustments. Indeed, the CAAA had not even been enacted in 1982, and there were no emission allowances then. The General Assembly could have amended G.S. 62-133.2 to include emission allowance expenses since enactment of the CAAA, but it has not done so.

G.S. 62-133.2 provides an expedited procedure to consider limited issues. The Commission is not convinced that emission allowance expenses present the same kind of issues as fuel costs. Emission allowance expenses are not as likely to be volatile or prone to fluctuations as fuel costs. Indeed, emission allowance expenses reflect a weighted average of emission allowance costs over many years. Further, the decision to use emission allowances is part of a long range strategy and an abbreviated fuel charge proceeding is not an appropriate place to consider the prudence of that strategy. G.S. 62-133.2 is an exception to the general rate case procedures and should not be interpreted expansively. If emission allowances are to be handled through G.S. 62-133.2, the General Assembly should make that decision.

G.S. 62-133.2 allows a rider "for changes in the cost of fuel..." The statute provides that the Commission shall consider evidence of "changes in the price of fuel consumed..." The Commission has followed a consistent practice of interpreting fuel costs under G.S. 62-133.2 as covering the costs of fuel itself, fuel transportation costs and nuclear fuel disposal costs. Expanding this interpretation to cover emission allowance expenses would be a significant departure from this practice, and the Commission is not convinced that there is good reason to do so. As pointed out by the testimony and briefs, there are many costs that the utility must incur in order to burn fuel and produce electricity -- such as the cost of labor involved in supervising the purchase and handling of fuel; routine fuel analysis; material and expense costs such as tools, lubricants, and other supplies; coal handling expenses; and O&M costs at the facility. None of these costs are considered fuel costs for purposes of G.S. 62-133.2, and the Commission is not convinced that emission allowance expenses should be considered fuel costs either. The Commission is not convinced by Duke's argument that emission allowances should be considered fuel costs since they are tied to the price of coal because the Commission finds that many factors influence coal prices.

The Commission recognizes that emission allowance expenses are a new and necessary operating cost to Duke. However, for the foregoing reasons, the Commission concludes that expenses related to emission allowances are not fuel costs. These expenses must be recovered in Duke's base rates along with all other non-fuel costs that the Company has incurred since its last general rate case. There is an implication in Duke's argument that if Duke is not allowed to recover its emission allowance expenses through a fuel charge proceeding, it will lack the incentive to choose the CAAA compliance option that is least cost for its customers. The Commission agrees with the Public Staff that Duke is expected to choose the course of action that produces the lowest possible cost consistent with reliable service regardless of whether emission allowance expenses are fuel or non-fuel.

The Commission notes that witness Young's testimony on cross-examination indicates that Duke may not be recovering the cost of emission allowances under its power sales agreement with Nantahala. Young agreed that it would be appropriate to adjust such transactions to include this cost. While such an adjustment may be appropriate for other purposes, it is not necessary in this proceeding given the Commission's finding that emission allowance expenses are not fuel costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 – 18

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 and the Commission's determination made in Finding of Fact No. 11 regarding the exclusion of the expenses associated with SO_2 emission allowances, the Commission concludes that adjusted test period fuel expenses of $807,624,000 and a base fuel factor of 1.0249¢/kWh ($807,624,000 ÷ 78,797,963 MWH), excluding gross receipts tax, are reasonable and appropriate for use in this proceeding. This approved base fuel factor is .0783¢/kWh lower than the base fuel factor of 1.1032¢/kWh set in the Company's last general rate case, Docket No. E-7, Sub 487.

Witness Shearon testified regarding the results of the Public Staff's investigation of the Experience Modification Factor (EMF). She indicated that her investigation to determine whether the Company properly determined its fuel costs during the test period resulted in no material adjustments. She testified that she incorporated two adjustments recommended by witness Maness. The first adjustment relates to the marketer stipulation and resulted in decreasing Duke Power's North Carolina retail actual test year fuel expense by an amount of $1,617,000. The second adjustment excluded SO_2 emission allowance expenses and reduced the North Carolina retail test period fuel expense by $1,763,000. As discussed previously, the Company accepted the Public Staff's adjustment related to the marketer stipulation and the Commission has determined that the exclusion of the SO_2 emission allowance expenses is reasonable. These two adjustments increased Duke Power's revenue overcollection from $13,228,000 to $16,608,000.

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."

Witness Young testified that the appropriate and reasonable level of adjusted North Carolina retail sales for the test year is 52,575,121 MWH. No party disagreed with this level and the Commission finds it reasonable. The $16,608,000 over-recovered fuel expense can thus be divided by the adjusted North Carolina jurisdictional sales of 52,575,121 MWH to arrive at an EMF decrement of .0316¢/kWh, excluding gross receipts tax, and the associated interest of $2,491,000, calculated using a 10% annual interest rate, can likewise be divided, producing an EMF interest decrement of .0047¢/kWh. The Commission concludes that the EMF decrement of .0316¢/kWh, excluding gross receipts tax, and the EMF interest decrement of .0047¢/kWh are reasonable and appropriate for use in this proceeding.

Accordingly, the overall fuel calculation, incorporating the conclusions reached herein, results in a final net fuel factor of .9886¢/kWh, excluding gross receipts tax.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after July 1, 2001, Duke Power shall adjust the base fuel cost approved in Docket No. E-7, Sub 487, in its North Carolina rates by an amount equal to a .0783¢/kWh decrease (excluding gross receipts tax), and further that Duke Power shall adjust the resultant approved fuel cost by decrements of .0316¢/kWh and .0047¢/kWh (excluding gross receipts tax) for the EMF and EMF interest decrements, respectively. The EMF and EMF interest decrements are to remain in effect for service rendered through June 30, 2002.

2. That Duke Power shall file appropriate rate schedules and riders with the Commission in order to implement these approved fuel charge adjustments no later than 10 days from the date of this Order.

3. That Duke Power shall notify its North Carolina retail customers of these fuel 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 25th of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

je060701.01

APPENDIX A

DOCKET NO. E-7, SUB 685

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
Application of Duke Energy Corporation	)	NOTICE TO CUSTOMERS
Pursuant to G. S. 62-133.2 and NCUC	)	OF CHANGE IN RATES
Rule R8-55 Relating to Fuel Charge	)	
Adjustments for Electric Utilities	)	

NOTICE IS GIVEN that the North Carolina Utilities Commission entered an Order on June 25, 2001, after public hearing, approving a fuel charge net rate increase of approximately $25,867,000 on an annual basis in the rates and charges paid by the retail customers of Duke Power in North Carolina. It is intended that the net rate increase will be in effect for service rendered for the period of July 1, 2001 through June 30, 2002. The rate increase was ordered by the Commission after review of Duke Power's fuel expense during the 12-month period ended December 31, 2000, 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.

The change in the approved fuel charge will result in a monthly net rate increase of approximately 49¢ for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th of June 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-22, SUB 394

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 North Carolina General Statute 62-133.2 and North Carolina Utilities Commission Rule R8-55	))))	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, November 20, 2001, at 10:00 a.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 Lorinzo L. Joyner and James Y. Kerr II

APPEARANCES:

For Dominion North Carolina Power:

Robert W. Kaylor, 225 Hillsborough Place, Suite 480, Raleigh, North Carolina 27603

For Carolina Industrial Group for Fair Utility Rates:

Ralph McDonald, Bailey and Dixon, L.L.P., Attorneys at Law, P. O. Box 1351, Raleigh, North Carolina 27602-1351

For the Using and Consuming Public:

Vickie L. Moir, 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, P.O. 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 within 12 months after the last general rate case order for each utility 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 last general rate case. In addition to the increment or decrement to reflect changes in the cost of fuel and the fuel component of purchased power, the Commission is required to incorporate in its fuel cost determination the experienced over-recovery or underrecovery of reasonable fuel expenses prudently incurred during the test year. The last general rate case order for Dominion North Carolina Power (Dominion NC Power or the Company) was issued by the

Commission on February 26, 1993, in Docket No. E-22, Sub 333. The last order approving a fuel charge adjustment for the Company was issued on December 13, 2000 in Docket No. E-22, Sub 388.

On September 17, 2001, Dominion North Carolina Power filed its fuel charge adjustment application and supporting testimony and exhibits pursuant to G.S. 62-133.2 and Commission Rule R8-55 relating to fuel charge adjustments for electric utilities. Dominion North Carolina Power filed testimony and exhibits of the following witnesses: A. Brian Cassada, Charles Stadelmeier and Glenn A. Pierce. The Company filed certain Revised Schedules on September 20, 2001. The Company filed revised testimony and schedules of Messrs. Cassada and Pierce on November 2, 2001. The Company also filed information and workpapers required by North Carolina Utilities Commission Rule R8-55(d).

On September 27, 2001, the Commission issued an Order Scheduling Hearing and Requiring Public Notice.

The Carolina Group for Fair Utility Rates (CIGFUR I) filed a Petition to Intervene on October 1, 2001, which was allowed by Commission Order issued October 3, 2001.

By Order issued on October 8, 2001, the Commission rescheduled the hearing from November 13, 2001 to November 20, 2001 and required public notice be changed accordingly.

On October 12, 2001, the Public Staff filed a motion to extend the time for it and other intervenors to file testimony. This motion was allowed by Order issued on October 15, 2001.

The Attorney General filed Notice of Intervention on October 24, 2001.

On November 5, 2001, the Public Staff filed the affidavits of James S. McLawhorn, Electric Engineer, and Darlene P. Peedin, Staff Accountant. On November 9, 2001, the Public Staff filed the revised affidavits of Mr. McLawhorn and Ms. Peedin. The Public Staff also filed Notice that the affidavits would be used in evidence in lieu of the oral testimony in the absence of a request to cross examine the affiants. No party requested the right to cross examine the Public Staff.

On November 9, 2001, Dominion North Carolina Power filed a Notice of Affidavits, which indicated that the Company would enter its direct testimony into the record by affidavit at the hearing in the absence of an objection from any party. No such objection was raised by any party.

On November 19, 2001, the Company filed its Affidavit of Publication of this proceeding.

The evidentiary hearing was held on November 20, 2001, at the time and place shown above. The prefiled direct testimony of the Company's witnesses was admitted into evidence by affidavit. The Revised Affidavits of Public Staff witnesses McLawhorn and Peedin and the exhibits of all the witnesses were also admitted into evidence. No public witnesses appeared at the hearing.

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 North Carolina 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 North Carolina 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, 2001.

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

4. The fuel proceeding test period per book system sales are 72,608,810 MWh.

5. The fuel proceeding test period per book system generation is 76,896,777 MWh, which includes various generation as follows:

Generation Type	MWh
Coal	36,819,740
Combustion Turbine	1,392,272
Heavy Oil	3,478,779
Natural Gas	0
Nuclear	28,631,497
Hydro	3,044,162
Pumped Storage (Pumping)	(3,277,135)
Power Transactions	
NUG	3,411,916
Other	6,912,291
Sales for Resale	(3,516,745)

6. The nuclear capacity factor which is appropriate for use in this proceeding is 91.02%, which is the estimated nuclear capacity factor for the rate year ending December 31, 2002.

7. The adjusted test period system sales for use in this proceeding are 73,066,530 MWh.

8. The adjusted test period system generation for use in this proceeding is 77,401,047 MWh, and is categorized as follows:

Generation Type	MWh
Coal	38,081,749
Combustion Turbine	1,441,104
Heavy Oil	3,601,183
Natural Gas	0
Nuclear	27,342,109
Hydro	3,044,162
Pumped Storage (Pumping)	(3,277,135)
Power Transactions	
NUG	3,537,002
Other	7,147,618
Sales for Resale	(3,516,745)

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

A. The coal fuel price is $15.55/ MWh.
B. The nuclear fuel price is $3.84/ MWh.
C. The heavy oil fuel price is $37.92/MWh.
D. The natural gas fuel price is $0/MWh.
E. The internal combustion turbine fuel price is $52.50/MWh.
F. The fuel price of other power transactions is $9.19/MWh.
G. Hydro and pumped storage have a zero fuel price.

10. The adjusted test period system fuel expense for use in this proceeding is $870,149,750.

11. The proper fuel factor for this proceeding is 1.191¢/kWh, excluding gross receipts tax, or 1.230¢/kWh, including gross receipts tax.

12. Setting fuel costs associated with purchases from power marketers and certain other sellers at a level equal to 60% of the energy portion of the purchase price is reasonable for use in this proceeding.

13. The appropriate North Carolina test period jurisdictional fuel expense undercollection is $1,701,046. The adjusted North Carolina jurisdictional test year sales are 3,191,260 MWh.

14. The appropriate Experience Modification Factor (EMF) for this proceeding is an increment of .053¢/kWh, excluding gross receipts tax, or .055¢/kWh, including gross receipts tax.

15. The final fuel factor is 1.244¢/kWh, excluding gross receipts tax, or 1.285¢/kWh, including gross receipts tax.

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. In North Carolina Utilities Commission Rule R8-55(b), the Commission has prescribed the 12 months ending June 30th as the test period for Dominion North Carolina Power. The Company's filing was based on the 12 months ended June 30, 2001.

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 fuel procurement practices were filed with the Commission in Docket No. E-22, Sub 335, on April 2, 1993, and were in effect throughout the twelve months ended June 30, 2001. In addition, the Company files monthly reports of its fuel costs pursuant to Rule R8-52(a).

No party offered testimony contesting 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 Pierce and Stadelmeier and the affidavit of Public Staff witness McLawhorn.

Witness Pierce testified that the test period per book system sales were 72,608,810 MWH and test period per book system generation was 76,896,777 MWH. The test period per book system generation is categorized as follows:

Generation Type	MWH
Coal	36,819,740
Combustion Turbine	1,392,272
Heavy Oil	3,478,779
Natural Gas	0
Nuclear	28,631,497
Hydro	3,044,162
Pumped Storage (Pumping)	(3,277,135)
Power Transactions	
NUG	3,411,916
Other	6,912,291
Sales for Resale	(3,516,745)

The 36,819,740 MWh of per book system coal generation includes 3,378,594 of ODEC generation. The 28,631,497 MWh of per book system nuclear generation includes 1,771,271 MWh of ODEC generation.

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 facilities and any unusual events.

Company witness Stadelmeier testified that the Company achieved a system nuclear capacity factor of 95.3% for the July 1, 2000, to June 30, 2001, test period. Public Staff witness McLawhorn stated that the most recent (1995-1999) NERC five-year average nuclear capacity factor for pressurized water reactor units is 80.61%. Witness Stadelmeier normalized the system nuclear capacity factor to a level of 91.02%, which is the estimated nuclear capacity factor for the twelve months ending December 2002. Witness McLawhorn agreed that the nuclear capacity factor of 95.3% as achieved by the Company should be normalized to the proposed 91.02% factor. No other party offered or elicited testimony on the normalized nuclear capacity factor. In the absence of evidence to the contrary, the Commission concludes that the July 1, 2000, to June 30, 2001 test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 91.02% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

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

Witness Pierce indicated that the Company's system sales data for the twelve months ended June 30, 2001, was adjusted for weather normalization, customer growth and increased usage in accordance with Commission Rule R8-55(d)(2). Witness Pierce adjusted total Company sales by 457,720 MWh. This adjustment is the sum of adjustments for increased usage, weather normalization and customer growth of (267,751) MWh, 486,907 MWh and 257,415 MWh, respectively, and an adjustment of (18,851) 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 the adjustments due to increased usage, weather normalization, and customer growth of (267,751) MWh, 486,907 MWh, and 257,415 MWh, respectively, and an adjustment of (18,851) MWh from restatement of non-jurisdictional ODEC sales from production level to sales level are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Company witness Pierce presented an adjustment to per book MWh generation for the 12-month period ended June 30, 2001, due to weather normalization, customer growth, and increased usage of 504,270 MWh, to arrive at witness Stadelmeier's adjusted generation level of 77,401,047 MWh. Witness McLawhorn reviewed and accepted witness Pierce's adjustment to per book MWh generation for the 12-month period ended June 30, 2001, due to weather normalization, customer growth and increased usage. Witness McLawhorn also accepted witness Stadelmeier's adjusted generation level of 77,401,047 MWh which includes various generation as follows:

Generation Type	MWh
Coal	38,081,749
Combustion Turbine	1,441,104
Heavy Oil	3,601,183
Natural Gas	0
Nuclear	27,342,109
Hydro	3,044,162
Pumped Storage (Pumping)	(3,277,135)
Power Transactions	
NUG	3,537,002
Other	7,147,618
Sales for Resale	(3,516,745)

The 38,081,749 MWh of adjusted test period coal generation includes 3,479,952 of ODEC generation. The 27,342,109 MWh of adjusted test period nuclear generation includes 1,679,435 MWh of ODEC generation.

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

The evidence for these findings of fact is contained in the testimony of Company witnesses Stadelmeier and Pierce and the affidavit of Public Staff witness McLawhorn.

Witness Stadelmeier testified that the Company's proposed fuel factor is based on June 2001 fuel prices as follows: 1) coal price of $15.55/MWh; 2) nuclear fuel price of $3.84/MWh; 3) heavy oil price of $37.92/MWh; 4) natural gas price of $0/MWh; 5) internal combustion turbine price of $52.50/MWh; 6) other power transactions price of $9.19/ MWh; and 7) hydro and pumped storage at a zero price. Witness McLawhorn accepted witness Stadelemeier's fuel prices.

In the absence of any evidence to the contrary, the Commission concludes that the fuel prices recommended by Company witness Stadelmeier and accepted by Public Staff witness McLawhorn are reasonable and appropriate for use in this proceeding.

Company witness Stadelmeier testified that he calculated the level of normalized fuel expenses by multiplying the normalized generation amounts for the Company's generating units by actual June 2001 fuel prices. The level of test year normalized fuel expense resulting from this calculation is $870,149,750. The Public Staff accepted this level of test year normalized fuel expense.

Public Staff witness McLawhorn calculated a proposed fuel factor for the twelve months ended December 31, 2002 by dividing the normalized fuel expense of $870,149,750 by the adjusted level of test year system MWh sales of 73,066,530 MWh. This calculation results in a proposed fuel factor of 1.191¢/ kWh (excluding gross receipts tax), as set forth on McLawhorn Exhibit I. The Company accepted witness McLawhorn's calculation. When this fuel factor is reduced by the base fuel component approved in the Company's most recent general rate case (1.091¢/kWh), the procedure demonstrated on Exhibit No. GAP-1, Schedule 3, the resulting fuel cost (Rider A) is .100¢/kWh (excluding gross receipts tax) and .103¢/kWh (including gross receipts tax).

The Commission concludes that adjusted fuel test period expenses of $870,149,750 and the fuel cost rider (Rider A) increment of .100¢/kWh, excluding gross receipts tax, or a .103¢/kWh increment, including gross receipts tax, are reasonable and appropriate for use in this proceeding. No party opposed this calculation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is contained in the testimony of Public Staff witness Peedin. Ms. Peedin testified that during the test year Dominion NC Power purchased power from a large number of power marketers and other suppliers that did not provide it with the actual fuel costs associated with those purchases. To address this situation, Ms. Peedin recommended that the Commission adopt the Stipulation reached by the Public Staff, the Attorney General, Duke Power, CP&L, and Dominion NC Power regarding the proper methodology for determining the fuel costs associated with purchases from power marketers and other suppliers for purposes of this proceeding. CP&L filed the Stipulation with the Commission on June 4, 1999, in Docket No E-2, Sub 748. The Stipulation, which was filed as Peedin Exhibit I in this proceeding, is intended by the parties to be applicable to the 1999, 2000, and 2001 fuel cost proceedings. The Stipulation generally provides that for purchases from power marketers, the utility shall assume that the fuel cost component of the purchase equals 70% of the energy portion of the purchase price. For purchases from other sellers that do not provide actual costs, the fuel cost component shall be determined using an appropriate ratio.

Ms. Peedin testified that 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." As a result of this Order, the Public Staff, Duke, CP&L, Dominion NC Power, and the Attorney General entered into a stipulation in 1997 regarding the proper methodology for determining the fuel cost associated with power purchased from power marketers and other suppliers. The methodology adopted by the parties used the three utilities' own off-system sales as the basis for determining a proxy for the fuel costs associated with applicable purchases. This methodology was accepted as reasonable by the Commission in each of the utilities' fuel proceedings in 1997 and 1998.

Ms. Peedin testified that upon the expiration of the 1997 stipulation, the Public Staff analyzed the fuel component of the utilities' off-system sales set forth in the Monthly Fuel Reports for the twelve months ended October 31, 1998. This analysis, which was similar to that performed by the Public Staff in connection with the earlier stipulation, became the basis for the 70% ratio used in the 1999-2001 Stipulation. The methodology used for the 1999-2001 Stipulation has already been accepted by the Commission as reasonable in the 1999 CP&L and Dominion NC Power fuel proceedings, in the 2000 Duke, CP&L, and Dominion NC Power fuel proceedings, and in the 2001 Duke and CP&L fuel proceedings. Additionally, although the 1999-2001 Stipulation had not yet been finalized at the time of Duke's 1999 fuel proceeding, the underlying analysis was the basis for the Public Staff's recommendation, which was accepted by the Commission, that a 70% ratio be applied to the appropriate purchases in that case. Thus, in each fuel case since the beginning of 1997, the

Commission has accepted as reasonable, under the criteria set forth in the 1996 Duke case, the use of the utilities' off-system sales to determine a fuel cost proxy for applicable purchases.

Ms. Peedin stated that the Public Staff continues to consider it reasonable to use the utilities' off-system sales as a basis for the proxy fuel cost 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. Additionally, the information used by the Public Staff to determine the off-system sales fuel ratio was derived from the Monthly Fuel Reports filed with the Commission and in the opinion of the Public Staff is reasonably reliable. Ms. Peedin also stated that 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 recommended that the Commission adopt the 1999-2001 Stipulation for purposes of this proceeding.

Ms. Peedin testified that included in the Stipulation is a provision which contemplates the possibility of an update to the 70% ratio during the effective period. The Stipulation states that "[t]he 70% ratio may be adjusted if a review of power sales reported to the Commission by the utilities during the most recent 12 months indicates that the total fuel cost to total energy cost ratio for such sales falls outside the range of 63% to 77%. If such ratio falls outside the range, the parties agree they will meet and negotiate the appropriate ratio."

Ms. Peedin testified that in order to determine if an update should be pursued, the Public Staff performed a review of the utilities' off-system sales set forth in the Monthly Fuel Reports, for the twelve months ended December 31, 2000. She stated that the Public Staff's analyses resulted in fuel percentages ranging from 57.36% to 60.88%, as set forth on Peedin Exhibit II. Ms. Peedin stated that after reviewing all the data and calculations, the Public Staff concluded that they supported a finding that the off-system sales ratio has fallen below the lower end of the 63%-77% range and, therefore, that the ratio should be reduced for purposes of determining the Experience Modification Factor (EMF) in this proceeding to a level more consistent with the fuel percentage experienced with regard to off-system sales during 2000. Ms. Peedin recommended the use of a 60% ratio in this proceeding to determine the fuel costs of power purchases subject to the application of the off-system sales fuel percentage. She indicated that the use of this ratio results in reducing North Carolina Power's fuel costs for the purposes of calculating the EMF by $383,019, on a North Carolina retail basis in this proceeding. The Company did not contest the Public Staff's recommendation to adjust Dominion NC Power's filing to reflect the 60% of energy charges associated with certain purchases as fuel expense. Ms. Peedin stated that she understood that the Company agreed with the adjustment.

The Commission concludes, as it has in past cases, that the methodology underlying the Stipulation, 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 can be accepted under G.S. 62-133.2. As the Public Staff has testified, 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, as it has since 1997, that the fuel-to-energy cost ratio exhibited by the utilities' sales is similar to the ratio 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 Public Staff's testimony, 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 are subject to Commission review. Third, the methodology is supported by both the Public Staff and the Attorney General, on the one hand, and by the three utilities subject to the fuel clause statute, on the other, parties who represent different and sometimes adversarial interests. Finally, no party to this proceeding elicited evidence of any alternative information available concerning the fuel cost component of purchases made from power marketers or other relevant sellers of power to Dominion NC Power. Therefore, the Commission concludes that the methodology underlying the 1999-2001 Stipulation meets the criteria set forth in the 1996 Duke fuel case Order, and is reasonable for purposes of this proceeding as the method of determining the proxy fuel cost.

In reaching this conclusion, the Commission recognizes that the Stipulation was not signed by all parties to this proceeding. The Commission recognizes that such partial settlements of a case are not binding on the Commission and will be received into evidence and weighed along with the entire record. Moreover, non-signing parties may contest the terms of the Stipulation in each proceeding in which it is presented. However, the Commission notes that in this proceeding no party elicited evidence supporting any alternative methodology to the one that the Commission has accepted for several years. The Commission can find no good reason to depart from its long-standing approach to this issue. In addition, as recognized by the Commission in the past, use of the Stipulation resolves uncertainty Dominion NC Power and other electric utilities would face regarding the future recovery of fuel costs associated with otherwise economical purchases from power marketers that lower overall costs.

Given the fact that the Commission has concluded that the methodology underlying the 1999-2001 Stipulation is reasonable for purposes of this proceeding, the question remains as to the appropriate fuel ratio to be used in this instance. The Stipulation states that, "[t]he 70% ratio may be adjusted if a review of power sales reported to the Commission by the utilities during the most recent 12 months indicates that the total fuel cost to total energy cost ratio for such sales falls outside the range of 63% to 77%. If such ratio falls outside this range, the parties agree they will meet and negotiate the appropriate ratio."

In making its determination on this matter, the Commission first notes that it believes that the general approach taken in the Stipulation of identifying a specific ratio to be used for a specific period of time, and then identifying a deadband around that ratio to control whether the ratio might be changed during that period, is reasonable. The Commission reaches this conclusion for two primary reasons. First, the fuel ratio is by nature a general estimate to be used to determine a proxy fuel cost; it is not a precise calculation of actual fuel costs. Second, under the terms of the Stipulation, the agreed-upon fuel ratio is only in effect for a limited period of time (three years). Given these facts, the Commission does not consider it necessary to change the fuel ratio each year during the three-year period for relatively minor changes. The Commission is of the opinion that the 63%-77% deadband set forth in the 1999-2001 Stipulation constitutes a reasonable range to be used to determine whether an adjustment to the fuel ratio during the period is necessary. The 63%-77% range reasonably balances the nature of the ratio as a general estimate with the necessity to recognize significant changes in conditions.

The evidence clearly indicates that for the 12 months ending December 31, 2000, the ratio fell outside the 63%-77% deadband. The Public Staff recommended and the Company has not contested the use of a 60% ratio in this proceeding. No other party elicited evidence advocating the use of a different ratio. In view of the apparent agreement of the Public Staff and the Company and in the absence of evidence to the contrary, the Commission concludes that it is reasonable for purposes of this proceeding to use the 60% 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. 13 & 14

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Cassada and Pierce and the affidavits of Public Staff witnesses Peedin and McLawhorn.

Company witness Cassada testified that the Company under-collected its fuel expenses by $1,782,934 during the test year ending June 30, 2001. Company witness Pierce testified that the adjusted North Carolina jurisdictional fuel clause test year sales are 3,191,260 MWh.

Public Staff witness Peedin testified regarding the results of the Public Staff's investigation of the Experience Modification Factor (EMF). She indicated that her investigation to determine whether the Company properly determined its fuel costs during the test period resulted in three adjustments. The first adjustment relates to the marketer stipulation and resulted in decreasing Dominion North Carolina Power's N.C. retail fuel expense by an amount of $383,019 discussed above in the Evidence and Conclusions for Finding of Fact No. 12. The second adjustment relates to an error that the Company discovered in one of the monthly allocation factors used to calculate the N.C. retail portion of test year fuel costs. Correction of this factor resulted in a reduction of $85,119. Witness Peedin also adjusted test year fuel costs to include the annual billing for Decontamination and Decommissioning cost, which resulted in increasing N.C. retail test year fuel costs by $386,250. The Company did not contest any of Ms. Peedin's three adjustments. The combination of the three adjustments reduced the total test year fuel underrecovery from $1,782,934 to $1,701,046.

N.C.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.

Company witness Pierce indicated that the appropriate and reasonable level of adjusted N.C. retail sales for the test year is 3,191,260 MWh. No party disagreed with this level and the Commission finds it reasonable. The $1,701,046 under-recovered fuel expense can thus be divided by the adjusted North Carolina jurisdictional sales of 3,191,260 MWh to arrive at an EMF increment of .053¢/kWh, excluding gross receipts tax. The Commission concludes that the EMF increment of .053¢/kWh, excluding gross receipts tax, or .055¢/kWh, including gross receipts tax, is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is cumulative and is contained in the testimony and exhibits of Company witnesses Cassada and Pierce and the affidavits of Public Staff witnesses Peedin and McLawhorn.

Based upon our prior findings in this proceeding, the Commission finds that the final net fuel factor, including gross receipts tax, approved for usage in this case is 1.285¢/kWh.

The fuel factor is determined as follows:

Normalized System Fuel Expense	$870,149,750
System kWh Sales at Sales Level	73,066,529,939
Test Year North Carolina Retail Fuel Underrecovery	$1,701,046
North Carolina Retail kWh Sales At Sales Level	3,191,260,216
Base Fuel Component Approved in Docket No. E-22, Sub 333 (cents per kWh)	1.091
Gross Receipts Tax Factor	1.03327

Fuel Cost Rider A (excluding gross receipts tax) =
[($870,149,750 X 100)/73,066,529,939]-1.091 = .100¢/kWh

Fuel Cost Rider A (including gross receipts tax) =
.100¢/kWh x 1.03327 = .103¢/kWh

Fuel Cost Rider B (excluding gross receipts tax) =
[($1,701,046 X 100)/3,191,260,216] = .053¢/kWh

Fuel Cost Rider B (including gross receipts tax) =
.053¢/kWh x 1.03327 = .055¢/kWh

Effective 1/1/2002
(Including Gross Receipts Tax)

Base Fuel Factor	1.127
EMF/Rider B	.055
Fuel Cost Rider A	.103
FINAL FUEL FACTOR	1.285

IT IS, THEREFORE, ORDERED as follows:

1. That effective beginning with usage on and after January 1, 2002, Dominion North Carolina Power shall adjust the base fuel component in its North Carolina retail rates approved in Docket No. E-22, Subs 333 and 335, by an increment Rider A of .100¢/kWh, excluding gross receipts tax, or .103¢/kWh, including gross receipts tax;

2. That an EMF Rider increment (Rider B) of .053¢/kWh, excluding gross receipts tax, or .055¢/kWh, including gross receipts tax, shall be instituted and remain in effect for usage from January 1, 2002 until December 31, 2002;

3. That Dominion North Carolina 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; and,

4. That Dominion North Carolina 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.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

je120601.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO E-22, SUB 394

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	)	NOTICE TO CUSTOMERS
North Carolina General Statute 62-133.2 and North	)	OF RATE INCREASE
Carolina Utilities Commission Rule R8-55	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 19, 2001, after public hearing, approving a $2,489,183 increase in the annual rates and charges paid by the retail customers of Dominion North Carolina Power in North Carolina. The rate increase will be effective for usage on and after January 1, 2002. The rate increase was approved by the Commission after a review of Dominion North Carolina Power's fuel expenses during the 12-months test period ended June 30, 2001, and represents changes experienced by the Company 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 rate increase of approximately 78¢ for each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION
This the 19th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-2, SUB 778
DOCKET NO. EMP-5, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Petition of Carolina Power & Light	)	
Company to Transfer Certificates of	)	
Public Convenience and Necessity	)	ORDER APPROVING
Granted in Docket Nos. E-2, Sub 733	)	PETITION IN PART
and E-2, Sub 763 to Subsidiaries	)	
of Progress Energy Ventures, Inc.	)	

HEARD: Wednesday, June 27, 2001, at 10:00 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Jo Anne Sanford, presiding, and Commissioners Judy Hunt, J. Richard Conder, Robert V. Owens, Jr., Sam J. Ervin, IV, and Lorinzo L. Joyner

APPEARANCES:

For Carolina Power & Light Company:

Len S. Anthony, Manager – Regulatory Affairs, Post Office Box 1551 Raleigh, North Carolina 27602-1551

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, P.C., Suite 1735, Two Hannover Square, 434 Fayetteville Street Mal, Raleigh, North Carolina 27601

For Carolina Industrial Group for Fair Utility Rates:

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

For the North Carolina Attorney General:

Leonard G. Green, N.C. Department of Justice, Post Office Box 629, Råleigh, North Carolina 27602

For the Public Staff:

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

BY THE COMMISSION: On March 7, 2001, Carolina Power & Light Company (CP&L) filed a petition seeking authority to transfer certificates of public convenience and necessity which were granted to CP&L in Docket Nos. E-2, Sub 733 and E-2, Sub 763.[1] The certificates authorize construction of 1280 MW of electric generating capacity in Richmond County and 480 MW of electric generating capacity in Rowan County. CP&L proposes to transfer the certificates to new subsidiaries of Progress Energy Ventures, Inc. (Energy Ventures). The new subsidiaries were identified as Richmond County Power Company, LLC and Rowan County Power Company, LLC. Energy Ventures is a subsidiary of Progress Energy, Inc., that was created to engage in the wholesale energy market.

On March 14, 2001, the Commission issued an order requiring the prefiling of testimony and scheduling a hearing. The order also required CP&L to provide public notice of the proceeding, and CP&L subsequently filed affidavits of publication showing that public notice had been given as required.

On March 27, 2001, Carolina Industrial Group for Fair Utility Rates (CIGFUR II) filed a petition to intervene, which was granted by order dated March 29, 2001. On March 28, 2001, the North Carolina Attorney General filed a notice of intervention pursuant to G.S. 62-20. On April 12, 2001, Rowan Generating Company, LLC filed a petition to intervene, which was granted on April 19, 2001. On April 30, 2001, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted on May 2, 2001.

On April 11, 2001, CP&L filed the direct testimony and exhibits of its two witnesses, Verne Ingersoll and Larry Smith.

The Public Staff moved for extensions of time for the filing of intervenor testimony, which were granted. On June 22, 2001, the Public Staff filed the joint direct testimony of Dennis J. Nightingale, Elise Cox and Thomas W. Farmer, Jr., and CUCA filed the direct testimony of Kevin W. O'Donnell. No other party filed testimony in this case.

Also on June 22, 2001, CP&L filed an additional exhibit of Verne Ingersoll, a draft purchase power agreement with Richmond County Power Company, LLC. On June 25, 2001, CP&L filed the rebuttal testimony and exhibits of Verne Ingersoll.

The hearing was held as scheduled on June 27, 2001. At the beginning of the hearing, CUCA moved to strike the rebuttal testimony and exhibits of CP&L witness Verne Ingersoll. The Commission partially granted CUCA's motion and struck portions of Ingersoll's rebuttal testimony and exhibits relating to the market value of the facilities. At the hearing, CP&L presented the testimony and exhibits of Verne Ingersoll and Larry Smith; CUCA presented the testimony of Kevin W. O'Donnell; and the Public Staff presented the joint testimony and exhibits of Dennis J. Nightingale, Elise Cox and Thomas W. Farmer, Jr.

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[1] To the extent the facilities authorized by the certificates have already been constructed, the petition is interpreted as seeking authority to transfer the facilities themselves. It is also implicit that CP&L proposes to transfer the sites, which have room for additional generation.

Based on the testimony and exhibits presented at the hearing and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. CP&L is duly organized as a public utility under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. CP&L is engaged in the business of generating, transmitting, distributing and selling electricity in its assigned territory in North and South Carolina.

2. CP&L has obligations to provide electricity to both retail and wholesale customers. CP&L's obligation to serve retail customers is established by North Carolina law. CP&L's obligation to serve wholesale customers is based upon contracts voluntarily entered into by CP&L with the wholesale customers. These wholesale contracts fall into three categories: unit sales contracts, on-system native load priority contracts, and off-system native load priority contracts.

3. Approximately 30 percent of CP&L's load is associated with its wholesale obligations. CP&L's total system load in 2004 is projected to be approximately 13,000 MW. Of this amount, approximately 4000 MW is projected to be associated with CP&L's wholesale contractual obligations, both unit sales and native load priority contracts. CP&L's wholesale contracts are of varying lengths. By June 2004, several of CP&L's wholesale contracts, representing over 2300 MW of wholesale load, will expire.

4. By the Order Granting Certificates dated November 2, 1999, in Docket No. E-2, Sub 733 and the Order Approving Application dated August 17, 2000, in Docket No. E-2, Sub 763, the Commission granted certificates of public convenience and necessity to CP&L authorizing construction of 1280 MW of generating capacity in Richmond County and 480 MW of generating capacity in Rowan County. The Commission granted CP&L the certificates to construct these generating facilities in Richmond and Rowan Counties on the basis of evidence that they were needed in order for CP&L to provide reliable electric service to both its retail and wholesale customers.

5. In the Sub 733 proceeding, CP&L specifically committed that it "will not allow its retail electric customers to be disadvantaged in any manner, either from a quality of service or rate perspective, as a result of its participation in the wholesale power market." The Commission incorporated CP&L's commitment into Ordering Paragraph No. 4 of the Order Granting Certificates in Sub 733. Both the Order Granting Certificates in Sub 733 and the Order Approving Application in Sub 763 specifically reserved the ratemaking treatment of the new facilities for future proceedings.

6. There are concerns that CP&L's participation in the wholesale market potentially exposes CP&L's retail customers to either insufficient reserves, as more native load priority contracts are signed, or excessive reserves, if wholesale contracts expire and are not renewed and wholesale load is lost. In order to address the potential problems associated with CP&L's participation in the wholesale market, It is reasonable for CP&L to begin separating its retail and wholesale businesses.

To do so, it is also reasonable for CP&L to begin to transfer its wholesale obligations and a portion of its generating system resources to an affiliate that will participate in the wholesale market, so long as the transfer of generating facilities is accompanied by a related transfer of wholesale obligations or retail ratepayers are protected and made whole for the loss of access to the generating facilities transferred.

7. CP&L has unit sales contracts associated with the new Rowan generating facilities. These contracts have assignability provisions, and they can be transferred along with the Rowan generating facilities. The transfer of the Rowan generating facilities to an affiliate will not impair CP&L's ability to provide reliable, cost effective electric service to its retail customers.

8. CP&L's native load priority wholesale contracts are backed by the full system resources of CP&L, and these contracts cannot be transferred away from CP&L at this time.

9. The Rowan and Richmond facilities are located at desirable sites that were acquired by CP&L and have transmission access, natural gas supply, water, transportation, and environmental approvals.

10. It is reasonable and in the public interest for CP&L to transfer at this time the certificate and the 480 MW of generating facilities at the Rowan County site approved by the Commission in Docket Nos. E-2, Sub 733, and E-2, Sub 763, together with the transfer of the unit sales contracts associated with these facilities.

11. The transfer of the Rowan generating facilities will initially be recorded at net book cost, but this is subject to adjustment in the event the Commission determines that the market value of the facilities at transfer exceeded net book cost.

12. The appropriate terms and rates to be included in the service agreement to be entered into by CP&L pursuant to which CP&L will provide services to the Rowan generating facilities will be addressed in a subsequent proceeding under G.S. 62-153.

13. Based on the evidence presented herein, it is not in the public interest for CP&L to transfer the Richmond generating facilities at this time. This decision is without prejudice to CP&L's ability to renew the request to transfer the Richmond facilities in light of changed circumstances.

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDING OF FACT NO. 1

This finding is essentially jurisdictional in nature and is not in controversy.

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDING OF FACT NO. 2

This finding of fact is supported by the testimony of CP&L witness Ingersoll, the testimony of the Public Staff witnesses, and the laws of North Carolina as set forth in Chapter 62 of the North Carolina General Statutes.

Witness Ingersoll testified that CP&L provides service to its wholesale customers under contracts with differing terms and conditions. He explained that these contracts can be grouped into three categories: (1) unit sales, (2) on-system native load priority, and (3) off-system native load priority.

A "unit sales" contract is one by which CP&L agrees to provide electric power from a particular generating unit to a particular wholesale customer. This power is firm power available to this customer provided the generating unit in question is operational. If the generating unit is not in operation, CP&L has no obligation to provide power to the customer at all. CP&L expects approximately 459 MW of unit sales contracts, all associated with the new Rowan generating facilities discussed below.

A "native load priority" contract is one by which CP&L is obligated to provide electric power to wholesale customers with reliability equal to that which CP&L provides to its retail customers. Witness Ingersoll testified that, historically, such wholesale customers have included the City of Fayetteville, the Eastern Municipal Power Agency, the North Carolina Electric Membership Corporation (NCEMC), French Broad Electric Membership Corporation, the Town of Waynesville, and the City of Camden in South Carolina. All of these customers are located within CP&L's traditional service territory, or "on-system." Native load priority contracts with on-system customers total approximately 3250 MW. CP&L has also signed native load priority contracts with two wholesale customers located outside its service territory, and these are called "off-system" native load priority contracts. One of these contracts is with the South Carolina Public Service Authority, often called Santee Cooper, and the other is with NCEMC to serve certain of its load obligations in Duke Power Company's control area. These two contracts involve approximately 650 MW of load.

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDING OF FACT NO. 3

The evidence supporting this finding of fact is contained in the testimony and exhibits of CP&L witness Ingersoll and the joint testimony of the Public Staff witnesses.

CP&L witness Ingersoll and the Public Staff witnesses indicated that CP&L's percentage of wholesale load varies from year to year, but that approximately 30 percent of CP&L's load is wholesale. CP&L witness Ingersoll's exhibits demonstrate that CP&L's total system load in the year 2004 is projected to be approximately 13,000 MW. Of this amount, Ingersoll testified that approximately 4000 MW is wholesale load. He further testified that the wholesale contracts are of varying lengths and that by June 2004, current wholesale contracts involving over 2300 MW will expire.

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDINGS OF FACT NOS. 4 - 5

These findings are supported by the testimony of CP&L witness Ingersoll, the testimony of the Public Staff witnesses, and the records of the Commission in Docket Nos. E-2, Sub 733 and E-2, Sub 763 and E-2, Sub 760.

The Commission issued orders in Docket Nos. E-2, Sub 733 and E-2, Sub 763 which, taken together, authorize construction of 1280 MW of generating capacity in Richmond County and 480 MW of generating capacity in Rowan County.

The Commission issued an Order Granting Certificates dated November 2, 1999, in Docket No. E-2, Sub 733. This order granted certificates of public convenience and necessity to CP&L for construction of 800 MW of simple cycle combustion turbine generating capacity in Rowan County and 800 MW of simple cycle combustion turbine generating capacity in Richmond County. The order found as a fact that the new generating capacity was needed for both normal load growth within CP&L's territory and CP&L's contractual commitments to provide off-system wholesale power to NCEMC and Santee Cooper with reliability equal to that of retail customers.

The Public Staff expressed concerns in the Sub 733 proceeding as to CP&L's construction of capacity to serve off-system load and as to CP&L's contracting to provide native load priority off-system. The Public Staff recommended that the Commission's granting of the certificates should not indicate that the Commission would approve inclusion of the facilities in rate base and that ratemaking treatment of the facilities would be made when appropriate in the best interest of retail customers. In response to the concerns raised by the Public Staff, CP&L specifically committed in the Sub 733 proceeding that it "will not allow its retail electric customers to be disadvantaged in any manner, either from a quality of service or rate perspective, as a result of its participation in the wholesale power market." The Commission incorporated CP&L's commitment into an ordering paragraph of the Order Granting Certificates in Sub 733, and the Commission specifically found as a fact in that order that ratemaking treatment for the new facilities would be addressed in subsequent proceedings when cost recovery was sought by CP&L.

CP&L subsequently initiated Docket No. E-2, Sub 763, and the Commission issued an Order Approving Application in that docket on August 17, 2000, which allowed two of the five combustion turbines previously approved for Rowan to be moved from Rowan to Richmond and granted a new certificate for construction of a 160 MW heat recovery steam turbine to be added at the Richmond site. This order found that the new construction was needed for projected growth in demand from both retail customers and firm wholesale customers; and this order again found as fact that the granting of the certificate "does not constitute approval of inclusion of the facility's cost in rate base or operating expenses for ratemaking purposes." This order addressed the Public Staff's concerns in another way as well. The Sub 763 order required CP&L to provide quarterly reports and forecasts of upcoming wholesale sales to be made from system resources which would impact system reserve margins.

At about the same time, on August 22, 2000, the Commission included a condition in the order approving the CP&L-Florida Progress merger in Docket No. E-2, Sub 760, which required CP&L to give 20 days advance notice to the Commission and the Public Staff before executing any agreement for a wholesale sale at native load priority.

Thus, it is clear from the proceedings in these dockets that the Commission allowed construction of the facilities involved in the present proceeding to serve both retail and wholesale customers, that the Commission held concerns as to CP&L's new wholesale commitments, that CP&L committed and the Commission specifically provided that retail customers would not be disadvantaged as to either quality of service or rates by CP&L's wholesale commitments, and that the Commission took steps to monitor CP&L's future wholesale contracts more closely.

EVIDENCE AND CONCLUSIONS IN SUPPORT OF FINDINGS OF FACT NOS. 6 - 13

The evidence supporting these findings of fact is contained in the testimony and exhibits of CP&L witness Ingersoll, the testimony of CUCA witness O'Donnell, and the joint testimony of the Public Staff witnesses.

The Public Staff witnesses expressed concern as to the potential for CP&L's retail customers to experience decreased reliability as a result of CP&L's participation in the wholesale market. They testified that reliability for retail customers may suffer as more wholesale load obtains the same level of reliability as the current retail customers on CP&L's system. If CP&L continues to add new wholesale load with native load priority, CP&L is pledging a greater portion of its generating facilities to a larger body of customers, and thus potentially reducing the generating capacity available to its retail customers. The Public Staff witnesses also expressed concern as to the potential for excessive reserve margins and upward pressure on retail rates if CP&L builds facilities to supply new wholesale load and the wholesale load does not materialize or existing wholesale load does not renew its contracts with CP&L and leaves the CP&L system. The Public Staff testified that the separation of CP&L's retail and wholesale obligations was the driving factor in their analysis in these dockets.

CP&L witness Ingersoll testified that these concerns have led CP&L to propose that it begin separating its retail and wholesale businesses. To begin such a separation, CP&L proposed a number of things. CP&L proposed to assign the unit sales contracts that it currently has regarding the Rowan generating facilities to a new affiliate. Further, CP&L will not seek to renew any off-system native load wholesale contracts when they expire. Both these unit sales contracts and these off-system native load firm wholesale contracts will become the responsibility of the new affiliate. Finally, CP&L will transfer some of its generating assets to this new affiliate. Witness Ingersoll testified that the Richmond and Rowan facilities would be appropriate resources to transfer to the new affiliate since they have not been included in CP&L's rate base and since they are the units most directly associated with CP&L's new wholesale load.

Witness Ingersoll testified that the Rowan County combustion turbines are already dedicated to serving wholesale load, or will be in the very near future. Thus, their transfer to a CP&L affiliate, where they will continue to serve wholesale load, will have no resulting impact on CP&L's resource plans and reserve margins.

The CP&L witnesses also proposed to transfer away the entire Richmond facility to a new affiliate. Witness Ingersoll testified that CP&L knows for sure that it will lose 650 MW of off-system wholesale load in 2004, and in addition, he stated that over 1800 MW of on-system wholesale load may choose another supplier in 2004. Therefore, he submitted that transferring the entire Richmond facilities, which will be approximately 1200 MW, "strikes a good balance between the worst case and base case scenarios of losing the entire 2300 MW and only losing the 650 MW of off-system load."

CP&L witnesses Ingersoll and Smith testified that Progress Energy Ventures is attempting to put in place a financing plan for the Richmond and Rowan facilities and for other gas-fired generating projects to be constructed during the time frame 2001 through 2004 and that it costs less to have one financing, rather than multiple, smaller financings. CP&L witness Smith testified that lenders consider the total value of assets available as security to the lender, the geographical diversity of such assets, and the creditworthiness of purchasers of the output. The inclusion of all the Richmond generating facilities is important in the overall financing because it enhances the factors the lenders assess, thus helping to lower the financing cost. Progress Energy Venture's Georgia generating project, the Rowan facilities, and the Richmond facilities will, together, allow Progress Energy Ventures to achieve a critical mass of assets and to negotiate favorable financing terms for Progress Energy Ventures. Witness Ingersoll testified that interest rates are at an attractive level and that time is of the essence. Ingersoll testified that another reason the entire Richmond facility needs to be transferred is that, operationally and logistically, the entire plant needs to be under common ownership and control, so that all support services and decision-making are centralized.

In order for the Richmond facilities to continue to be available to CP&L to meet the needs of its retail and wholesale customers, Ingersoll proposed use of a buyback agreement, also known as a tolling agreement, that would be entered into between CP&L and Richmond County Power Company, LLC. The tolling agreement would be for a term of 5 years with two renewal options of 3 years each. Ingersoll testified that the tolling agreement would replicate the cost that CP&L would have incurred had the transfer not taken place. According to Ingersoll, through at least 2004, the only cost to CP&L's customers would be the fuel cost, which will be the same fuel cost that CP&L would have incurred had it retained these facilities. The buyback agreement would be approved by the Federal Energy Regulatory Commission and this Commission pursuant to G.S. 62-153. Finally, Ingersoll testified that CP&L's customers will benefit since the risk of these assets being uneconomic is transferred to an unregulated affiliate. He testified that CP&L's retail customers will have the facilities available to them to ensure the provision of reliable service at the same cost that would have been incurred had the transfer not occurred, and they will have the opportunity to either keep or discard the facilities depending upon load growth and the availability of alternative resources in the wholesale market at the dates of the options.

CP&L's Code of Conduct approved in Docket No. E-2, Sub 753, requires that the transfer price for non-tariffed goods or services provided by CP&L to a non-regulated affiliate be the higher of market value or fully distributed cost. CP&L witness Ingersoll testified that the most appropriate value at which to transfer the Richmond and Rowan facilities is their net book cost since this is known and verifiable while a market valuation will be based on numerous assumptions and long-term projections.

The Public Staff witnesses testified that the Richmond facilities will be available exclusively to CP&L for the term of the tolling agreement, depending upon CP&L's needs. In addition, CP&L committed to the Public Staff that it will not actively pursue off-system wholesale loads once these generation facilities are transferred to the new affiliates. The Public Staff witnesses testified that when additional capacity is needed by CP&L, CP&L has committed that it will look at both outside energy sources and self-build options and select the appropriate type and amount of capacity to maintain reliable electric service at reasonable rates. The Public Staff witnesses further testified that certain safeguards should be established including: (1) that the electricity provided by the Richmond facilities should be exclusively under the control of CP&L in the amount necessary to reasonably and adequately supply CP&L's load; (2) that CP&L should have sufficient flexibility to release any unneeded capacity at Richmond if retention of such capacity would place a burden on CP&L's customers; (3) that before CP&L releases any capacity at the Richmond facilities, it should notify the Commission and the Public Staff sufficiently in advance so the Commission can review the basis for such action; (4) that the cost of power from the Richmond facilities should be no greater than the cost of power from the Richmond facilities without the transfer; (5) that the financing of these facilities by a CP&L affiliate should have no adverse impact on CP&L's retail customers; and (6) that all appropriate costs should be charged to the new affiliates and the appropriate entries should be made on CP&L's books to reflect the value of the assets that are transferred. The Public Staff witnesses testified that they were satisfied that the proposed tolling agreement gives CP&L the control and flexibility that it needs to manage its system resource requirements sufficiently and effectively.

The Public Staff witnesses testified that they had begun to analyze a study of the market value of the Rowan facilities conducted by CP&L but needed additional time to evaluate the methodology and the results once final cost information becomes available. Public Staff witness Cox indicated that the Public Staff does not object to recording the transfer of the Rowan facilities at cost until the Public Staff has completed its analysis of the study, subject to any changes that the Commission finds appropriate. She stated that the Public Staff does not object to an exception to the Code of Conduct for the transfer of the Richmond facilities at cost because CP&L will be buying the power back at cost during the term of the buyback agreement. The Public Staff witnesses identified four issues relating to the proposed transfers which they wanted to preserve for further evaluation: (1) the appropriate compensation to be recorded by CP&L for the transfer of the Rowan facilities to Progress Energy Ventures, as just discussed; (2) the reasonableness of the decision for CP&L to purchase capacity and energy through the tolling agreement from the year 2003; (3) the price of capacity to be paid by CP&L to Richmond County Power, LLC pursuant to the tolling agreement; and (4) the transfer pricing and other provisions of the service agreement to be entered into by CP&L and Progress Energy Ventures with regard to the provision of services by CP&L to the Rowan facilities.

CUCA witness O'Donnell testified that the regulated CP&L had procured an asset at below its current market price and was attempting to shift this low cost asset to its unregulated subsidiary Progress Energy Ventures. He testified that this would be a good business move for CP&L but would not be fair to retail consumers. He testified that if the Richmond and Rowan facilities are transferred at cost and cost is actually below market value, consumers will be required to pay higher rates in the future if CP&L needs additional generating assets to replace the transferred assets. Finally, he testified that it appears from CP&L's IRP that it will need additional generating capacity in the next 4 to 6 years.

Following the hearing, CP&L and CUCA entered into discussions and reached certain agreements regarding CP&L's exercise of the options in the buyback agreement. These agreements were set out in a letter filed by CP&L in these dockets on August 9, 2001. In light of these agreements, CUCA does not oppose the transfer of the Richmond and Rowan generating facilities.

The Commission has considered all of the testimony and exhibits presented herein, and the Commission has applied the standard of whether the proposed transfers are justified by the public convenience and necessity. G.S. 62-111(a). The Commission concludes that the transfer of the

Rowan certificate and facilities should be approved, but the Commission is not convinced on the basis of the present evidence that the transfer of the Richmond certificate and facilities should be approved at this time. The Commission reaches these conclusions based on the following reasons.

The Commission agrees that CP&L's increased participation in the wholesale market exposes retail ratepayers to new risks and complicates the utility's planning to serve its retail load. In previous orders, the Commission has already expressed concerns about the implications of CP&L's increased participation in the wholesale market. The Commission agrees that it is reasonable and in the best interests of retail ratepayers for CP&L to begin to separate its retail and wholesale obligations, so long as the transfer of generating facilities is accompanied by a related transfer of wholesale obligations or retail ratepayers are protected and made whole for the loss of access to the generating facilities transferred. However, the Commission recognizes that this separation cannot be achieved at once. CP&L witness Ingersoll testified that since there is so much wholesale load under contract, "it will take time and there are many other issues that need to be addressed." A Public Staff witness testified that "it's going to take some time to get down to where CP&L regulated is [sic] almost no wholesale customers. It may never happen, it may happen in two years, but we're moving in that direction." The Commission agrees with the move toward separation, but the transition must be made in smooth and measured steps. Separation of retail and wholesale is not an end in itself. Separation is a means of protecting retail ratepayers, and the move toward separation must be made with this in mind.

When the Commission granted the certificates of public convenience and necessity at issue herein to CP&L in 1999, the Commission found a need for the facilities based on both normal retail load growth and contractual commitments to provide wholesale service. The Rowan facilities are associated with unit sales wholesale contracts which can be transferred to a new affiliate at the same time that the facilities themselves are transferred, leaving no impact on reserve margins or resource plans. The Commission concludes that this is a reasonable move toward separation of retail and wholesale obligations and that this move can be made at this time in the public interest.

This is not the case with the Richmond facilities. The Richmond facilities were built to serve both retail and wholesale load, but the wholesale contracts associated with these facilities are native load priority contracts which cannot be transferred away from CP&L to a new affiliate at this time. The proposed transfer of the Richmond facilities is therefore, at best, poorly timed since it does not coincide with the shedding of wholesale obligations by CP&L. To the extent CP&L must keep these existing wholesale obligations, CP&L should also retain the facilities that were just recently justified and built to help serve these obligations.

CP&L's solution to transferring the Richmond facilities while retaining the associated wholesale obligations is a buyback agreement, but the Commission is not persuaded, based on the present record, that this is sufficient to protect ratepayers and make them whole. CP&L proposes to transfer away facilities with a 25-year life and to buy back from the same facilities for a maximum of 11 years (a 5-year term and two renewal options of 3 years each). The goal is to buy back at the same cost as if CP&L had retained the facilities for the term involved. At the time of the hearing in these dockets, only a draft of the buyback agreement was available. After the record in these dockets was closed, the buyback agreement was filed for Commission approval as an affiliate contract in Docket No. E-2, Sub 786. The Commission has taken no action in the Sub 786 docket yet. Most importantly, the buyback agreement represents a wholesale transaction and, as such, is ultimately subject to the jurisdiction of FERC. CP&L witness Ingersoll testified that the agreement "has to pass muster at the FERC in terms of being in line with their guidance..." He testified that the agreement had been filed with FERC but he did not know the status of the proceedings there. The buyback may represent some loss of Commission jurisdiction in favor of FERC jurisdiction. Further, it is clear from CP&L's IRP filings that CP&L's retail load is growing and that CP&L projects a need for additional generation by the time the buyback term and options expire. Witness Ingersoll's Exhibit 4, CP&L's revised IRP, projects a need for 2551 MW of new capacity before 2010, after shedding the Rowan and Richmond facilities. The plan calls for 1280 MW of simple cycle combustion turbine and 2000 MW of combined cycle generation by 2010. Witness Ingersoll testified that no site has been chosen for this generation and that he did not know if CP&L would build or purchase this capacity. The Public Staff witnesses testified that they didn't know whether this new generation would be more or less expensive than the Rowan and Richmond facilities. What is known is that the turbines installed at the Rowan and Richmond facilities were purchased at good prices, some below the current market prices of such turbines; that the Rowan and Richmond sites are desirable sites that were acquired and developed with CP&L utility resources; and that the sites enjoy transmission access, natural gas supply, water, transportation, and environmental approvals. The proposed transfer of the Richmond facilities represents a transfer of a known, valuable utility asset together with a FERC-jurisdictional buyback agreement of a limited term, at the end of which CP&L projects a need for additional capacity at a cost now unknown.[1] The Commission would need more convincing evidence than presented herein to approve such a transfer.

Many of the reasons cited by CP&L in support of transferring all of the Richmond facilities to the new affiliate at this time concern advantages that the transfer will bring to the affiliate. CP&L witnesses testified that the Richmond transfer will give this affiliate a large asset base and enable it to arrange favorable financing for this and other projects of the affiliate. The Commission approaches the proposed transfers from the perspective of whether they are justified by the public convenience and necessity from the standpoint of retail ratepayers and the regulated public utility, not whether they serve the interests of a new unregulated affiliate.

From the standpoint of ratepayers, the primary benefits cited by CP&L are that ratepayers will be protected from possible impacts on reliability and from possible excess capacity. The Commission is not convinced that these risks are substantial enough to outweigh the new risks posed by the proposed transfer. In the first place, it is important to note that the risks to ratepayers now cited by CP&L, quality of service and rates, are the very same risks from which CP&L itself has already promised to protect its ratepayers. In Docket No. E-2, Sub 733, when seeking the certificates at issue here, CP&L specifically committed that it "will not allow its retail electric customers to be disadvantaged in any manner, either from a quality of service or rate perspective, as a result of its participation in the wholesale power market." Next, the Commission notes that it has already required advance notice of new wholesale commitments by CP&L, so the Commission and Public Staff can better monitor any potential impact on reliability. As to the risk of excess capacity, this

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[1] While both sites represent valuable utility assets, the Commission will approve the transfer of the Rowan facilities since, as previously explained, these facilities are associated with contracts that can be transferred along with these facilities and since the Rowan transfer promotes the separation of retail and wholesale to the extent reasonable at this time.

assumes that CP&L loses substantial wholesale load. Although CP&L witness Ingersoll pointed out that over 2300 MW of wholesale contracts will expire in 2004, there is simply no evidence as to whether or not this wholesale load (absent the 650 MW of off-system load that will be lost for sure) is likely to be retained or replaced with new wholesale load. Finally, excess capacity would only impact retail rates if a rate case is held. Another benefit to retail ratepayers cited by CP&L is that the economic risks of these facilities will be transferred away from the retail ratepayers. While this is true, it is also true that the Richmond transfer would pose new risks for retail ratepayers, including the economic risks of the incremental capacity that CP&L projects it will need when the buyback expires.

The Commission is not convinced that the transfer of the entire Richmond facilities strikes a good balance between the possible loss of a wholesale load ranging between 650 MW and over 2300 MW in 2004, as testified by CP&L witness Ingersoll. The Richmond facility will be approximately 1280 MW, but Progress Energy Ventures proposes to build additional generation at the Richmond site, for a total capacity of about 1920 MW at build-out. Although CP&L's testimony raised concerns about excess capacity if CP&L loses wholesale load, the Commission notes that Progress Energy Ventures is willing to assume ownership of the Richmond facilities and to expand their capacity to approximately 1920 MW.

The facts in these dockets are complicated, and the interests are often conflicting. The Commission recognizes that additional generation has been proposed for the two sites by Progress Energy Ventures in Docket EMP-5, Sub 0, and the testimony in that docket is that the new construction is dependent on the transfers being allowed in the present dockets. The present decision has been a difficult one, but it represents the best judgment of the Commission as to the public interest.

In summary, the Commission will approve the proposed transfer of the Rowan facilities, together with the transfer of the unit sales contracts associated with these facilities. With regard to the transfer price for the Rowan facilities, the initial value at which the Rowan generating facilities shall be transferred to Rowan County Power, LLC, shall be their net book cost but the Commission will reserve a final decision on this matter until the Public Staff has completed its review and analysis of CP&L's market valuation study associated with these facilities. With regard to the service agreement to be entered into by CP&L and Progress Energy Ventures whereby CP&L will provide services to the Rowan County facilities, the Commission will address that issue when the service agreement is filed with the Commission for approval pursuant to G.S. 62-153. The Commission will not approve the proposed transfer of the Richmond facilities at this time based on the evidence in this record. As explained above, the Commission is not convinced on this record that the Richmond transfer and buyback is in the public interest. This decision is without prejudice to CP&L's ability to renew the request to transfer the Richmond facilities in light of changed circumstances.

IT IS, THEREFORE, ORDERED as follows:

1. That the petition to transfer the certificates of public convenience and necessity granted to CP&L in Docket Nos. E-2, Sub 733 and E-2, Sub 763 for the Rowan County generating facilities, and the facilities being constructed by CP&L in accordance with such certificates, to Rowan

County Power, LLC, is hereby approved together with the transfer of the unit sales contracts associated with these facilities;

2. That the initial value at which the Rowan generating facilities shall be transferred to Rowan County Power, LLC, shall be their net book cost, subject to adjustment if the Commission, upon completion of the Public Staff's analysis of CP&L's market valuation study, determines that the market value of the facilities at transfer exceeded net book cost; that CP&L shall provide upon request by any party to this proceeding all information necessary to verify the value at which the Rowan generating facilities were transferred; and

3. That the appropriate terms and rates to be included in the service agreement pursuant to which CP&L will provide services to the Rowan County generating facilities will be addressed in a subsequent proceeding under G.S. 62-153.

ISSUED BY ORDER OF THE COMMISSION.
This 1st day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg100101.01

Commissioners Richard Conder and Robert V. Owens, Jr. dissent in part.

DOCKET NO. E-2, SUB 778
DOCKET NO. EMP-5, SUB 1

COMMISSIONER CONDER, DISSENTING IN PART: I respectfully dissent from the majority of my colleagues in this case in that I would have approved Carolina Power & Light Company's (CP&L's) request to transfer both the Rowan and Richmond County facilities to Progress Energy Ventures. I do not believe there is a proper legal basis for the majority's decision in this matter. I do not believe the partial transfer, as allowed by the majority, is supported by competent, material and substantial evidence in view of the entire record as submitted. While I refrain from characterizing the majority's decision as arbitrary and capricious, I do believe that it is based not on the evidence in the record, but rather on speculation about "possibilities" that might exist in the future.

The transfer proposed by CP&L in this case has not been objected to by any party, including the Public Staff, the Attorney General, CUCA, and CIGFUR, which filed only "concerns" which they asked the Commission to consider. Yet, despite this overwhelming support, the majority, without any real basis, denies the transfer of the Richmond County facilities.

The Public Staff has expressed in this and earlier cases the concern that CP&L's participation in the wholesale market potentially exposes CP&L's retail customers to either insufficient reserves or excessive reserves and increased rates. I agree with the majority that it is reasonable for CP&L to begin separating its retail and wholesale businesses. Unlike the majority, however, I agree with the parties that the proposed transfer is prudent, that the amount of generation resources proposed to be transferred is reasonable given the potential loss of 2300 MW of wholesale load in the year 2004, and that the specific generation resources to be transferred are the Rowan and Richmond County facilities recently certificated by the Commission. To allay any concerns, CP&L has proposed a tolling agreement which, together with the safeguards proposed by the Public Staff, will allow the Richmond County facilities to continue to be available to CP&L to reliably and cost-effectively meet the needs of its retail and wholesale customers for a number of years. As CP&L's witnesses testified, the transfer of the Richmond County facilities and the adoption of the tolling agreement is actually beneficial to CP&L's ratepayers and provides them with the best of both worlds: they will have a resource available to them to ensure the provision of reliable service at the same cost that would have been incurred had the transfer not occurred, and they will have the opportunity to either keep or discard the units depending upon load growth and the availability of alternative resources in the wholesale market at later dates.

I also note that the Commission has been directed to encourage merchant plant development in this State. For example, at the urging of the Legislative Study Commission on the Future of Electric Service in North Carolina, the Commission earlier this year re-evaluated and streamlined its procedures for certificating electric generating facilities to be operated as merchant plants. Yet, in this case, the majority is denying a request for one of our own utilities to build merchant plants which I believe will result in a more robust wholesale electric market and lower prices to North Carolina consumers.

In summary, the Commission is required to approve CP&L's proposal to transfer to affiliates both the Rowan and Richmond County generating facilities if it is in the public interest. Given the concerns expressed by the Public Staff with regard to CP&L's participation in the wholesale market, the potential loss of up to 2300 MW of wholesale load by the year 2004, and CP&L's commitment that it will not seek to renew the off-system wholesale contracts totaling 650 MW or the unit sale contacts associated with the Rowan County generating facilities, I believe that the proposed transfer properly shifts the risks of CP&L's participation in the wholesale market from CP&L's retail ratepayers to its shareholders, is in the public interest, and should, therefore, be approved.

/s/ J. Richard Conder
COMMISSIONER J. RICHARD CONDER

DOCKET NO. E-2, SUB 778
DOCKET NO. EMP-5, SUB 1

COMMISSIONER OWENS, DISSENTING IN PART: I join Commissioner Conder in respectfully dissenting from the majority. I, too would have approved Carolina Power and Light Company's request to transfer both the Rowan and Richmond County facilities to Progress Energy Ventures, and for many of the same reasons. I believe the majority's decision is arbitrary and capricious.

We are not required to divorce ourselves from our reason and common sense when deciding matters before us, nor are we required to ignore our life experience and general knowledge. Indeed, we are appointed and confirmed to this body because of our training, experience, knowledge and judgment. We must apply reason, common sense, life experience and general knowledge to every decision we make. These factors informed the law as it was being made and it must inform the law and it is being interpreted and applied.

The decision reached by the majority in this case defies reason and common sense. It contradicts lessons we have learned in California and elsewhere; and it is contrary to the plain intent of our legislative leaders who are heavily involved in electric generation in North Carolina. The decision is based upon whim and speculation and substitutes bureaucratic suspicion for sound business judgment. As Commissioner Conder points out, the majority is the ONLY party to this case to object to the transfer.

There is virtually universal agreement that a robust wholesale electric market is essential for the proper functioning of our system of generating and delivering electricity. Our legislators have told us in no uncertain terms that they want to encourage the development of generating plants in North Carolina. We should have learned from California that we need to stay ahead of the electricity demand curve to keep the markets stable and affordable. Having the risk of such development, particularly the risk of developing excess supply borne by shareholders instead of retail rate payers makes logical public policy sense as well as business sense. We not only do not encourage generation development with this decision, we directly inhibit that development at the Richmond County site and indirectly inhibit it elsewhere.

Consideration of the public interest cannot be done in a vacuum. The consideration reaches beyond CP&L's retail customers; it reaches to their wholesale customers and to the public at large. All factors should be taken into account, not the least of which is the effect of our decision upon economic development, particularly in economically deprived counties. This decision effectively deprives a needy North Carolina county of several hundred million dollars in new economic investment. That does immediate harm to the public interest under the guise of protecting the public interest from speculative and uncertain harm in the future.

I agree with CP&L's witnesses and Commissioner Conder that the transfer of the Richmond County facility would actually be beneficial to their ratepayers, providing them with the benefit of the additional resources while removing from them the risk. There are more than ample protections already built into the Code of Conduct and other agreements or commitments. This decision provides no more protection while causing immediate harm. It is not in the public interest.

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

DOCKET NO. E-7, SUB 700

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Duke Energy Corporation	)	
for Authorization under G.S. Section 62-161	)	ORDER ON PUBLIC STAFF
To Issue Common Stock in Connection with	)	MOTION FOR ORDER
the Acquisition of Westcoast Energy, Inc.	)	DIRECTING AMENDMENT

BY THE COMMISSION: On October 10, 2001, Duke Energy Corporation (Duke) filed an application for authority to issue shares of common stock in connection with the acquisition of Westcoast Energy, Inc. (Westcoast). Duke filed this application pursuant to G.S. 62-161, which provides that no public utility shall issue any securities unless and until the Commission authorizes such issuance. G.S. 62-164 provides that all applications for the issuance of securities shall be disposed of within 30 days after filing, unless it is necessary for the Commission to continue consideration of the application for good cause, in which case the Commission must issue an order stating the facts necessitating the continuance.

Although Duke's application states that the issuance of securities is in connection with the acquisition of Westcoast, Duke did not file an application pursuant to G.S. 62-111. G.S. 62-111(a) reads as follows:

> No franchise now existing or hereafter issued under the provisions of this Chapter other than a franchise for motor carriers of passengers shall be sold, assigned, pledged or transferred, nor shall control thereof be changed through stock transfer or otherwise, or any rights thereunder leased, *nor shall any merger or combination affecting any public utility be made through acquisition of control by stock purchase or otherwise,*[1] except after application to and written approval by the Commission, which approval shall be given if justified by the public convenience and necessity. Provided, that the above provisions shall not apply to regular trading in listed securities on recognized markets. (Emphasis added.)

On October 15, 2001, the Public Staff filed a motion requesting that the Commission order Duke to amend its application to include a request for approval pursuant to G.S. 62-111(a) and to comply with the filing requirements set forth in the Commission's Order of November 2, 2000, in Docket No. M-100, Sub 129, or seek waiver of the requirements. The motion states that Duke has

[1] The Lexis complication of the General Statutes erroneously reads "nor shall any merger or combination affecting any public utility be made through acquisition or control by stock purchase or otherwise." It should read "nor shall any merger or combination affecting any public utility be made through acquisition of control by stock purchase or otherwise." See Session Laws, 1963, Chapter 1165, Section 1. (Emphasis added.)

taken the position in discussions with the Public Staff that G.S. 62-111(a) does not apply here; however, the Public Staff contends that the statute applies to all cases in which a merger or business combination affects a public utility under the Commission's jurisdiction. The Public Staff cites previous Commission proceedings as to the Duke-PanEnergy merger and the Dominion Resources-Consolidated Natural Gas merger.

On October 10, 2001, Duke filed a response arguing that G.S. 62-111(a) does not apply to the Westcoast transaction. First, Duke provides the essential elements of the Westcoast transaction. A wholly owned subsidiary of Duke will acquire all of the outstanding shares of Westcoast common stock in exchange for cash and Duke common stock with an aggregate value of approximately $3.5 billion. The Duke stock to be issued in this transaction will increase Duke's outstanding shares by approximately 6%. Westcoast will survive the transaction as a wholly owned subsidiary of Duke and any outstanding preferred stock or long-term debt of Westcoast would not be assumed or guaranteed by Duke. The management of Duke will not change and Duke will continue to be a North Carolina corporation. Duke will also continue, through its Duke Power division, to own and operate under its North Carolina public utility franchises. Although the Westcoast transaction will not require a vote of Duke's shareholders, Duke will file a Registration Statement with the SEC with respect to certain of its securities issued in the transaction and will seek authority to issue its securities from the North Carolina Utilities Commission and the South Carolina Public Service Commission. Duke may also seek approval of the transaction by FERC pursuant to Section 203 of the Federal Power Act. The transaction will require the affirmative votes of two-thirds of the voting power of Westcoast's shareholders and will require approval of certain Canadian authorities.

Based upon the elements of this acquisition, Duke argues that G.S. 62-111(a) does not apply since the phrase "through acquisition of control by stock purchase or otherwise" refers to control of the public utility that holds the franchise. According to Duke, the statute is intended "to prevent a franchise from coming into the hands of, or under the control of, an entity that is unable or unfit to continue reliable service at reasonable rates." Here, the Westcoast acquisition does not result in any change of control of Duke, and therefore, Duke argues, the statute does not apply. Duke argues that the Public Staff would apply the statute to any combination that in any way affects a public utility and that this would lead to absurd results in very small transactions. As to the Public Staff's reference to Duke's own decision to file for approval under G.S. 62-111(a) for its merger with PanEnergy, Duke submits that this is a bootstrap argument, that a utility may have reasons to file under the statute in one case but not another, and that its voluntary decision to file as to PanEnergy should not be regarded as a binding precedent for future situations. Finally, Duke argues that the Public Staff's interpretation of the statute would render it unconstitutional under the Commerce Clause of the United States Constitution since it would extend the reach of the statute beyond any reasonable or legitimate state interest and would result in a substantial burden on interstate commerce. Duke cited the decision of the North Carolina Supreme Court in State ex rel Utilities Commission v. Southern Bell, 288 N.C. 201, 212 S.E.2d 543 (1975). Duke contends that the same conditions cited in that case exist here since Duke is regulated in North Carolina and South Carolina and its energy operations are worldwide in scope with less than 8% of its total consolidated revenues coming from its North Carolina retail operations.

On October 26, 2001, Duke filed an affidavit of Vice President and General Counsel Paul R. Newton setting forth information regarding the Westcoast acquisition and Duke's overall operations throughout the United States and the world. He asserts that future acquisitions by Duke are highly likely given the current climate of increasing globalization and consolidation in energy markets and Duke's position as a leading player in these markets.

On October 26, 2001, the Public Staff filed a reply to Duke's response of October 10. The Public Staff again contends that the proper interpretation of G.S. 62-111(a) is "nor shall any merger or combination affecting any public utility be made through acquisition of control (of or by such public utility) by stock purchase or otherwise..." (Parenthetical and emphasis added.) The Public Staff argues that its interpretation is supported by recognized rules of statutory construction, is just as logical as Duke's interpretation, and is constitutional. Courts have long held that the interpretation of a statute by the officers charged with executing it, while not binding, is entitled to great consideration and should not be disregarded unless clearly erroneous. The Public Staff's interpretation of the statute has been accepted and applied by this Commission in the past, with tacit agreement of utilities including Duke, to several acquisitions by, and not of, a public utility. The Public Staff adds that this is appropriate since a merger can affect a utility regardless of whether the utility is the party being acquired or the party acquiring. For example, when a utility expands its operations through acquisitions, there is a risk that the Commission will lose at least some of its jurisdiction to the SEC or the FERC. Duke's interpretation could significantly erode the Commission's power to regulate public utilities in such cases. Although Duke contends that requiring approval under G.S. 62-111(a) would be an undue burden on interstate commerce, Duke has already filed for approval under G.S. 62-161. Finally, since Westcoast is a Canadian corporation, the Public Staff notes that there is no danger of conflicting regulation by different states. If the Commission requires Duke to file under G.S. 62-111(a), the Public Staff states that it will present the matter to the Commission with a favorable recommendation soon after the application is filed and will work with Duke and others on standards for future applications.

Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene and reply on October 26, 2001. The petition to intervene is allowed. In its reply, CUCA argues that a merger can affect a public utility even though less than 50% of its stock is purchased and that Duke's narrow interpretation of G.S. 62-111(a) would not protect ratepayers from dilution and alteration of a public utility's business. CUCA argues that an acquisition such as this one — where Duke will exchange more than 5% of its stock and an officer will be added to Duke's board of directors — affects the public utility, and that approval under G.S. 62-111(a) should be required. CUCA distinguishes the Southern Bell case cited by Duke, since that case interpreted G.S. 62-161, not G.S. 62-111(a).

The Commission has carefully considered all of the arguments presented herein. The Commission concludes that the Public Staff's motion should be allowed and that Duke should be required to file under G.S. 62-111(a) for several reasons. First, Duke's interpretation of G.S. 62-111(a) is at odds with the way the Commission has traditionally interpreted and applied the statute. Duke's interpretation would restrict the statute to a merger or combination that changes control of the utility. The Commission has always interpreted the statute as covering any merger or combination that affects the utility, whether the utility is the acquired or the acquiring company. Neither Duke nor any other utility within our institutional memory has ever presented this narrow interpretation of G.S. 62-111(a) before. Under Duke's interpretation, the Commission should not have held the proceedings to approve the Duke-PanEnergy merger (Docket No. E-7, Sub 596), the Dominion Resources-Consolidated Natural Gas merger (Docket No. E-22, Sub 380), or the CP&L Energy-Florida Progress merger (Docket No. E-2, Sub 760), some of the most important proceedings to come before the Commission in recent years. It is significant that all of the utilities in these proceedings, including Duke, filed under G.S. 62-111(a) without challenging the Commission's interpretation of the scope of the statute. Second, the Public Staff's motion will be allowed because the Public Staff's interpretation of G.S. 62-111(a) is correct and necessary for the Commission to perform its responsibilities. Duke posits the "obvious purpose" behind the statute — to prevent transfer of a public utility franchise to an unfit entity — and observes that this purpose supports its interpretation, but the Commission's responsibilities are broader than just control of franchise transfers. The Commission is responsible for ensuring reliable public utility service at reasonable rates. It is easy to imagine cases in which an acquisition by a public utility could jeopardize reliable service and reasonable rates, as surely as an acquisition of the utility itself. Loss of jurisdiction to other agencies, risky ventures that threaten the utility's ability to raise capital, and increased opportunities for affiliate dealings all come to mind as possibilities that the statute was intended to address. Third, the Public Staff's interpretation is more consistent with the language found in the statute. In the language of the provision — "nor shall any merger or combination affecting any public utility be made through acquisition of control by stock purchase or otherwise" — the key term is "affecting." The provision requires Commission approval of all mergers and combinations that affect a utility. Duke's interpretation limits application of this provision to a subset of all mergers and combinations that affect a utility: only those that affect the utility in a certain way — by changing control of the utility franchise — would be subject to Commission approval under Duke's interpretation. To get this result, Duke reads restrictive language (control "of the public utility that holds the franchise") into the statute, but this language is simply not there. If the General Assembly had intended to require approval of only those mergers that affect a utility by changing control of the utility franchise, it would have surely written this language into the statute, rather than leaving it for Duke to divine. Fourth, Duke's restrictive interpretation of the "any merger or combination..." provision would essentially render the provision surplusage. If, as Duke argues, the "any merger or combination..." provision is only intended to provide oversight of the alienation of a utility franchise, the provision would not be necessary since the statute already provides, in earlier language, that "No franchise...shall be sold, assigned, pledged or transferred, not shall control thereof be changed through stock transfer or otherwise..." except upon Commission approval. Any merger or combination that changes control of a utility would necessarily change control of the utility's franchise, and so the two provisions would be duplicative if the "any merger or combination..." provision is as restrictive as Duke contends. The Commission does not believe that the General Assembly was merely repeating itself with the "any merger or combination..." provision. The Commission believes that this provision covers more than just the transfer of a utility franchise and that G.S. 62-111(a) is broader than interpreted by Duke. Finally, there is Duke's claim that the Public Staff's interpretation would render G.S. 62-111(a) unconstitutional. The Commission has no jurisdiction to determine the constitutionality of a statute. State ex rel. Utilities Comm. v. CUCA, 336 N.C. 657, 673-4 (1994). The Commission must interpret the statute according to its terms and in light of the regulatory responsibilities assigned to the Commission, and we have done that. In conclusion, the Public Staff's interpretation of G.S. 62-111(a) is more consistent with the language and purpose of the statute than that advanced by Duke, is necessary for the Commission to exercise its responsibilities under law, and has been followed by the Commission and parties, including Duke, for years.

The Commission will allow the Public Staff's motion and require Duke to file for approval of the Westcoast acquisition under G.S. 62-111(a). Duke must also comply with the filing requirements set forth in the Commission's Order of November 2, 2000, in Docket No. M-100, Sub 129, or seek waiver of the requirements. Duke may request a waiver, but it has not yet done so in any of its filings. In light of the requirement that a further filing as to the Westcoast acquisition must be made, the Commission finds good cause to continue its consideration of the application for issuance of securities filed by Duke under G.S. 62-161 beyond the 30 days provided in G.S. 62-164, because the securities issue is contingent upon the proposed acquisition being approved, i.e., the merger and the issuance of these securities are inextricably linked, and more than 30 days will be required to receive and act upon Duke's application for approval of the acquisition under G.S. 62-111(a).

Finally, the Commission encourages the Public Staff to meet with Duke and other interested parties to discuss whether additional guidelines for future applications are appropriate.

IT IS, THEREFORE, ORDERED as follows:

1. That the motion filed by the Public Staff on October 15, 2001, should be, and hereby is, allowed and Duke is required to file for approval of the Westcoast acquisition under G.S. 62-111(a);

2. That Duke shall comply with the filing requirements set forth in the Commission's Order of November 2, 2000, in Docket No. M-100, Sub 129, or seek waiver of the requirements; and

3. That consideration of the application for issuance of securities filed in this docket by Duke under G.S. 62-161 should be, and hereby is, continued beyond the 30 days provided in G.S. 62-164 because the proposed securities issue is contingent upon the proposed acquisition being approved and more than 30 days will be required to receive and act upon Duke's application for approval of the acquisition under G.S. 62-111(a).

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg110601.01

Chair Jo Anne Sanford and Commissioner Judy Hunt did not participate.

DOCKET NO. EMP-3, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Rowan Generating Company,	)	
LLC for a Certificate of Public Convenience	)	ORDER GRANTING CERTIFICATE
and Necessity to Construct a Generating	)	
Facility in Rowan County, North Carolina	)	

HEARD ON: Wednesday, August 8, 2001, at 10:00 a.m. in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Judy Hunt, Robert V. Owens, Jr., Lorinzo L. Joyner, and James Y. Kerr, II

APPEARANCES:

For Rowan Generating Company, LLC:

Alexander P. Sands, III and Mary Lynne Grigg, Womble Carlyle Sandridge & Rice PLLC, Suite 2100, 150 Fayetteville Street Mall, Post Office Box 831, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Vickie L. Moir, Staff Attorney, Public Staff – N.C. Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

Margaret A. Force, Assistant Attorney General, N.C. Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

For Carolina Utility Customers Association, Inc.:

James West, West Law Offices, PC, Suite 1735, 434 Fayetteville Street Mall, Raleigh, North Carolina 27602

For Carolina Power & Light Company and Progress Energy Ventures, Inc.:

Len S. Anthony, Post Office Box 1551, Raleigh, North Carolina 27602

BY THE COMMISSION: On March 8, 2001, in Docket No. E-60, Sub 0, Entergy Power Generation Corporation (EPGC), an indirect subsidiary of Entergy Corporation (Entergy), filed preliminary plans for an electric generating facility as required by Commission Rule R8-61 and, at the same time, a request for waiver of the 120-day prefiling requirement contained in Rule R8-61. On

March 21, 2001, the Public Staff filed a response in which the Public Staff expressed support for a waiver. On March 27, 2001, the Utilities Commission entered an Order in which the Commission redesignated this proceeding as Docket No. EMP-3, Sub 0, and allowed the requested waiver of the prefiling requirement of Commission Rule R8-61.

On May 10, 2001, Rowan Generating Company, LLC (Rowan Generating), a subsidiary of EPGC, filed an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1, in which it requested the Commission to authorize construction of an approximately 900-megawatt, simple-cycle combustion turbine electric generating facility to be located in Rowan County, North Carolina. On the same date, Rowan Generating filed the testimony of Thomas M. Cornell, Jolecia Marigny, and J. Bradley Williams in support of the application.

On May 23, 2001, the Public Staff filed a notice of completeness indicating that the application complied with requirements of Commission Rule R8-63 and that it should be set for hearing pursuant to G.S. 62-82. On June 5, 2001, the Commission entered an order in which the Commission set Rowan Generating's application for hearing, required Rowan Generating to provide appropriate public notice, established deadlines for the filing of intervention petitions and the submission of intervenor testimony and rebuttal testimony, and required the parties to comply with certain discovery deadlines.

On July 10, 2001, Rowan Generating filed an affidavit of publication indicating that public notice had been provided as required. On May 17, 2001, Carolina Power and Light Company and Progress Energy Ventures, Inc. (CP&L), filed a petition to intervene. On May 25, 2001, the Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene. On June 1, 2001, the Commission allowed the petitions of CP&L and CUCA. On July 18, 2001, Piedmont Natural Gas Company, Inc. (Piedmont), filed a petition to intervene. The Commission allowed Piedmont's intervention on August 7, 2001. On July 19, 2001, Roy Cooper, Attorney General, filed a notice of intervention. The intervention and participation of the Attorney General is recognized pursuant to G.S. 62-20. The intervention and participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On July 19, 2001, the Public Staff filed the testimony of Sami M. Salib. On July 30, 2001, Rowan Generating filed the rebuttal testimony and exhibits of their witness Williams. No other party submitted prefiled testimony in this proceeding.

The hearing was held as scheduled. Randy Harrell, Executive Director of the Salisbury-Rowan Economic Development Commission, testified as a public witness and requested that the Commission grant the certificate as requested. At hearing, the parties advised the Commission that they had reached a settlement with respect to all matters at issue in this proceeding.

On August 15, 2001, Rowan Generating and CP&L filed a joint letter as verification that as of August 7, 2001, CP&L and EPGC entered into a memorandum of understanding in which CP&L agreed to grant to EPGC, for valuable consideration, an electric transmission easement for transmission interconnection access from the facility to Duke Electric Transmission's Woodleaf switchyard and to grant a permanent gas pipeline easement across a separate portion of CP&L's property.

ELECTRIC MERCHANT PLANT - CERTIFICATE

Based on the testimony presented at the hearing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Entergy, headquartered in New Orleans, Louisiana, is a major global energy company with power production, distribution operations and related diversified services. Entergy is among the largest U.S. utility companies and is one of the largest operators of gas-fired generation.

2. Rowan Generating is a limited liability company organized under the laws of Delaware with its principal place of business in The Woodlands, Texas. The company is a single-purpose company formed to continue and complete the development and operation of the proposed Rowan generating facility. Rowan Generating is an indirect subsidiary of Entergy and a direct subsidiary of EPGC.

3. In compliance with G.S. 62-110.1 and Commission Rule R8-63, Rowan Generating properly filed with the Commission its application for a certificate of public convenience and necessity in which it requested the Commission to authorize the construction of an approximately 900-megawatt natural gas-fired combustion turbine electric generating facility to be located in Rowan County, North Carolina.

4. The certificate should be conditioned upon Rowan Generating's abstaining from attempting to exercise any power of eminent domain as it relates to this proposed facility.

5. The Commission identified a number of conditions that apply to merchant plant certificates in Rule R8-63(e) and (f). These conditions are relied upon by the Commission in its determination that the public convenience and necessity are served by the construction of this proposed facility.

6. Rowan Generating has made a sufficient showing of need for this proposed facility based on the anticipated growth in peak demand expected in the Southeast Reliability Council (SERC) region, including North Carolina.

7. It is reasonable and appropriate to grant the requested certificate as conditioned herein.

8. EPGC and CP&L executed a memorandum of understanding by which CP&L agreed to grant Rowan Generating, for valuable consideration, an electric transmission easement for transmission interconnection access from the Entergy property to Duke Electric Transmission's Woodleaf switchyard and a permanent gas pipeline easement across CP&L's property.

9. Rowan Generating will file pursuant to G.S. 62-101 for a certificate of environmental capability and public convenience and necessity for its transmission line.

ELECTRIC MERCHANT PLANT - CERTIFICATE

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 the application and the testimony and exhibits of the witnesses for Rowan Generating.

Rowan Generating witness Williams testified that Entergy owns, manages or invests in power plants generating more than 30,000 MW of electricity domestically and internationally and delivers electricity to over 2.5 million retail customers; it is also a leading provider of wholesale energy marketing and trading services. Entergy ranks among the largest U.S. utility companies, with operating revenues of $10 billion in 2000 and over $25 billion in assets. Williams testified that Rowan Generating is a limited liability company organized under the laws of the State of Delaware with its principal place of business in The Woodlands, Texas. Rowan Generating is a single-purpose company formed to continue and complete the development and operation of the facility proposed herein. Rowan is an indirect subsidiary of Entergy and a direct subsidiary of EPGC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding is found in the application and the testimony and exhibits of Rowan Generating witnesses Williams, Cornell, and Marigny and Public Staff witness Salib.

G.S. 62-110.1 and Commission Rule R8-63 require that no person may begin construction of any facility for the generation of electricity to be directly or indirectly used for furnishing public utility service without first obtaining from the Commission a certificate that the public convenience and necessity requires or will require such construction. The Public Staff notified the Commission on May 23, 2001, that it considered the application filed herein to be complete. An examination of the application and testimony and exhibits of the Rowan witnesses confirms that Rowan has complied with the filing requirements of the statute and rule.

Based on the application and the testimony and exhibits of the witnesses, the Commission concludes that Rowan Generating has complied with the procedural requirements for applying for a certificate for a merchant plant in North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Public Staff witness Salib recommended that the certificate be granted upon the condition that the Applicant abstain from attempting to exercise any power of eminent domain. Rowan Generating's attorney stated that it agrees to this recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

This finding of fact incorporates provisions of Commission Rule R8-63(e) and (f), adopted in Docket No. E-100, Sub 85. These provisions require, among other things, that the certificate shall be subject to revocation under specified circumstances, that the certificate must be renewed if construction is not begun in two years, that Rowan Generating must notify the Commission of plans to sell or transfer or assign the certificate and facility, and that Rowan Generating shall submit to the

Commission annual progress reports and any revisions in cost estimates until construction is completed. All the provisions of Rule R8-63(e) and (f) shall apply to this certificate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 AND 7

The evidence for these findings is found in the application and the testimony and exhibits of Rowan Generating witnesses Williams, Cornell, and Marigny, Public Staff witness Salib, and public witness Harrell.

The Rowan Generating witnesses testified to the plan to construct a combustion turbine generating plant in Rowan County. The facility will consist of six natural gas-fired, simple-cycle General Electric combustion turbine generator packages with a gross electric generation capacity of approximately 900 MW. The expected service life of the facility is approximately forty years. Construction is anticipated to begin in the first quarter of 2002, and commercial operation is scheduled to begin in the second quarter of 2003. Witness Cornell testified that the facility will occupy approximately 30 acres of a 118-acre tract of land approximately six miles west-northwest of the town of Salisbury. The site is located at the intersection of NC Highway 801 and Old Highway 70 (Barber Road). The facility will be accessed on the west side of the property via NC Highway 801. Each combustion turbine generator will be manufactured and supplied by General Electric with a design net electrical output of approximately 150 MW. The primary fuel for the combustion turbines will be natural gas. The combustion turbines will have the capability of fuel changeover during operation to low sulfur distillate oil. Cornell testified that a fuel oil storage tank system with a maximum usable capacity of approximately 4,200,000 gallons will be utilized for distillate oil storage. The storage tanks will be filled by truck deliveries from local suppliers. A connection for natural gas supply will be made by Piedmont Natural Gas Company to the Transcontinental Gas Pipe Line Company interstate natural gas pipeline, which is located approximately 17,000 feet from the site. Process water will be supplied to meet the needs of the facility's power generation process by a connection to the City of Salisbury's water system. The primary uses of process water will be for inlet cooling of the combustion turbine inlet air, for cleaning the internals of the combustion turbine, for fire protection, and for injection into the combustion turbine units for the control of nitrogen oxide emissions when the turbines are using distillate fuel oil.

Cornell testified that the facility will be connected to Duke Electric Transmission's existing transmission system via the Woodleaf Switching Station just south of CP&L's Rowan County generating plant. A short, single circuit 500 kV transmission line will be constructed for the interconnection. The transmission line right-of-way will be 200 feet wide and extend approximately 300 feet from the facility's property boundary to the switching station. This right-of-way will cross the property of only one adjacent property owner, CP&L.

Williams and Cornell testified that the facility will operate as a fully dispatchable peaking facility, starting up, shutting down, and changing load as necessary to meet the peak electrical loads for this region. This facility should complement the existing generation assets in the region and is not expected to replace any of those facilities. Williams testified that in determining whether or not there is a need for a proposed facility, Rowan Generating staff reviewed publicly available information such as reliability studies, North American Reliability Council (NERC) and Southeast Reliability Council (SERC) data, and other regional data because of the importance of regional planning in determining the need for capacity. Williams testified that the Rowan facility is needed to meet anticipated demand in the SERC region, that the facility will promote system economy and reliability, and the facility will serve the public convenience and necessity. Williams testified that if Entergy did not see a need for this project in North Carolina, it would not build the plant at this location or on this schedule, since this is an "at risk" capital investment with no security from traditional rate base treatment. Williams further stated that the Rowan Generating facility will enhance North Carolina's ability to meet current and future electric needs. Having the plant in North Carolina also helps provide security of supply to the state. In addition, a new facility like the proposed Rowan project adds millions of dollars to the local economy, expands the local tax base, and creates many construction jobs, as well as permanent jobs once the facility becomes operational.

Williams testified that the facility will promote the interests of system economy in a number of ways. First, North Carolina consumers will only pay for additional capacity if and when they purchase it. Williams testified that Rowan Generating will be taking all of the risk if the forecasted demand growth does not occur. Second, the facility is planned to run on natural gas and will utilize one of the most advanced and economically efficient generating processes available on the market today. Third, the facility also will enhance fuel diversity, which will protect North Carolinians from adverse economic impacts due to price increases in a single commodity or changes in regulation of a single technology. According to Williams' testimony, disproportionate reliance on a single fuel source or a single technology can place upward pressure on prices and costs, thus increasing vulnerability to service disruptions and price spikes. He further testified that a fourth benefit is that when peaking capacity is needed to serve North Carolinians and others in the region, they will have access to an extremely clean, efficient and economical energy source. Fifth, he testified that availability of additional peaking capacity will allow North Carolina to align the mix of capacity purchases more closely with demand. The current capacity mix in North Carolina is heavily weighted towards base load generation. While SERC has an overall need for new capacity, Williams testified that it does have sufficient coal, hydro and nuclear base load resources. Williams concluded that the Rowan facility will help balance this capacity mix portfolio. Williams further testified that the projected growth in demand for electric generation in the county, state, and region establish the need for additional supply requirements and that Entergy is prepared to make the necessary investment to provide safe and reliable generation to meet this demand and, at the same time, provide tax revenues, jobs, and other economic benefits for Rowan County and North Carolina.

The witness referred to the Department of Energy's Energy Information Administration 2000 Form 411 report and stated that in the SERC region, the average growth in summer peak demand is expected to be approximately 2.23% annually. Much of this growth will come from residential and commercial users who use more capacity during daylight hours. Public Staff witness Salib agreed that this type of demand can best be met with more flexible generating capacity that can be most effectively provided by gas combustion turbines similar to those proposed in this project. The Rowan Generating witness also referred to the Commission's Annual Report dated July, 2000, noting that CP&L includes over 2,000 MW and Duke includes over 5,000 MW of undesignated generating capacity additions for the 2000-2009 planning period.

Harrell testified as a public witness on behalf of the Salisbury-Rowan Economic Development Commission and the Rowan County Board of Commissioners to recommend that the Commission grant Rowan Generating the certificate of public convenience and necessity. Harrell testified that it is the opinion of the Rowan County Board of Commissioners that this project will be of great economic benefit to the county and its citizens by increasing the tax base and employment opportunities while having very little impact on the county's infrastructure and system of services. During its construction cycle, peak employment will account for more than 200 jobs with an annual labor investment of approximately $1.2 million. It is anticipated that many of these jobs will come to local workers. Harrell anticipated that when the plant begins commercial operations it will add 10 to 15 permanent jobs with an estimated annual payroll of more than $500,000. The plant will run on natural gas, a clean burning fuel that is both energy efficient and environmentally friendly. In addition, the project will bring a major capital investment of over $400 million to Rowan County. Harrell concluded that this project is a welcome addition to the Rowan business community and requested Commission approval. Harrell offered resolutions unanimously passed by the Rowan County Board of Commissioners and the Salisbury-Rowan Economic Development Commission in support of the project.

Rowan Generating witness Marigny testified regarding the status of the environmental permitting process and the minimal nature of the anticipated environmental impact from the construction and operation of the facility and discussed the location and site of the proposed facility. Marigny stated that Entergy is committed to a high standard of environmental performance and that having a record of excellent environmental performance is vital to being welcomed into any community where Entergy operates, including communities here in North Carolina. She testified that Entergy is one of the largest electric power companies in the United States and one of the cleanest. For example, the average air emissions rate for Entergy is one and one-half to three times lower than the national average for emissions of nitrogen oxides and sulfur dioxide. Adding carbon dioxide, Entergy has the sixth lowest composite emissions rate among the fifty largest electric utilities in the country. She claimed that the combustion turbines Entergy intends to install are considered "best in class" with lower air emissions compared to other generating technology. According to Marigny, Entergy anticipates that potential impacts on water quality, sound, air quality, and natural resources from the construction and operation of the facility will be minimal. The proposed facility is located in an attainment area and will operate as a simple cycle peaking facility burning natural gas primarily and low-sulfur diesel fuel as an alternative fuel source. Natural gas-fired combustion turbine generating facilities exhibit significant environmental advantages over traditional coal or oil-burning steam boiler power plants, both with respect to environmental emissions as well as demand on natural resources. Traditional power plants usually require hundreds of acres of land for equipment and support facilities, including waste treatment and pollution control facilities, while simple-cycle turbine peaking facilities such as the Rowan Generating facility require only 20 to 50 acres. Marigny testified that Entergy has filed the required environmental applications and reports for permitting and that the facility will comply with all applicable state and federal environmental regulations and statutes in the future.

The Commission has carefully considered the entire record in this proceeding on both the need for the facility, the environmental impact of the facility and the economic benefit of the facility to the State. While the Commission is mindful that issues regarding the appropriate amount of merchant plant generation in the State remain to be decided, it concludes that it should grant the requested certificate of public convenience and necessity.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 AND 9

The evidence for these findings is found in the testimony and rebuttal testimony of Rowan Generating witness Williams, Public Staff witness Salib, the joint letter filed by CP&L and EPGC on August 15, 2001, and the notice of intent filed by Rowan Generating on September 12, 2001.

Public Staff witness Salib expressed concern because a transmission line right-of-way had not been obtained at the time the Public Staff's testimony was filed and because the pending dispute with CP&L was not referenced in the application. Williams' rebuttal testimony addressed Entergy's efforts to obtain the easement across CP&L's property to interconnect to the Woodleaf switchyard. CP&L and EPGC filed a joint letter on August 15 stating that as of August 7, 2001, CP&L and EPGC entered into a memorandum of understanding. In the memo, CP&L agreed to grant to EPGC, for valuable consideration, a transmission easement for transmission interconnection access from the proposed Rowan facility to Duke Electric Transmission's Woodleaf switchyard and to grant a permanent gas pipeline easement across a separate portion of CP&L's property. The easements will allow EPGC to construct, install, operate, utilize, inspect, rebuild, repair, replace, remove and maintain overhead and/or underground facilities consisting of electric, gas or other fuel products. The Commission understands that all issues regarding the right of way across CP&L's adjoining site have been resolved.

An issue was raised as to whether Rowan Generating must get an additional approval under G.S. 62-101 for its transmission line. In its application, Rowan Generating stated that it intended to seek a certificate of environmental compatibility and public convenience and necessity under G.S. 62-101 for its new transmission line. However, in its proposed order, Rowan Generating stated that no further proceedings were required under G.S. 62-101. The Public Staff and Attorney General disagreed with this statement. In post-hearing comments, the Public Staff stated that a certificate of environmental compatibility and public convenience and necessity under G.S. 62-101 is required, but the Public Staff agreed that waiver of public notice and hearing may be reasonable and, further, that information already provided in this docket may be incorporated into the G.S. 62-101 filing. The Attorney General stated that no exception to the G.S. 62-101 certificate requirement applies and that the Commission Rule on certifying merchant plants does not obviate the need to comply with G.S. 62-101. In response to these comments, Rowan Generating filed a notice of intent on September 12, 2001, agreeing to file for a certificate for the transmission line pursuant to G.S. 62-101. The notice stated that neither the Public Staff, the Attorney General, nor CP&L objected to waiver of public notice and hearing and, further, that the Public Staff agrees to waive the prefiling requirement of Commission Rule R8-62(k) in connection with the transmission line certificate application. Rowan Generating filed pursuant to G. S. 62-101 on October 9, 2001, in Docket No. EMP-3, Sub 1. The Commission concludes that the parties are now in agreement on this issue and that Rowan Generating has filed for a certificate of environmental capability and public convenience and necessity pursuant to G.S. 62-101.

IT IS, THEREFORE, ORDERED as follows:

1. That a Certificate of Public Convenience and Necessity should be issued to Rowan Generating for the construction of a natural gas-fired, combustion turbine merchant plant generating facility of approximately 900 MW in Rowan County, and the same is attached hereto as Appendix A;

2. That the certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and the certificate is conditioned upon Rowan Generating's abstaining from attempting to exercise any power of eminent domain in connection with this facility; and

3. That the certificate is subject to the conditions set forth in Rule R8-63(e) and (f) and in this order.

ISSUED BY THE ORDER OF THE COMMISSION
This the 12th day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg101201.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-3, SUB 0

ROWAN GENERATING COMPANY, LLC
Parkwood Two Building, Suite 150, 10055 Grogan's Mill Road,
The Woodlands, Texas 77380

is hereby granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of a natural gas-fired, combustion turbine
merchant plant generating facility of approximately 900 MW

located

approximately six miles west-northwest of the town of Salisbury at the
intersection of NC Highway 801 and Old Highway 70
in Rowan County, North Carolina,

subject to Commission Rule R8-63(e) and (f) and all orders, rules, and regulations that have been and may hereafter be lawfully made by the North Carolina Utilities Commission. In addition, this Certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and Rowan Generating Company, LLC, shall abstain from attempting to exercise any power of eminent domain pursuant to this Certificate.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

DOCKET NO. EMP-4, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of GenPower Earleys, LLC For a Certificate of Public Convenience And Necessity to Construct a Natural Gas-Fired Electric Power Generating Facility in Hertford County, North Carolina	))))))	ORDER GRANTING CERTIFICATE

HEARD ON: Tuesday, August 21, 2001, at 10:00 a.m., and Wednesday, September 5, 2001, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, Chair Jo Ann Sanford, and Commissioners J. Richard Conder, Robert V. Owens, Jr. and James Y. Kerr, II

APPEARANCES:

For GenPower, LLC:

W. Edward Poe, Jr., Parker, Poe, Adams & Bernstein L.L.P., Three First Union Center, 401 S. Tryon Street, Suite 3000, Charlotte, North Carolina 28202

For the Using and Consuming Public:

Gisele L. Rankin, Staff Attorney, Public Staff – N.C. 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 27602-0629

BY THE COMMISSION: On April 2, 2001, GenPower Earleys, LLC (hereinafter referred to as GenPower), a wholly owned subsidiary of GenPower, LLC, filed preliminary plans for its Earleys electric generating facility, as required by North Carolina Utilities Commission Rule R8-61. At the same time, it filed a request for waiver of the 120-day prefiling requirement contained in Rule R8-61 so that it could proceed with filing its application. On April 18, 2001, the Commission entered an order waiving the prefiling requirement.

On May 11, 2001, GenPower filed an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1, in which it requested the Commission to authorize construction of a combined-cycle merchant plant electric generating facility with a nominal rating of 528 megawatts (MW) and a peak rating of 640 MW to be located in Hertford County, North Carolina. On the same date, GenPower filed the testimony and exhibits of Joseph E. Sharbaugh, Manager of Project Development, in support of the application. GenPower submitted supplemental information in support of its application on May 22, 2001, and June 8, 2001.

On June 8, 2001, the Public Staff filed a notice of completeness indicating that GenPower's application complied with the requirements of Commission Rule R8-63 and recommending that GenPower's application be set for hearing pursuant to G.S. 62-82. On June 18, 2001, the Commission entered an order scheduling a public hearing on GenPower's application, requiring GenPower to provide appropriate public notice, establishing deadlines for the filing of interventions and testimony, and requiring the parties to comply with certain discovery deadlines. On June 26, 2001, the Commission entered an order rescheduling the hearing at which the Commission would receive the testimony of the parties and limiting the previously scheduled hearing to testimony from public witnesses.

On July 31, 2001, GenPower filed an affidavit of publication indicating that public notice had been provided as required. On May 25, 2001, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene, which was allowed by Commission order dated June 6, 2001. On July 19, 2001, Roy Cooper, Attorney General, filed a notice of intervention pursuant to G.S. 62-20. The Public Staff participated pursuant to G.S. 62-15(d) and Commission Rule R1-19(e).

On August 17, 2001, the Public Staff filed the joint testimony of Sami M. Salib, Thomas W. Farmer, Jr., and Jan A. Larsen. No other party submitted prefiled testimony in this proceeding. No party filed rebuttal testimony.

On August 21, 2001, the Commission conducted a hearing for the purpose of receiving testimony from public witnesses. William Early, Economic Development Director and Planning and Zoning Administrator for Hertford County, testified as a public witness and requested that the Commission grant the certificate. On September 5, 2001, the Commission held a hearing to receive the pre-filed testimony of the parties. CUCA did not appear at the hearing; the other parties stipulated the prefiled testimony of the GenPower and Public Staff witnesses and asked no questions. Several Commissioners asked questions of GenPower witness Sharbaugh. Following the hearing, GenPower filed a proposed order, with which the Public Staff agrees. The Attorney General filed a letter stating that he "supports the development of merchant plants in North Carolina and does not take issue with the proposed order."

Based upon the testimony presented at the hearing and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. GenPower is a limited liability company organized under the laws of Delaware with its principal place of business in Hertford County, North Carolina. GenPower is wholly owned and controlled by GenPower, LLC.

2. GenPower, LLC, which is headquartered in Needham, Massachusetts, specializes in the development of natural gas-fired electric generating facilities in the United States and, to date, has developed 1,736 MW of gas-fired combined-cycle electric generating facilities.

3. In compliance with G.S. 62-110.1 and Commission Rule R8-63, GenPower properly filed with the Commission an application for a certificate of public convenience and necessity in which it requested the Commission to authorize the construction of an approximately 528 MW (nominal) and 640 MW (peak) natural gas-fired combined-cycle merchant plant electric generating facility to be located in Hertford County, North Carolina.

4. The certificate should be conditioned upon GenPower, or its successor, abstaining from attempting to exercise any power of eminent domain as it relates to this facility.

5. The Commission set forth a number of conditions that apply to merchant plant certificates in Rule R8-63(e) and (f), and these conditions are relied upon by the Commission in its determination that the public convenience and necessity are served by the construction of the facility proposed herein.

6. The granting of the certificate in this docket also should be conditioned upon additional requirements as follow:

(1) GenPower shall file, under seal if necessary, a summary of GenPower's proposed construction financing within thirty (30) days of such financing's being finalized and shall file, under seal if necessary, a summary of any proposed commitments related to permanent equity financing at the time that any such commitments are considered reasonably final, all within 9 months from the date of this order;

(2) GenPower shall file an application for approval of any proposed change in ownership and/or control of the project and for transfer of the certificate, such application to be filed prior to any unconditional commitments being made concerning ownership interests in the project and sixty (60) days prior to the date Commission approval is desired, but in no event more than 9 months from the date of this order; and

(3) GenPower, or its successor, shall contract with North Carolina Natural Gas Corporation (NCNG) for natural gas interconnection facilities for the project.

7. The granting of the certificate in this docket is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring, or assigning the certificate and/or generating facility.

8. GenPower has made a sufficient showing of need for this proposed facility based on the anticipated growth in electrical demand expected in the Virginia-Carolina (VACAR) market region, which is a sub-region of the Southeast Electric Reliability Council (SERC) power market area and includes the entire State of North Carolina.

9. It is reasonable and appropriate to grant the requested certificate.

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 the application and the testimony and exhibits of the witness for GenPower.

GenPower witness Sharbaugh testified that GenPower, LLC has developed power plants that are generating or will generate 1,736 MW of electricity in the United States. Three gas-fired, combined-cycle facilities developed by GenPower, LLC are in Westbrook, Maine; Dell, Arkansas; and McAdams, Mississippi.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding is found in the application and the testimony and exhibits of GenPower witness Sharbaugh and Public Staff witnesses Salib, Farmer and Larsen.

G.S. 62-110.1, and Commission Rule R8-63 provide that no person may begin construction of any facility for the generation of electricity to be directly or indirectly used for furnishing public utility service without first obtaining from the Commission a certificate that the public convenience and necessity requires or will require such construction. The Public Staff notified the Commission on June 8, 2001, that it considered the application of GenPower to be complete. An examination of the application and the testimony and exhibits of the witnesses confirms that GenPower has complied with the filing requirements of the statute and the rule for applying for a certificate for a merchant plant electric generating facility in North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is found in the testimony Public Staff witnesses Salib, Farmer and Larsen and GenPower witness Sharbaugh.

Public Staff witnesses Salib, Farmer and Larsen recommended that the certificate be granted upon the condition that GenPower abstain from attempting to exercise any power of eminent domain. GenPower witness Sharbaugh testified that GenPower did not disagree with any of the Public Staff's proposed conditions. The Commission concludes that this condition should be adopted and, for reasons discussed hereinafter, should be applied to any successor on GenPower.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

This finding of fact incorporates provisions of Commission Rule R8-63(e) and (f), adopted in Docket No. E-100, Sub 85. These provisions require, among other things, that the certificate shall be subject to revocation under specified circumstances, that the certificate must be renewed if construction is not begun in two years, that Rowan Generating must notify the Commission of plans to sell or transfer or assign the certificate and facility, and that Rowan Generating shall submit to the Commission annual progress reports and any revisions in cost estimates until construction is completed. All the provisions of Rule R8-63(e) and (f) shall apply to this certificate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 6 AND 7

The evidence for this finding of fact is found in the testimony Public Staff witnesses Salib, Farmer and Larsen and GenPower witness Sharbaugh.

Public Staff witnesses Salib, Farmer and Larsen recommended that the certificate be granted based upon a number of conditions. In addition to recommending that GenPower refrain from exercising the power of eminent domain, these witnesses recommended that certain filing requirements related to proposed construction financing and permanent equity financing be imposed. They testified that GenPower, LLC was a small company dependent upon external sources of financing. GenPower, LLC sold each of its three developed projects prior to the start of construction. Because external funding sources are expected to require substantial equity participation in and control of the project, GenPower may become, at most, a minority owner of the facility proposed herein. Therefore, the Public Staff witnesses urged that GenPower be required to file (under seal, if necessary) a summary of its proposed construction financing within thirty (30) days of such financing being finalized and a summary of any proposed commitments related to permanent equity financing at the time any such commitments are considered reasonably final. In addition, the Public Staff witnesses recommended that the certificate be conditioned upon GenPower's filing an application for approval of any proposed change in the ownership and/or control of the project and to transfer the certificate, prior to any unconditional commitments being made concerning ownership interests in the project and sixty (60) days prior to the date Commission approval is desired. However, the Public Staff witnesses recommended that this condition apply only until construction is completed and commercial operation is achieved. Subsequently, GenPower or any successor certificate holder should comply with the notice provisions of Commission Rule R8-63(e)(4) rather than file an application for approval.

Finally, the Public Staff witnesses testified that the granting of the certificate should be conditioned upon GenPower, or its successor, contracting with NCNG for natural gas interconnection facilities for the project. GenPower's facility is approximately one mile from a 12-inch high-pressure transmission main owned by NCNG, compared to being 4.5 miles from Transcontinental Gas Pipe Line Corporation's (Transco) transmission main. Witness Sharbaugh testified that GenPower was currently in negotiations with NCNG to determine a proper rate to be charged to the facility. If an agreement cannot be reached within a reasonable amount of time, GenPower and NCNG should file their last best offers (under seal, if necessary) and the Commission will then determine the disputed terms of the contract.

The Commission concludes that the certificate should be conditioned upon the three additional conditions recommended by the Public Staff and agreed to by GenPower. In addition, the Commission believes it is appropriate for GenPower to continue to negotiate with NCNG as to the rates, terms and conditions for the delivery of natural gas for the facility through interconnection facilities owned and controlled by NCNG. If an agreement cannot be reached within a reasonable amount of time after the issuance of this order, the matter shall be submitted to the Commission for a determination of such rates and charges.

In addition to the conditions recommended by the Public Staff, the Commission will impose an additional condition related to construction financing and permanent equity financing. In response to questions asked by Commissioners, GenPower witness Sharbaugh testified that GenPower, LLC does not own or operate any electric generating facilities, despite the statement in his prefiled testimony that "GenPower, LLC is an employee-owned limited liability company that develops, owns and operates electrical generating facilities in the United States." Witness Sharbaugh also testified that GenPower, LLC intends "to attempt to negotiate a position" in its projects but has yet to do so, that GenPower is not capable of constructing or operating the proposed Earleys project alone, that GenPower will solicit equity participation in this project after receiving the air permit, and that GenPower will "write the project off" if no equity participant is found. Although no party has raised the issue, the Commission would be remiss if it did not consider the impact of this testimony on whether a certificate should be issued herein.

Based upon this testimony, it is clear from the outset that the applicant herein is not capable of constructing the project it proposes and that, by the time construction begins, the applicant before us now may be a minority owner, or no owner at all, in the project. G.S. 62-111(d) provides that no person shall obtain a "franchise" for the purpose of transferring it to another. A "franchise" is generally defined by statute as a grant of authority to engage in business as a public utility. G.S. 62-3(11). GenPower will not be a public utility, so the prohibition in G.S. 62-111(d) does not apply. However, the statute states a policy as to public utilities, and the Commission must decide whether a similar policy should be applied to merchant plants. GenPower is applying for a certificate under G.S. 62-110.1 to construct an electric generating facility that will be used, directly or indirectly, for furnishing public utility service. The standard to be applied is whether the "public convenience and necessity requires, or will require, such construction." Public convenience and necessity is an elastic concept which must be determined on the basis of all relevant facts and circumstances. Thus, it is within the Commission's discretion under the public convenience and necessity standard to consider and decide what effect should be given to the fact that the company applying for the certificate will need equity participation from parties now unknown in order to actually construct the facility it proposes.

The Commission has an interest in staying informed as to the state of electric generation in North Carolina and in ensuring the adequacy and reliability of public utility service. Although the Commission has taken steps to streamline procedures for merchant plant applicants, it is still important that the persons who will construct electric generating facilities subject to G.S. 62-110.1 come before the Commission. It is clear from the testimony that an electric generating facility such as that proposed herein requires an assembly of valuable and limited resources, including natural gas availability, substantial water supply, and access to the electric transmission grid. The Commission has initiated a proceeding to determine how scarce such sites are, but it is clear that the number of sites with such resources is finite. Thus, even while that proceeding is pending, the Commission has an interest in seeing that the people who acquire sites with such resources and who seek a certificate to construct electric generating facilities on the sites can in fact carry through with their plans within a reasonable time frame. Rule R8-63(e)(3) already provides that a certificate must be renewed if construction is not begun within two years from issuance. In light of the evidence in this case, the Commission concludes that it is appropriate to put an additional time limit on GenPower's efforts to obtain financing and equity participation. As a condition of this certificate, GenPower must arrange its construction financing and its permanent equity financing and file summaries thereof and, in addition, file for approval of any proposed change of ownership and/or control and for transfer of the certificate, as hereinabove required, all within 9 months from the date of this order. If it has not done so within 9 months, the certificate will lapse at that time. Witness Sharbaugh testified that GenPower would seek financing after obtaining its air permit and he estimated that the final air permit would be issued in February 2002. The time allowed herein should therefore be sufficient for GenPower to proceed as planned, but it will require that progress be made and that a schedule be maintained.

Consideration of this issue raises anew a related issue that was considered but deferred in the Commission's recent proceeding to adopt Commission Rule R8-63, Docket No. E-100, Sub 85. The issue is whether transfers of merchant plant certificates should be subject to Commission approval. In that rulemaking proceeding, the Public Staff commented that the Commission needs some continuing authority as to how merchant plants are being used, even after the certificate is issued and construction completed. The Public Staff proposed that such continuing authority could be achieved by issuing the certificate with a condition that any subsequent transfer be subject to Commission approval. The Commission's May 21, 2001 Order Adopting Rule wrote into Rule R8-63(e)(4) the requirement that a certificate holder must give notice of any plans to sell, transfer or assign the certificate and facility, but the Commission left the issue of whether a certificate holder must get Commission approval of a sale, transfer or assignment for consideration in future, individual certificate cases.

In the present docket, the Public Staff witnesses recommended that GenPower's financing and equity participation should be subject to Commission approval, but they recommended that this requirement should apply only until construction is completed and commercial operation is achieved. The Public Staff witnesses recommended that, after that time, GenPower or any successor certificate holder should comply with the notice provisions of Commission Rule R8-63(e)(4), rather than file for approval. The Commission believes that more should be required. The situation presented by this case re-emphasizes that merchant plants provide public utility service, directly or indirectly, and that the Commission should maintain some continuing monitoring and oversight as to them. As noted earlier, the Commission is responsible for staying informed as to the state of electric generation in North Carolina and ensuring the adequacy and reliability of public utility service. Further, it is important for planning purposes and for preventing market abuses that the Commission have more than just notice when a merchant plant is sold, transferred or assigned. The Commission must be able to act on this notice if it is to perform its duties under law. Therefore, the Commission will require, as a continuing condition of the merchant plant certificate, that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 AND 9

The evidence for these findings is found in the application, the testimony and exhibits of GenPower witness Sharbaugh, and the testimony of Public Staff witnesses Salib, Farmer and Larsen and public witness Early.

GenPower witness Sharbaugh explained the plan to construct a combustion turbine plant in Hertford County. The facility will consist of two General Electric natural gas-fired combustion turbine generators, two heat recovery steam generators and one reheat condensing steam turbine with a total nominal rating of 528 MW and a total peak rating of 640 MW. Additional equipment includes an auxiliary boiler, an emergency generator, a diesel-fired fire pump and a cooling tower system.

Construction is anticipated to begin on April 1, 2002, and commercial operation is scheduled to begin on June 1, 2004. Witness Sharbaugh testified that the facility will be sited on a 178-acre tract of land approximately one mile south of the intersection of NC Highway 11 and State Road 1109 in Hertford County. The facility will be accessed via a private drive off State Road 1109.

A connection for natural gas supply to the facility will be made by NCNG to Transco's interstate natural gas pipeline, which is located 4.5 miles from the site. Process water will be supplied to meet the needs of the facility's power generation process by connection to a proposed regional wastewater reuse facility. This facility will collect approximately four million gallons of wastewater per day from the municipalities of Ahoskie, Murfreesboro, Aulander and Winton and from Perdue Farms in Lewiston. After treatment, this wastewater will be piped to GenPower's facility where approximately 90% of it will be evaporated as cooling water, with the remaining 10% returned for treatment and disposal. The facility will be connected to the existing Earleys 230/115 kV substation owned by Virginia Electric and Power Company (Dominion Virginia Power), which is located 4,750 feet north of the facility at the corner of NC Highway 11 and State Road 1109, via at least one 230 kV transmission line. Dominion Virginia Power will construct and own the 230 kV line from its Earleys substation to the plant switchyard located on the site. The right-of-way for this transmission line will run parallel to Dominion Virginia Power's existing 230 kV transmission line.

Witness Sharbaugh explained that the facility will be operated to provide base load merchant plant power. It is anticipated that it will be called upon to operate a maximum of 8,000 hours per year. The combustion gas turbine generators will be shut down as necessary for scheduled maintenance or as dictated by economic or electrical demand. The facility should complement the existing generation assets in the region and is not expected to replace any of those facilities.

Witness Sharbaugh testified that in determining whether or not there is a need for the proposed facility, GenPower contracted with Pace Global Energy Services (Pace) to research market conditions and trends regarding future electrical demand in the VACAR sub-region of the SERC power market area. This market forecast had two components: econometric models used to forecast annual peak demand and energy levels, and translation of historical hourly demand levels and forecasted peak demands to create predicted hourly load for each forecast year. The Pace study projected that demand for electrical power will increase by an average of over two percent per year during the next 20 years in the VACAR sub-region. The study projected a need for an additional 14,000 MW of generating capacity in the VACAR sub-region by the end of 2010 and over 50,000 MW of new generating capacity by the end of 2025. The electrical energy produced by the GenPower Earleys project would represent approximately four percent of the additional electrical generation capacity needed in the VACAR sub-region through 2010. If additional electrical generation capacity does not keep pace with increasing demand in the VACAR sub-region, a deterioration of electrical service reliability is likely to occur. The Pace study also stated that GenPower had selected the appropriate choice of generating technology, i.e. a highly efficient power plant using current combined-cycle technology, considering the segment of the power market that will be served by the facility.

Witness Sharbaugh testified that the Earleys facility is needed to meet anticipated demand in the VACAR sub-region and that the facility will promote system economy and reliability, and the facility will serve the public convenience and necessity. Mr. Sharbaugh stated that the Earleys facility will enhance North Carolina's ability to meet current and future electric needs. In addition, this facility will expand the local tax base and create new jobs, both construction and permanent. Mr. Sharbaugh asserted that the projected growth in demand for electric generation in the State and region established the need for additional supply requirements, and that GenPower is prepared to make and arrange for the necessary investment to provide safe and reliable generation to meet this demand and, at the same time, provide tax revenues, jobs and other economic benefits for Hertford County.

Witness William Early, Economic Development Director and Planning and Zoning Administrator for Hertford County, testified as a public witness. He recommended that the Commission grant GenPower a certificate of public convenience and necessity. He testified that this project will be of major economic benefit to the county and its citizens by increasing the tax base and employment opportunities as well as helping to solve wastewater disposal problems for municipalities and industries in the county through the regional wastewater reuse facility. He further testified that the project will bring a major capital investment of approximately $350 million to Hertford County.

Witness Sharbaugh testified regarding the status of the environmental permitting process and the minimal nature of the anticipated environmental impact from the construction and operation of the facility and discussed the location and site of the proposed facility. Mr. Sharbaugh stated that GenPower is committed to a high standard of environmental performance. According to Mr. Sharbaugh, GenPower anticipates that potential impacts on water quality, sound, air quality and natural resources from the construction and operation of the facility will be minimal. Mr. Sharbaugh stated that GenPower has filed the required environmental applications and reports for permitting and the facility will comply with all applicable state and federal environmental regulations and statutes.

The Commission has carefully considered the entire record in this proceeding and specifically the evidence presented by GenPower, the Public Staff and witness Early and concludes that the requested certificate should be granted subject to the conditions set forth herein.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity should be issued to GenPower Earleys, LLC for the construction of a natural gas-fired combined-cycle merchant electric generating facility with a total nominal rating of 528 MW and a total peak rating of 640 MW in Hertford County, and the same is attached hereto as Appendix A;

2. That the certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and the certificate is conditioned upon GenPower's, or its successor, abstaining from attempting to exercise any power of eminent domain in connection with the facility;

3. That the certificate is subject to the conditions in Rule R8-63(e) and (f);

4. That the certificate is also conditioned upon the following:

a. GenPower shall file, under seal if necessary, a summary of its proposed construction financing within 30 days of such financing being finalized and shall file, under seal if necessary, a summary of any proposed commitments related to permanent equity financing at the time that any such commitments are considered reasonably final, all within 9 months from the date of this order;

b. GenPower shall file an application for approval of any proposed change in ownership and/or control of the project and for transfer of the certificate, such application to be filed prior to any unconditional commitments being made concerning ownership interests in the project and 60 days prior to the date Commission approval is desired, but in no event more than 9 months from the date of this order; and

c. GenPower, or its successor, shall contract with NCNG for natural gas interconnection facilities for the project;

5. That the certificate is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facility; and

6. That GenPower shall continue to negotiate with NCNG as to the rates, terms and conditions with respect to the delivery of natural gas through interconnection facilities owned and controlled by NCNG and if agreement cannot be reached within a reasonable amount of time after the issuance of this order, the matter shall be submitted to the Commission for a determination of such rates and charges.

ISSUED BY THE ORDER OF THE COMMISSION
This the 20th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg110501.03

ELECTRIC MERCHANT PLANT - CERTIFICATE

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-4, SUB 0

GENPOWER EARLEYS, LLC
1040 Great Plain Avenue
Needham, Massachusetts 02492

is hereby granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO N.C.G.S. 62-110.1

for construction of a natural-gas fired, combustion turbine merchant plant
generating facility with a nominal rating of 528 MW and a peak rating of 640 MW
located
approximately one mile south of the intersection of NC Highway 11
and State Road 1109 in Hertford County, North Carolina,

subject to Commission Rule R8-63(e) and (f) and all orders, rules, and regulations that have been and may hereinafter be lawfully made by the North Carolina Utilities Commission. In addition, this Certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and GenPower Earleys, LLC, or its successor, shall abstain from attempting to exercise any power of eminent domain pursuant to this Certificate. In addition, this Certificate is conditioned upon (1) GenPower Earleys, LLC filing a summary of proposed construction financing within 30 days of such financing being finalized and filing a summary of any proposed commitments related to permanent equity financing at the time same are considered reasonably final, all within 9 months from the date of this order; (2) GenPower Earleys, LLC filing an application for approval of any proposed changes in ownership and/or control of the project and for transfer of the certificate prior to any unconditional commitments being made concerning ownership interests in the project and 60 days prior to the date Commission approval is desired, but in no event more than 9 months from the date of this order; and (3) GenPower Earleys, LLC, or its successor, contracting with North Carolina Natural Gas for gas interconnection facilities for the project. This Certificate is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facility.

ISSUED BY ORDER OF THE COMMISSION
This the 20th day of November, 2001

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

ELECTRIC MERCHANT PLANT - CERTIFICATE

DOCKET NO. EMP-5, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Progress Energy Ventures, Inc., for a	)	ORDER GRANTING
Certificate of Public Convenience and Necessity tog	)	CERTIFICATE FOR
Construct 640 MW of Generation Facilities in Richmond	)	GENERATING FACILITIES
County and 640 MW of Generation in Rowan County	)	IN ROWAN COUNTY

HEARD: Thursday, August 16, 2001, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Judy Hunt, Richard Conder, Sam J. Ervin, IV, Robert V. Owens, Jr. and James Y. Kerr, II

APPEARANCES:

For Progress Energy Ventures, Inc.:

Len S. Anthony, Manager, Regulatory Affairs, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the North Carolina Attorney General:

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

For the Public Staff:

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

BY THE COMMISSION: On November 30, 2000, in Docket E-2, Sub 777, Carolina Power & Light Company (CP&L) filed preliminary plans pursuant to Commission Rule R8-61 to construct an additional 635 megawatts of electric generating facilities at its Richmond County site and 626 megawatts of electric generating facilities at its Rowan County site, to achieve the full expansion capability of both sites.

On February 21, 2001, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Order dated February 27, 2001. On March 9, 2001, Carolina Industrial Group for Fair Utility Rates (CIGFUR II) filed a petition to intervene, which was granted by Order dated March 13, 2001.

On April 25, 2001, acting pursuant to G.S. 62-110.1 and the Public Staff's Proposed Rule R8-63, Progress Energy Ventures, Inc. (Energy Ventures), filed an application for certificates of public convenience and necessity to construct 640 megawatts of generating facilities in Richmond County and 640 megawatts of generating facilities in Rowan County. Energy Ventures filed supporting testimony of Robert F. Caldwell. Energy Ventures requested that Docket E-2, Sub 777 be closed and that a new docket be opened for the application.

On May 10, 2001, Rowan Generating Company, LLC, a subsidiary of Entergy Power Generation Corporation, filed a petition to intervene, which was granted by Order dated May 23, 2001.

On June 25, 2001, at the Commission's Staff Conference, the Public Staff recommended that the Commission grant the request to close Docket No. E-2, Sub 777 and issue a procedural order in Docket EMP-5, Sub 0. The Public Staff noted that the proposed generating facilities in this docket are additions to facilities at the two sites for which CP&L currently holds certificates and that CP&L had applied to transfer these existing certificates to subsidiaries of Energy Ventures in Docket E-2, Sub 778.

On June 28, 2001, the Commission issued an order which closed Docket E-2, Sub 777 and opened Docket EMP-5, Sub 0, required public notice of Energy Ventures' application, and scheduled a public hearing. The order established a procedural schedule leading up to hearing.

On July 19, 2001, CIGFUR II filed a petition to intervene in this new docket, which was granted by Order dated August 8, 2001. On July 25, 2001, the Attorney General filed a notice of intervention in this docket pursuant to G.S. 62-20.

On July 27, 2001, the Public Staff filed the direct testimony of Thomas S. Lam and Rowan Generating Company, LLC filed the direct testimony of J. Bradley Williams. On August 7, 2001, Energy Ventures filed the rebuttal testimony of Robert F. Caldwell.

Rowan Generating Company, LLC withdrew its intervention on August 15, 2001.

The hearing was held as scheduled on August 16, 2001. At the hearing, the testimony and exhibits of Robert F. Caldwell for Energy Ventures and the testimony of Thomas S. Lam for the Public Staff were entered into the record. No other evidence was presented.

Following the hearing, on September 12, 2001, the Commission extended the deadline for proposed orders in this docket until after issuance of the order in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, in light of the connection between the two proceedings. On October 1, 2001, the Commission issued an order in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1 which approved CP&L's request to transfer its existing certificate for certain generating facilities in Rowan County to a subsidiary of Energy Ventures, but denied CP&L's request to transfer its certificate for the Richmond generating facilities. In response to that order, Energy Ventures filed a proposed order in this docket asking that the new certificate for the additional facilities in Richmond County be issued to CP&L, instead of Energy Ventures. CUCA filed response raising concerns about this proposal. The Commission will not address at this time the request for a certificate for additional facilities in Richmond County; the Commission will issue a subsequent order addressing that aspect of this docket. The present order deals only with the request for a certificate for additional facilities in Rowan County.

ELECTRIC MERCHANT PLANT - CERTIFICATE

Based on the 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. Energy Ventures is a wholly owned subsidiary of Progress Energy, Inc. Progress Energy, Inc. is a registered public utility holding company that also owns CP&L and North Carolina Natural Gas Corporation. Energy Ventures is a subsidiary created by Progress Energy, Inc. to engage in the wholesale energy market in the southeastern United States, as well as unregulated businesses.

2. In compliance with G.S. 62-110.1 and Commission Rule R8-63, Energy Ventures properly filed with the Commission an application for a certificate of public convenience and necessity in which it requested the Commission to authorize the construction of 320 MW of combustion turbine generating capacity and 320 MW of combined cycle steam turbine generating capacity in Rowan County, North Carolina.

3. The certificate should be conditioned upon Energy Venture's abstaining from attempting to exercise any power of eminent domain as it relates to the proposed facilities in Rowan County.

4. The Commission identified a number of conditions that apply to merchant plant certificates in Rule R8-63(e) and (f), and these conditions are relied upon by the Commission in its determination that the public convenience and necessity are served by the construction of the proposed facilities in Rowan County.

5. The granting of the certificate in this docket is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring, or assigning the certificate and/or generating facilities.

6. Energy Ventures has made a sufficient showing of need for this proposed facility based on anticipated growth in peak demand expected in the Southeastern Electric Reliability Council (SERC) region, which includes North Carolina.

7. In Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, the Commission approved CP&L's request to transfer its certificate for certain generating facilities in Rowan County to a subsidiary of Energy Ventures. Those facilities in Rowan County will be interconnected and combined with the Rowan County facilities proposed herein. It is reasonable and appropriate to grant to Energy Ventures the requested certificate of public convenience and necessity to construct an additional 640 MW of generation in Rowan County.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural and jurisdictional in nature and was not contested by any party. It is supported by public files and records and the application, testimony and exhibits filed by the witness for Energy Ventures.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the application filed by Energy Ventures, the testimony of Energy Ventures witness Caldwell, and the testimony of Public Staff witness Lam.

G.S. 62.110.1 provides that no person may begin construction of a facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that the public convenience and necessity requires or will require such construction. The Commission initiated a rulemaking proceeding in Docket No. E-100, Sub 85 to develop a merchant plant certification rule. Energy Ventures submitted its application for a certificate for Rowan County on April 25, 2001, in conformance with the requirements of the rule as proposed at the time of filing. By Order issued May 21, 2001, the Commission adopted Rule R8-63. Public Staff witness Lam testified that Energy Ventures' application was in compliance with new Rule R8-63. Exhibit No. 2 to Energy Ventures' application contains all of the information required by Rule R8-63 for the proposed facilities in Rowan County. None of the parties to this proceeding challenged or in any way questioned Energy Ventures' compliance with the requirements of Rule R8-63 and G.S. 62.110.1 for the proposed facilities in Rowan County. Therefore, the Commission finds that Energy Ventures' application is complete and in compliance with G.S. 62.110.1 and Commission Rule R8-63 for the proposed facilities in Rowan County.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 3

In response to questions asked by the Commission concerning a condition that Energy Ventures disclaim any ability to exercise the right of eminent domain, counsel for Energy Ventures stated that Energy Ventures had no objection to such a restriction. Therefore, the Commission concludes that the grant of the certificate for the proposed facilities in Rowan County should be conditioned upon Energy Venture's abstaining from attempting to exercise any power of eminent domain as it relates to this proposed facility.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

This finding of fact incorporates provisions of Commission Rule R8-63(e) and (f), adopted in Docket No. E-100, Sub 85. These provisions require, among other things, that the certificate shall be subject to revocation under specified circumstances, that the certificate must be renewed if construction is not begun in two years, that Energy Ventures must notify the Commission of plans to sell or transfer or assign the certificate and facility, and that Energy Ventures shall submit to the Commission annual progress reports and any revisions in cost estimates until construction is completed. All the provisions of Rule R8-63(e) and (f) shall apply to this certificate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

In the Commission's recent proceeding to adopt Commission Rule R8-63, Docket No. E-100, Sub 85, the Public Staff commented that the Commission needs some continuing authority as to how merchant plants are being used, even after the certificate is issued and construction completed. The Public Staff proposed that such continuing authority could be achieved by issuing the certificate with a condition that any subsequent transfer be subject to Commission approval. The Commission's May 21, 2001 order adopting a merchant plant certification rule wrote into Rule R8-63(e)(4) the requirement that a certificate holder must give notice of any plans to sell, transfer or assign the certificate and facility, but the Commission left the issue of whether a certificate holder must get Commission approval of a sale, transfer or assignment for consideration in future, individual certificate cases.

The Commission concludes that it is appropriate to address in this case the issue of whether a certificate holder should get Commission approval of a sale, transfer or assignment. The Commission is responsible for staying informed as to the state of electric generation in North Carolina and ensuring the adequacy and reliability of public utility service. Merchant plants provide public utility service, directly or indirectly, and the Commission must maintain some continuing monitoring and oversight as to them. Further, it is important for planning purposes and for preventing market abuses that the Commission have more than just notice when a merchant plant is sold, transferred or assigned. The Commission must be able to act on this notice if it is to perform its duties under law. Therefore, the Commission will require, as a continuing condition of the merchant plant certificate, that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facilities.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for these findings is found in the application submitted by Energy Ventures, the testimony and exhibits of Energy Ventures witness Caldwell and the testimony of Public Staff witness Lam.

Public Staff witness Tom Lam and Energy Ventures' witness Rob Caldwell explained that the proposed generating facility to be located in Rowan County will consist of two 160 MW natural gas-fired combustion turbine generators and two 160 MW combined-cycle steam turbines to provide total gross capacity of 640 MW at average summer peak conditions. These turbines will utilize natural gas as their primary fuel and low sulfur diesel fuel oil as an alternative fuel.

By its application and the testimony of witness Caldwell, Energy Ventures stated that these new facilities are needed to meet the forecasted demand for electricity in the southeastern United States. Witness Caldwell testified that generation capacity additions are driven by market demand and traditional utility needs to maintain target reserve levels. He testified that utilities and regions need a margin of generating reserves above the generating capacity used to serve the expected load in order to assure reliable service. This reserve margin is needed to accommodate periodic maintenance requirements, refuel nuclear plants, repair failed equipment, out-of-service transmission lines and transmission constraints, and to meet higher-than-projected peak demand due to forecast uncertainty and abnormal weather.

Witness Caldwell testified that utilities categorize new resources as either "committed" or "planned." "Committed" resources include all existing resources and specifically identified new resources that the utility has committed to acquire or construct. "Planned" resources include committed resources but also include resources that had been recognized as being needed in order for a utility or region to maintain an adequate reserve margin but have not been specifically identified and no commitments have been made. For example, witness Caldwell testified that CP&L's committed resources in 2003 are 14,217 MW while its planned resources are 14,532 MW. Similarly, witness Caldwell testified that according to Duke Power Company's September 2000 Annual Plan, its committed resources in 2003 are 20,350 MW while its planned resources are 21,420 MW. Based on the Southeastern Electric Reliability Council (SERC) 2000 EIA-411 Report, "Regional Electricity Supply and Demand Projections," for 2003, approximately 7,000 MW of the total planned resources in the SERC region, which includes most of the southeastern United States, are uncommitted. By 2009, the level of uncommitted resources increases to over 12,500 MW. He testified that the 7,000 MW to nearly 13,000 MW of uncommitted planned resources for the 2003 through 2009 period represents the market or need for the Rowan County generation facilities proposed by Energy Ventures. Finally, witness Caldwell testified that the Rowan County sites would provide economic and reliable capacity and energy to serve a portion of the significant new generating capacity requirements in the SERC region, including the Carolinas.

Public Staff witness Lam agreed with Energy Venture's witness Caldwell that Energy Ventures had shown a need for the proposed facilities and that Energy Ventures should be granted certificates to construct the proposed facilities. No other party presented any evidence on this issue.

The Commission concludes that Energy Ventures has made a sufficient showing of public need for the proposed generating facilities in Rowan County.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is found in the application of Energy Ventures, the testimony of Energy Ventures witness Rob Caldwell, the testimony of Public Staff witness Tom Lam, and the Commission's Order issued September 10, 2001 in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1.

In Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, CP&L asked the Commission to allow it to transfer its existing certificates for generating facilities in Richmond County and Rowan County to subsidiaries of Energy Ventures. Both witness Lam and witness Caldwell explained that in some cases the new steam turbine generators will be matched with, and connected to, existing combustion turbines owned by CP&L at these sites. Therefore, Public Staff witness Lam explained that awarding the certificates for the additional facilities requested in this proceeding is related to approval of the transfer of the certificates in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1.

By Order issued October 1, 2001, the Commission allowed CP&L to transfer its existing certificate for the generating facilities in Rowan County to a subsidiary of Energy Ventures, but denied CP&L's request to transfer its existing certificate for the Richmond facilities. Given that the proposed facilities will be interconnected with the existing certificated facilities at the Rowan County site and that Energy Ventures has met the requirements of G.S. 62-110.1 and Commission Rule R8-63, the Commission will grant the certificate associated with the proposed new Rowan County generating facilities to Energy Ventures. Granting Energy Ventures the requested certificate to construct additional facilities at the Rowan County site is consistent with the Commission's Order in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1 approving the transfer of the certificate for the existing facilities in Rowan County to a subsidiary of Energy Ventures and will result in all the facilities at the Rowan site being certificated to Energy Ventures or its subsidiary. The Commission notes that none of the parties to this proceeding objected to the granting of the certificate for the new Rowan County facilities to Energy Ventures.

IT IS, THEREFORE, ORDERED as follows:

1. That a certificate of public convenience and necessity should be issued to Energy Ventures for the construction of the 320 MW of combustion turbine merchant plant generating facility and 320 MW of combined cycle steam turbine merchant plant generating facility in Rowan County, and the same is attached hereto as Appendix A;

2. That the certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and the certificate is conditioned upon Energy Venture's abstaining from attempting to exercise any power of eminent domain in connection with these facilities;

3. That the certificate is subject to the conditions in Rule R8-63(e) and (f); and

4. That the certificate is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facilities.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

sk112001.01

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. EMP-5, SUB 0

PROGRESS ENERGY VENTURES, INC.
411 Fayetteville Street Mall
Raleigh, North Carolina 27602

is hereby granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of a dual-fueled, combustion turbine and steam turbine generator merchant plant generating facility with a nominal rating of 640 MW

located

at a site bounded by U.S. Route 70 and State Roads 1951, 1952 and 801 approximately nine miles west of Salisbury, in Rowan County, North Carolina,

subject to Commission Rule R8-63(e) and (f) and all orders, rules, and regulations that have been and may hereinafter be lawfully made by the North Carolina Utilities Commission. In addition, this Certificate is not intended to confer the power of eminent domain under North Carolina law for construction of this facility and Progress Energy Ventures, Inc., shall abstain from attempting to exercise any power of eminent domain pursuant to this Certificate. This Certificate is also conditioned upon the requirement that the certificate holder, including all future holders of this certificate, must get the approval of the Commission before selling, transferring or assigning the certificate and/or generating facility.

ISSUED BY ORDER OF THE COMMISSION
This the 20th day of November, 2001

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

DOCKET NO. EMP-5, SUB 0
DOCKET NO. E-2, SUB 777

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Progress Energy Ventures, Inc., for a Certificate of Public Convenience and Necessity to Construct 640 MW of Generation Facilities in Richmond County and 640 MW of Generation Facilities in Rowan County In the Matter of Application of Carolina Power & Light Company for a Certificate of Public Convenience and Necessity to Construct 640 MW of Generation Facilities in Richmond County and 640 MW of Generation Facilities in Rowan County	)	ORDER GRANTING CERTIFICATE TO CAROLINA POWER & LIGHT COMPANY FOR GENERATING FACILITIES IN RICHMOND COUNTY

HEARD: Thursday, August 16, 2001, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Lorinzo L. Joyner, Presiding, and Commissioners Judy Hunt, J. Richard Conder, Robert V. Owens, Jr., Sam J. Ervin, IV, and James Y. Kerr, II

APPEARANCES:

For Progress Energy Ventures, Inc. and Carolina Power & Light Company:

Len S. Anthony, Manager, Regulatory Affairs, Post Office Box 1551, Raleigh, North Carolina 27602-1551

For the Public Staff:

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

For the North Carolina Attorney General:

Leonard G. Green, Assistant Attorney General, N.C. 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 1735, Two Hannover Square 434 Fayetteville Street Mall, Raleigh, North Carolina 27601

ELECTRIC MERCHANT PLANT - CERTIFICATE

For the Carolina Industrial Group for Fair Utility Rates:

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

BY THE COMMISSION: On November 30, 2000, in Docket E-2, Sub 777, Carolina Power & Light Company (CP&L) filed preliminary plans pursuant to Commission Rule R8-61 to construct an additional 635 megawatts of electric generating facilities at its Richmond County generation site and 626 megawatts of electric generating facilities at its Rowan County generation site, to achieve the full expansion capability of both sites.

On February 21, 2001, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by Order dated February 27, 2001. On March 9, 2001, Carolina Industrial Group for Fair Utility Rates (CIGFUR II) filed a petition to intervene, which was granted by Order dated March 13, 2001.

On April 25, 2001, acting pursuant to G.S. 62-110.1 and the Public Staff's proposed Rule R8-63 (the Commission's new Rule on certificating merchant plant generating facilities), Progress Energy Ventures, Inc. (Energy Ventures), filed an application for certificates of public convenience and necessity to construct 640 megawatts of merchant plant generating facilities in Richmond County and 640 megawatts of merchant plant generating facilities in Rowan County. Energy Ventures filed the supporting testimony of Robert F. Caldwell. Energy Ventures requested that Docket E-2, Sub 777 be closed and that a new docket be opened for the merchant plant application.

On June 25, 2001, at the Commission's Staff Conference, the Public Staff recommended that the Commission grant the request to close Docket No. E-2, Sub 777 and issue a procedural order in new Docket EMP-5, Sub 0. The Public Staff noted that the proposed generating facilities in this docket are additions to facilities at the two sites for which CP&L has certificates and that CP&L had applied to transfer these existing certificates to subsidiaries of Energy Ventures in Docket E-2, Sub 778 and EMP-5, Sub 1.

On June 28, 2001, the Commission issued an order which closed Docket E-2, Sub 777, opened Docket EMP-5, Sub 0, and scheduled a public hearing. The order established a procedural schedule leading up to the hearing and required that public notice of the application be published in Rowan and Richmond Counties.

On July 19, 2001, CIGFUR II filed a petition to intervene in this new docket, which was granted by Order dated August 8, 2001. On July 25, 2001, the Attorney General filed a notice of intervention in this docket pursuant to G.S. 62-20.

On July 27, 2001, the Public Staff filed the direct testimony of Thomas S. Lam. On August 7, 2001, Energy Ventures filed rebuttal testimony.

The hearing was held as scheduled on August 16, 2001. At the hearing, the testimony and exhibits of Robert F. Caldwell for Energy Ventures and the testimony of Thomas S. Lam for the Public Staff were entered into the record. No other evidence was presented. Affidavits of publication were filed indicating that public notice had been given as ordered by the Commission. No public witnesses appeared.

Following the hearing, on September 12, 2001, the Commission extended the deadline for proposed orders until after issuance of the order in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, in light of the connection between the certificate proceedings and the transfer proceedings. On October 1, 2001, the Commission issued an order in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1 which approved CP&L's request to transfer its existing certificate for certain generating facilities in Rowan County to a subsidiary of Energy Ventures, but denied CP&L's request to transfer its certificate for the Richmond County generating facilities. In response to that order, Energy Ventures filed a proposed order in this docket asking that a merchant plant certificate for the additional facilities in Richmond County be issued to CP&L, instead of Energy Ventures. CUCA filed a response raising concerns about this proposal on October 25, 2001.

On November 20, 2001, the Commission issued an Order in Docket No. EMP-5, Sub 0 which granted a certificate of public convenience and necessity to Energy Ventures for construction of 320 MW of combustion turbine merchant plant generating capacity and 320 MW of combined cycle steam turbine merchant plant generating capacity in Rowan County. The Order noted that the Commission would issue a subsequent order addressing the request for a certificate for construction of additional facilities in Richmond County.

On November 29, 2001, Energy Ventures, CP&L, and the Public Staff filed a Joint Motion Regarding Additional Facilities. By this motion, these three parties asked the Commission to re-open Docket No. E-2, Sub 777; to consolidate it with Docket No. EMP-5, Sub 0; and to grant CP&L a certificate of public convenience and necessity pursuant to Commission Rule R8-61 (not Commission Rule R8-63) for construction of 160 MW of combustion turbine generating capacity and 160 MW of heat recovery steam turbine generating capacity at the Richmond County site. CP&L and the Public Staff filed verifications of the allegations of the Joint Motion on December 6, 2001. B Mitchell Williams verified the motion for CP&L; Michael C. Maness verified it for the Public Staff.

CUCA filed a letter on December 3, 2001, stating that it "is not opposed to the Joint Motion." The Attorney General filed a statement of position to the same effect on December 4, 2001. CIGFUR II has made no filing.

Based on the preliminary plans, the application, the testimony and exhibits received into evidence at the hearing, the verified statements in the Joint Motion, and the record as a whole in these two dockets, the Commission makes the following:

FINDINGS OF FACT

1. CP&L is duly organized as an electric public utility under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. CP&L is engaged in the business of generating, transmitting, distributing and selling electric power in its assigned territory in North and South Carolina. CP&L is a wholly owned subsidiary of Progress Energy, Inc. Progress Energy, Inc. is a registered public utility holding company that also owns Energy Ventures and North Carolina Natural Gas Corporation.

2. On November 30, 2000, in Docket E-2, Sub 777, CP&L filed preliminary plans pursuant to Commission Rule R8-61 to construct an additional 635 megawatts of electric generating facilities at its Richmond County site. Subsequently, on April 25, 2001, Energy Ventures filed an application, that was designated by the Commission as Docket EMP-5, Sub 0. The Energy Ventures application was filed pursuant to the Commission's merchant plant Rule R8-63, and it requested a certificate of public convenience and necessity for construction of 320 MW of combustion turbine generating capacity and 320 MW of combined cycle steam turbine generating capacity at the Richmond County site. By the present Order, the Commission will reopen Docket E-2, Sub 777, consolidate it with Docket EMP-5, Sub 0, and substitute CP&L for Energy Ventures as the applicant for the certificate of public convenience and necessity for new construction in Richmond County. Since CP&L is a public utility, the certificate will be deemed as one pursuant to Commission Rule R8-61, not the merchant plant Rule R8-63.

3. The original proposal was to construct approximately 640 MW of electric generation facilities at the CP&L generation site in Richmond County beginning in October 2001. The Richmond County facilities will consist of both combustion turbines and heat recovery steam turbines. The new facilities will be dual-fueled, capable of operating on both oil and gas, and they will supply peaking and intermediate electrical capacity and energy. The facilities will interconnect with the CP&L transmission system.

4. In some cases, a new steam turbine generators would be coupled with existing combustion turbines to create a combined cycle unit. Thus, the proposal of Energy Ventures was dependent on the transfer of the certificate for existing CP&L facilities to Energy Ventures, so ownership would be the same.

5. Following the hearing, the Commission issued an Order on October 1, 2001, in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, denying CP&L's request to transfer its certificate for the existing Richmond County facilities. This led to the request that the Commission grant the certificate for the new facilities to CP&L.

6. CP&L's present request in this proceeding is for a certificate of public convenience and necessity to construct 160 MW of combustion turbine generating capacity and 160 MW of heat recovery steam turbine generating capacity at its Richmond County site.

7. The need for this new construction is demonstrated in CP&L's most recent Resource Plan which shows the need for the additional Richmond County facilities to serve CP&L's system load. The Plan includes capacity of 320 MW to be added in 2003.

8. In October 2000, CP&L issued a Request for Proposals (RFP) as part of its resource planning process in which it solicited additional generating resources to be added in the year 2003. According to CP&L's analysis, the results of the RFP showed the additional facilities at the Richmond County site to be cost-effective for meeting system resource needs. The Public Staff believes that the additional Richmond facilities appear to be the most cost-effective option for meeting system needs.

9. The estimated installed construction cost for simple cycle and combined cycle combustion turbine generators was filed as part of the Energy Ventures application. The reasonable amount and

appropriate accounting and ratemaking treatment of the actual construction costs of the capacity certificated herein remain subject to Commission determination in future proceedings, and CP&L shall file a report with the Commission detailing the final actual construction costs of the project.

10. The proposed new facilities in Richmond County are for the public convenience and necessity as required by G.S. 62-110.1 and are consistent with CP&L's resource plan. The proposed facilities are necessary in order for CP&L to meet its electric service obligations, are the most cost-effective resource available, and are consistent with the Commission's plan for expansion of electric generating capacity. It is reasonable and appropriate to grant CP&L a certificate of public convenience and necessity to construct an additional 320 MW of generating capacity in Richmond County.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

This finding of fact is essentially informational, procedural and jurisdictional in nature and was not contested by any party. It is supported by the filings herein and the records of the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is contained in the filings in these two dockets, in particular, the preliminary plans filed by CP&L, the application filed by Energy Ventures, and the Joint Motion of Energy Ventures, CP&L, and the Public Staff.

This finding of fact traces the procedural journey of the application. G.S. 62.110.1 provides that no person may begin construction of a facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service without first obtaining from the Commission a certificate that the public convenience and necessity requires or will require such construction. Commission Rule R8-61 was adopted to implement this statute, with a particular focus on certificates granted to public utilities. The Commission recently adopted Rule R8-63, which also implements G.S. 62-110.1 but focuses on the certification of merchant plant facilities.

CP&L originally filed preliminary information for new Richmond County facilities, as required by Rule R8-61. This was filed in a CP&L docket, Docket No. E-2, Sub 777. Subsequently, it was decided that Energy Ventures, not CP&L, would build these facilities. Energy Ventures submitted an application for a certificate for the Richmond County facilities on April 25, 2001, and the Energy Ventures application was filed in compliance with Rule R8-63. This application was designated a merchant plant docket, Docket No. EMP-5, Sub 0. Subsequently, it was decided that CP&L, not Energy Ventures, would build these facilities. This change was prompted by the Commission's denial of the transfer of existing CP&L facilities at the Richmond County site from CP&L to Energy Ventures. Following that decision, a proposed order was submitted asking that a merchant plant certificate for the new facilities be issued to CP&L. No action had been taken on that proposal when the final transmogrification of the docket came in the Joint Motion of November 29, 2001. The Joint Motion proposed that Docket E-2, Sub 777 be re-opened and that CP&L be granted a certificate as a public utility. The Commission hereby grants the motion to re-open Docket E-2, Sub 777 and to consolidate it with Docket EMP-5, Sub 0. The Commission will substitute CP&L as the applicant herein, based on the record already assembled as supplemented by the verified allegations of the Joint Motion.

EVIDENCE AND CONCLUSION FOR FINDINGS OF FACT NOS. 3 - 6

The evidence for these findings is found in the preliminary plans filed by CP&L, the application filed by Energy Ventures, the testimony and exhibits of witnesses Caldwell and Lam and the verified Joint Motion of Energy Ventures, CP&L, and the Public Staff.

The new facilities proposed herein will be dual-fueled, capable of operating on both oil and gas, and they will supply peaking and intermediate electrical capacity and energy. The new Richmond County facilities will interconnect with the CP&L transmission system. Witness Caldwell testified to the original proposal by which Energy Ventures proposed to construct approximately 640 MW of electric generation facilities at the CP&L site in Richmond County, with construction scheduled to begin in October 2001 and commercial operation scheduled for 2003-2005. The Richmond County facilities would consist of one 160 MW combustion turbine generator and three 160 MW heat recovery steam turbine generators. Each steam turbine generator will be connected to two combustion turbine generators, creating a 480 MW combined-cycle unit. One of the new steam turbine generators might be matched with one existing and one new combustion turbine, or one of the new steam turbine generators might be coupled with two existing combustion turbines. Thus, Caldwell testified that the new steam turbine generators cannot be installed unless and until the Commission allowed CP&L to transfer its certificates for existing facilities to Energy Ventures. Public Staff witness Lam agreed that awarding the certificates for the new facilities was related to approval of the transfer.

Following the hearing, by Order issued on October 1, 2001, in Docket Nos. E-2, Sub 778 and EMP-5, Sub 1, the Commission denied CP&L's request to transfer its certificate for the existing Richmond County facilities. This led to the request that the Commission grant the new certificate in this docket to CP&L, so that new CP&L facilities can be matched to existing CP&L facilities. Granting the certificate to CP&L under Rule R8-61, rather than under Rule R8-63, is consistent with the original request filed by CP&L in Docket No. E-2, Sub 777.

One change to the original proposal was contained in the Joint Motion. CP&L now requests that the Commission only issue a certificate at this time for one combustion turbine and one steam turbine generator at the Richmond County site. These facilities total 320 MW and are needed by 2003. CP&L makes this change due to potential changes in its load forecast as a result of changing economic forecasts and the resulting impact on resource needs. Further, the change is due to the fact that CP&L's analysis is not yet complete for potential resource options beyond 2003. CP&L states that it will renew its request for additional units at the Richmond County site at some future time, based upon resource plan needs and an evaluation of alternatives. Therefore, CP&L's present request in this proceeding is for a certificate of public convenience and necessity to construct 160 MW of combustion turbine generating capacity and 160 MW of heat recovery steam turbine generating capacity in Richmond County.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 - 8

The evidence for these findings is found in the preliminary plans filed by CP&L and the verified Joint Motion of Energy Ventures, CP&L, and the Public Staff.

CP&L's most recent Resource Plan, filed with the Commission on August 31, 2001, continues to show the need for the Richmond County additions to serve CP&L's system load. Specifically, the Resource Plan includes a combustion turbine generator and a steam turbine generator with a combined capacity of 320 MW to be added at Richmond County in 2003. The plan also includes an additional 162 MW steam turbine generator at Richmond County in 2004. Without these additions, the 2003 reserve margin as calculated in the Resource Plan would drop from 15.2% to 12.7%, and the 2004 reserve margin from 14.2% to 10.4%.

CP&L, as part of its resource planning process, issued an RFP in October 2000 soliciting additional generating resources to be added in the year 2003, the same year the first two additional units in Richmond County are scheduled to be placed in-service. Six bidders submitted offers. After initial review, CP&L evaluated a total of four bids submitted by three of the bidders. According to CP&L's analysis, the results of the RFP show additional capacity at the Richmond County facility to be cost-effective for meeting system resource needs. As part of its investigation in Docket Nos. E-2, Sub 778, E-2, Sub 777, and EMP-5, Sub 0, the Public Staff reviewed the results of this RFP. While the Public Staff does not agree with all of the assumptions and methods used by CP&L to analyze the results of the RFP, the Public Staff does believe that the additional Richmond County units currently appear to be the most cost-effective option for meeting system needs.

Based upon the need for the resources to meet system load and the results of the RFP, CP&L proposes to construct and place in service one additional combustion turbine and one additional steam turbine generator (approximately 160 MW each) at its Richmond County site in 2003. CP&L therefore requests the certificates for this additional capacity in this proceeding. Due to potential changes in CP&L's load forecast as a result of changing economic forecasts, and the resulting impact on resource needs, as well as the fact that the analysis of other potential options is not yet complete, CP&L agrees with the Public Staff that the Commission should only issue a certificate for the 2003 units -- one combustion turbine and one steam turbine generator, for a total of 320 MW -- at the Richmond County site at this time. CP&L will renew its request for additional units at Richmond County at some time in the future, based upon resource plan needs and an evaluation of alternatives.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9 - 10

The evidence for these findings is found in the preliminary plans filed by CP&L, the application filed by Energy Ventures, the testimony and exhibits of witnesses Caldwell and Lam, and the verified Joint Motion of Energy Ventures, CP&L, and the Public Staff.

G.S. 62-110.1(e) provides that an applicant shall file an estimate of construction costs in such detail as the Commission may require and that no certificate shall be granted unless the Commission has approved the estimate and made a finding that such construction will be consistent with the Commission's plan for expansion of electric generating capacity. Further, G.S. 62-110.1(f) provides that the Commission shall maintain an ongoing review of construction and that the applicant shall submit annual progress reports and any revisions in cost estimates for construction.

Energy Ventures filed estimated installed construction costs for simple cycle and combined cycle combustion turbine generators as part of its application. In the Joint Motion, CP&L agreed that any Commission Order granting it a certificate in this docket should include the following provisions:

(a)That the reasonable amount and appropriate accounting and ratemaking treatment of the actual construction costs of the capacity certificated remain subject to Commission determination in future ratemaking or other proceedings; and

(b)That, because the results of CP&L's RFP are based on estimated self-build construction costs, and consistent with the monitoring authority conferred upon the Commission by G.S. 62-110.1(f), CP&L shall file with the Commission a report detailing the final actual construction costs of the project. Said filing may be made under seal and provided to the parties to this proceeding subject to an appropriate confidentiality agreement.

The Commission agrees that such provisions are appropriate and shall be considered conditions of the certificate herein.

The Joint Motion also included a condition that if CP&L has not begun construction within two years of the date of this Order, it shall file a justification for continuing to hold this certificate. The Commission concludes that this is also appropriate.

Based on all of the proceedings in these dockets and the findings and conclusions made and the conditions ordered hereinabove, the Commission concludes that the proposed new facilities in Richmond County are for the public convenience and necessity as required by G.S. 62-110.1 and are consistent with CP&L's resource plan. The proposed facilities are necessary in order for CP&L to meet its electric service obligations, are the most cost-effective resource available, and are consistent with the Commission's plan for expansion of electric generating capacity. It is reasonable and appropriate to grant CP&L a certificate of public convenience and necessity to construct an additional 320 MW of generating capacity in Richmond County.

IT IS, THEREFORE, ORDERED as follows:

1. That Docket E-2, Sub 777 is re-opened and consolidated with Docket EMP-5, Sub 0 and CP&L is substituted as the applicant herein;

2. That a certificate of public convenience and necessity should be issued to CP&L for construction of 160 MW of combustion turbine generating capacity and 160 MW of heat recovery steam turbine generating capacity in Richmond County, and the same is attached hereto as Appendix A;

3. That the reasonable amount and appropriate accounting and ratemaking treatment of the actual construction costs of the capacity certificated herein shall remain subject to Commission determination in future proceedings;

4. That CP&L shall file a report with the Commission detailing the final actual construction costs of the project and said filing may be made under seal and provided to the parties to this proceeding subject to an appropriate confidentiality agreement; and

5. That if CP&L has not begun construction within two years of the date of this Order, it shall file a justification for continuing to hold this certificate.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg121101.02

Appendix A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 777
DOCKET NO. EMP-5, SUB 0

CAROLINA POWER & LIGHT COMPANY
411 Fayetteville Street Mall
Raleigh, North Carolina 27602

is hereby granted this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for construction of approximately 160 MW of
heat recovery steam turbine generating capacity and 160 MW
of combustion turbine generating capacity

located

approximately 3 miles south of the Town of Hamlet near the
intersection of State Road 177 and State Route 1990 in
Richmond County, North Carolina

subject to the reporting requirements of G.S. 62-110.1(f) and all other orders,
rules, regulations and conditions now or hereafter lawfully made by the
North Carolina Utilities Commission.

Should Carolina Power & Light not begin construction of this capacity within two(2) years of the date of issuance of this Certificate, Carolina Power & Light is required to file a justification with the North Carolina Utilities Commission explaining why its retention of the Certificate is appropriate.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

NATURAL GAS - ACCOUNTING

DOCKET NO. G-9, SUB 453

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Piedmont Natural Gas	)	ORDER ON REQUEST
Company, Inc., for Approval of Special	)	FOR SPECIAL ACCOUNTING
Accounting Procedures	)	TREATMENT

BY THE COMMISSION: On September 24, 2001, Piedmont Natural Gas Company, Inc. (Piedmont), filed a request for approval of special accounting treatment of certain costs related to uncollectible accounts during last winter. Piedmont states that high gas prices and colder-than-normal weather during November and December 2000 led to significantly higher gas bills than those for the previous winter. Piedmont took steps to mitigate the impact on customers, but still many customers generated substantial past-due balances "as a result of the extended payment arrangements and various Commission rules that limit Piedmont's ability to obtain deposits and to discontinue service for non-payment of gas bills." In Piedmont's last general rate case, Docket No. G-9, Sub 428, decided in October 2000, a total of $1,722,278 was included in the cost of service for uncollectibles. During the period September 1999 through August 2000, Piedmont's uncollectibles were $2,233,344, but they increased to $5,434,621 for the period September 2000 through August 2001. The uncollectible amount of $5,434,621 for the twelve months ended August 31, 2001, was $3,662,343 in excess of the amount allowed in rates. By its request in this docket, Piedmont asks for permission to record a $3,093,564 charge to its all customers' deferred gas cost account. This represents the difference between the net amount of residential accounts written off as of August 31, 2001, and the amount of residential uncollectibles allowed in rates in Piedmont's last rate case. Any subsequent collections of these written-off accounts will be recorded in the deferred account as offsets against the $3,093,564 charge. Piedmont proposes that the uncollectibles be assigned to residential rate schedules in a later proceeding, such as the next annual gas cost prudence review.

The Chair issued an Order on October 10, 2001, requesting comments. The Commission has received comments from the Public Staff, the Attorney General, the Carolina Utility Customers Association, Inc. (CUCA), North Carolina Natural Gas Corporation (NCNG), and Public Service Company of North Carolina, Inc. (PSNC).

The Public Staff "does not oppose" the request as long as it is given no precedential effect. The Public Staff generally disfavors special accounting treatment but agrees that some form of relief is appropriate here since the Commission encouraged the LDCs to implement procedures to help residential customers pay their high gas bills last winter.

The Attorney General opposes the request as contrary to existing statutes and case law. The Attorney General says that "gas costs" recoverable under the gas cost adjustment statute, G.S. 62-133.4, do not include uncollectibles and, further, that Piedmont's proposal would amount to improper prospective ratemaking. The Attorney General says that it is not surprising that uncollectibles increased last winter since gas rates were much higher and the weather was colder than normal. The Attorney General argues that customers bore the brunt of high gas rates last winter and that Piedmont's request would increase that burden even more.

CUCA argues that there are only three ways to modify rates (a rate case, a gas cost adjustment, and a rulemaking) and that neither applies here. Piedmont is not proposing a rate case, and a rulemaking would not be appropriate due to the differences among the LDCs. A gas cost adjustment is not appropriate since uncollectibles "are clearly not costs 'related to the purchase and transportation of natural gas. . .'" Although Piedmont proposes recovery exclusively from residential customers, CUCA opposes any expansion of the gas cost adjustment statute. Further, CUCA argues that Piedmont should be required to show that the flexible payment measures encouraged by the Commission last winter actually caused an increase in uncollectibles before any recovery is allowed.

NCNG supports Piedmont's request and states that it will file a similar request. PSNC supports Piedmont's request as "a balanced approach to the recovery of associated write-offs," but PSNC does not anticipate seeking similar relief.

On October 24, 2001, Piedmont filed reply comments amending its request. In order to address the objections of the Attorney General and CUCA, Piedmont reduces its request for special accounting treatment from $3,093,564 to $2,820,028. Piedmont argues that, with this reduction, all of the amount that it now seeks to recover represents gas costs under the gas cost adjustment statute, G.S. 62-133.4.

The Attorney General filed reply comments. Among other points, the Attorney General argues that Piedmont has not shown that the increase in uncollectibles was attributable to the flexible payment measures encouraged by the Commission, that it is unfair to examine one component of rates without examining changes in other components as well, and that Piedmont's request would reverse and return to Piedmont some of the benefits that customers received through the Weather Normalization Adjustment last winter.

CUCA filed reply comments arguing that no special accounting is necessary if the amount Piedmont now seeks to recover is indeed gas costs recoverable under G.S. 62-133.4. The fact that Piedmont is seeking special accounting demonstrates that uncollectibles have never been treated as gas costs under the gas cost adjustment statute.

Piedmont made one last filing, arguing that it just wants to defer these costs now and to litigate recovery in the next gas cost prudence review, where it will bear the burden of proof and all parties will have an opportunity to be heard. Piedmont also argues that the WNA "simply has nothing whatsoever to do with this proceeding."

The Commission has considered all of the comments herein, and carefully weighed the equities as well as the law. The Commission concludes that the request for special accounting treatment should be denied. Piedmont's original petition essentially made an appeal based on equity: gas prices were high, the weather was cold, and uncollectibles went up. There are, however, serious legal obstacles to the special accounting treatment requested by Piedmont, the most fundamental of which is that the proposal focuses solely on one component of rates, without looking at changes in the utility's other expenses and revenues over the same period and without compliance with the general statutory provisions of G.S. 62-133 as construed in State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451 (1977). In response to the legal objections raised by the Attorney General and CUCA, Piedmont then amended its request. By its reply comments, Piedmont tried to bring its request within the scope of G.S. 62-133.4 by arguing that it is only trying to recover gas costs, but this argument serves to create new obstacles. If Piedmont is indeed seeking to recover gas costs under G.S. 62-133.4, no special accounting treatment is needed. Annual gas cost review proceedings are held to true-up gas costs. The fact that Piedmont is seeking special accounting treatment reflects the fact that uncollectibles have never been regarded as gas costs during the 10 years that the Commission has been holding annual gas cost review proceedings under G.S. 62-133.4. If Piedmont wants to argue that uncollectibles should be trued-up as a part of the prudence reviews, it is of course free to present that argument. Most of the dollars at issue here were charged off in the summer of 2001, which is in the test period for Piedmont's next prudence review.

The Commission recognizes that Piedmont and other LDCs were more flexible with their collection policies last winter. This flexibility was a commendable response of good corporate citizens to the emergency situation presented by unprecedented gas prices and by the heightened customer demand for the commodity due to the cold weather. It was good citizenship and good business policy to try to keep customers on the system. This flexibility was laudable -- and the Commission again expresses its appreciation -- but this flexibility does not support extraordinary rate relief not permitted by statute. We note that Piedmont's request did not focus on the amount by which their additional flexibility might have contributed to the level of recent uncollectibles. Piedmont's compliance with the Commission's request that the LDCs attempt to avoid ratepayer harm may have even reduced the amount of uncollectibles which the Company would otherwise have experienced last winter. Unfortunately, uncollectibles naturally go up when bills go up, and this is one risk from which the LDCs cannot be insulated.

IT IS, THEREFORE, ORDERED that the request for special accounting treatment filed by Piedmont on September 24, 2001, should be, and the same hereby is, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg110701.01

DOCKET NO. G-44, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Eastern North Carolina Natural Gas Company for a Certificate of Public Convenience and Necessity to Operate as a Local Distribution Natural Gas Company in the 14 Unserved Counties in Eastern North Carolina, the Exclusive Franchises to Provide Natural Gas Service to these Counties, and Natural Gas Bond Funds to Pay for the Uneconomic Portion of the Project	)	ORDER APPROVING USE OF NATURAL GAS BOND FUNDS

HEARD: Monday, April 30, 2001, at 2:00 p.m., in the Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chair Jo Anne Sanford, presiding, and Commissioners Ralph A. Hunt, Judy Hunt, Richard Conder, Sam J. Ervin, IV, and Lorinzo Joyner

APPEARANCES:

For Albemarle Pamlico Economic Development Corporation:

Thomas P. Nash, IV, Trimpi, Nash & Harmon, 200 N. Water Street, Elizabeth City, North Carolina 27909

For Eastern North Carolina Natural Gas Company:

Len S. Anthony, Manager - Regulatory Affairs, Progress Energy Services, Inc., Post Office Box 1551, Raleigh, North Carolina 27602-1551
For North Carolina Electric Membership Corporation:

Thomas K. Austin, Associate General Counsel, 3400 Summer Boulevard, Raleigh, North Carolina 27616

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

NATURAL GAS - CERTIFICATE

BY THE COMMISSION: On August 10, 1999, Carolina Power & Light Company (CP&L) and the Albemarle Pamlico Economic Development Corporation (APEC) filed a letter of intent to seek natural gas bond funds to extend natural gas service to 14 counties in eastern North Carolina. The Commission issued an order scheduling proceedings on the letter of intent.

On October 26, 1999, CP&L and APEC filed an application requesting (1) a certificate of public convenience and necessity to own and/or operate natural gas facilities as a public utility in the counties of Currituck, Camden, Pasquotank, Gates, Perquimans, Chowan, Washington, Tyrrell, Dare, Hyde, Pamlico, Jones, Carteret and Pender; (2) the exclusive franchises to provide natural gas service in these counties; and (3) sufficient natural gas bond funds to pay for the uneconomic portion of a proposed project to serve these 14 counties.

On December 6, 1999, the Commission issued an order scheduling the application for hearing on April 12, 2000, and requiring CP&L and APEC to provide public notice. Both the order and the notice provided that the April 12, 2000 hearing would only consider bond funds for the first phase of the proposed project, which would serve Currituck, Camden, Pasquotank, Gates, Perquimans, and Chowan counties (referred to as Phase I).

A motion to amend was filed on March 21, 2000, seeking to substitute a limited liability company (LLC) as the applicant for both the certificate and the gas bond funds. The motion indicated that the LLC, composed of APEC and CP&L as the only members, would be the sole owner of the certificate of public convenience and necessity and the sole applicant for gas bond funds. The LLC was subsequently identified as Eastern North Carolina Natural Gas Company, LLC (Eastern). The motion to amend was allowed at the hearing.

The case was heard as scheduled on April 12, 2000. By order issued on June 15, 2000, the Commission granted Eastern a certificate of public convenience and necessity to provide natural gas service in the 14 counties listed above and required Eastern and the Public Staff to calculate the negative net present value (NPV) for Phase I consistent with the decisions set forth in the order and to file the results of the calculation with the Commission. Regarding the remaining phases of the project, the Commission required Eastern to consult with the Public Staff and study alternative routes and designs for the system to serve the counties of Washington, Tyrrell, Dare, Hyde, Pamlico, Jones, Carteret and Pender and to submit an amended application for bond funds to support construction of the remaining phases.

On June 22, 2000, Eastern and the Public Staff filed a revised NPV calculation for Phase I of the project as required by the Commission's June 15, 2000 order. The negative NPV and the amount of bond funds requested was revised to $38,734,036. By order issued on July 12, 2000, the Commission approved funding from gas bond funds for Phase I of the project in the amount of $38,734,036.

On March 20, 2001, Eastern filed its amended application (which was clarified by letter of March 23, 2001) for Phases II through VII to serve Washington, Tyrrell, Dare, Hyde, Pamlico, Jones, Carteret and Pender Counties. The amended application requested that the Commission (1) approve the proposed route design for Phases II through VII of the project; (2) award Eastern a total of $149,582,346 (not including the previous award for Phase I) in gas bond funds and any additional gas bond funds that may become available; (3) approve a reciprocal gas transportation agreement between Eastern and North Carolina Natural Gas Corporation (NCNG); and (4) withdraw its requirement that CP&L form a separate company to hold its ownership interest in Eastern. Eastern also filed the joint testimony of Terrence Davis, Senior Vice President of Operations of NCNG and a member of Eastern's Board of Directors, and Robert P. Evans, Principal Business Analyst - Regulatory Services within the Accounting Department of Progress Energy Service Company. By Order issued on March 27, 2001, the Commission set the amended application for hearing on April 30, 2001, and provided for the prefiling of intervenor testimony and rebuttal testimony.

On April 18, 2001, and April 24, 2001, respectively, Frontier Energy, LLC (Frontier), and the North Carolina Propane Gas Association, Inc. (NCPGA), filed petitions to intervene. Eastern opposed the interventions, and the Commission denied both petitions to intervene by order issued on April 27, 2001.

On April 24, 2001, the Public Staff filed the direct testimony of Public Staff witnesses Eugene H. Curtis, Jr., Thomas W. Farmer, Jr., and James G. Hoard. Eastern filed the rebuttal testimony of John Hughes and Terrence Davis on April 26, 2001.

This matter was heard as scheduled on April 30, 2001. The Commission received the public witness testimony of Ed Congleton representing NCPGA. The Commission also received into evidence all of the prefiled direct testimony and rebuttal testimony of both Eastern and the Public Staff and all accompanying exhibits without objection. Following the hearing, by letters of May 14 and 18, 2001, Eastern filed a Services Agreement entered into between Eastern and APEC and asked the Commission to approve it. Eastern filed a proposed order on May 17, 2001, and the Public Staff filed a letter on May 21, 2001, commenting on the proposed order.

Based on the amended 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. Eastern is now a corporation organized and existing pursuant to the laws of North Carolina. Eastern's shareholders are Progress Energy, Inc. (Progress), and APEC with each shareholder owning fifty percent (50%) of Eastern's common stock.

2. The eight counties that are the subject of Phases II through VII do not have natural gas service, and they are "unserved areas" as that term is used in G.S. 62-2(9), G.S. 62-159, and Commission Rule R6-90.

3. Only economically infeasible projects can be approved for use of gas bond funds pursuant to G.S. 62-159, and an economically infeasible project is defined as one with a negative NPV. Phases II through VII are economically infeasible in that additional funds are required for an NPV of zero.

4. The route and design of the natural gas system proposed by Eastern in its amended application for Phases II through VII of the project are appropriate.

5. The total cost of Phases II through VII is $198,878,462, and the uneconomic portion of Phases II through VII of the project is $188,439,344. There is $149,582,346 of gas bond funds available to fund Phases II through VII of this project. Given that the negative NPV of Phases II through VII is $188,439,344, the Commission approves the award all of the remaining gas bond funds in the amount of $149,582,346 to Eastern. The Commission also authorizes Eastern to apply any gas bond funds not used in constructing Phase I to Phases II through VII.

6. It is appropriate for Eastern to construct the project in the order in which the phases are now numbered and for Eastern to be permitted flexibility to move unused funds from earlier phases to later phases, if savings are achieved. Progress is required to provide its contribution on a phase-by-phase basis, with $7,676,074 being contributed by it during the construction of the initial transmission and distribution systems included in Phase I, $178,836 contributed during the initial construction in Phase III, and $4,181,175 during Phase VII.

7. The reorganization of Eastern into a corporation with Progress, rather than CP&L, owning those shares of common stock not owned by APEC achieves many of the goals that the creation by CP&L of a separate company to hold CP&L's interest in Eastern would have accomplished. The Commission withdraws the requirement set forth in the June 15, 2000 order that CP&L form a separate company to hold its ownership interest in Eastern.

8. The Commission approves the rates and services to be provided pursuant to the Gas Supply and Transmission Service Contract entered into between NCNG and Eastern and filed with the Commission on April 30, 2001.

9. Due to the increase in the scope of the total project beyond that approved by the Commission for Phase I in the June 15, 2000 order, operation and maintenance expense deferrals in the amount of $15 million are approved and the deferral period is eight years.

10. It is appropriate to waive the 75% limit on reimbursements in Commission Rule R6-92(b) and to reimburse Eastern 100% of its actually incurred costs up to the negative NPV approved for Phase One. Construction activity should be carefully monitored to ensure that construction occurs in such a way that partial completion would still result in a fully functioning system.

11. The fact that Frontier has notified the Commission that it may request an additional $2,020,000 of gas bond funds to support its Ashe County project sometime in the year 2002 does not justify the Commission's holding back funds from the amount of gas bond funds to be awarded to Eastern in this proceeding.

12. Eastern should not award contracts or order pipe for the construction of Phases II through VII of the project until a favorable private letter ruling is received from the Internal Revenue Service (IRS), unless authorized to do so pursuant to Commission order. If the ruling is unfavorable, Eastern shall file a modified project based upon the reduced amount of bond funds that would then be available for construction.

13. Beginning July 1, 2001, Eastern shall file quarterly project reports regarding the construction of all phases of the project patterned after and containing the same type of information that NCNG included in the quarterly reports it filed for its Duplin/Onslow project. In addition, Eastern shall file an updated projected timetable in detail for the first six months from the end of the preceding quarter and more generally for the remainder of the project and an updated projected timetable for reimbursement requests in detail for the first six months from the end of the preceding quarter and more generally for the remainder of the project.

14. The Services Agreement entered into between Eastern and APEC is accepted for filing and compensation may be paid pursuant thereto.

15. The Construction, Operation and Maintenance Agreement entered into between Eastern and CP&L for the construction, operation and maintenance of the natural gas system to serve the 14 counties in Eastern's project is accepted for filing and compensation may be paid pursuant thereto. To the extent CP&L uses affiliates to perform any of the obligations under this agreement, agreements between CP&L and the appropriate affiliates shall be filed in advance and approval to pay compensation shall be obtained as required by G.S. 62-153. If any existing contract with an affiliate of Eastern or CP&L, previously filed with the Commission, is amended, Eastern shall file such amended contract within 30 days of such amendment.

16. Eastern, CP&L, NCNG, and all other affiliates that will be involved in the construction, operation, maintenance, and/or other activities of Eastern shall meet with the Public Staff to discuss the assignment of duties and responsibilities between and among entities within the Progress Energy corporate structure related to Eastern and the proper allocation and tracking of all related costs in detail. These discussions shall include the appropriate filing requirements for the expeditious processing of reimbursement requests and a methodology for dealing efficiently with any issues in controversy. Eastern and the Public Staff shall file a report on these discussions and their proposed requirements and procedures, for Commission approval, within 60 days from the date of the present order. Any request for reimbursement filed before a Commission order approving such requirements and procedures may be paid, if the Commission finds such action appropriate, subject to an adjustment to future reimbursements for amounts ultimately determined by the Commission not properly reimbursed.

17. Eastern shall keep the Commission informed as to its progress in securing a private letter ruling from the IRS and shall file the ruling with the Commission upon receipt. A further order setting forth the final negative NPV and final gas bond award amount will be necessary after Eastern has filed the ruling.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the amended application and the testimony of Eastern witnesses Davis and Evans and is uncontroverted.

Eastern witnesses Davis and Evans explained that CP&L and APEC had dissolved Eastern as a limited liability company and reorganized it as a corporation with Progress owning 50% of Eastern's common stock and APEC owning the other 50% of the common stock.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2 AND 3

The evidence supporting these findings of fact is contained in the original application and the testimony filed by Eastern witnesses for the original hearing in this docket.

The eight counties in Phases II through VII do not have any natural gas service and no party denied that they qualify as "unserved areas" within the meaning of G.S. 62-2(9), G.S. 62-159 and Commission Rule R6-90. Under the terms of G.S. 62-159, only economically infeasible projects can be approved for use of gas bond funds. An economically infeasible project is defined as one with a negative NPV. It is uncontested in this proceeding that Phases II through VII are economically infeasible in that additional funds are required for an NPV of zero.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in the amended application, the testimony of Eastern witnesses Evans and Davis, and the testimony of Public Staff witnesses Hoard, Curtis and Farmer.

Eastern witnesses Davis and Evans testified that the proposed route and system design, as set forth in the amended application, was determined by Eastern to be the most robust, productive and appropriate for Phases II through VII and that the route is very similar to the route originally proposed by Eastern in this proceeding. It involves the construction of a backbone twelve-inch natural gas pipeline beginning in the town of Ahoskie proceeding in a southerly direction down Highway 13 to Highway 17 and proceeding south down to Wilmington. Lateral lines extending in an eastward direction along highway rights-of-way branch off of the backbone system to the eight unserved counties. Eastern explained that this system is the most appropriate and robust for a number of reasons. First, this route provides Eastern a direct connection to an interstate pipeline, i.e., Transcontinental Gas Pipe Line Corporation's lateral line that terminates in Ahoskie. Therefore, Eastern is not dependent upon any other entity for the delivery of gas to its system. Secondly, this twelve-inch backbone system provides Eastern the ability to serve potentially new large industrial customers without the need to significantly expand the delivery capability of its supplier or the need to significantly expand its own system. These two factors are particularly important given that the overall goal of the establishment of the gas bond funds is to encourage economic development. It is believed that new business and industrial customers are more likely to locate on a system that is robust and capable of serving their needs without significant upgrades. Thirdly, a route design that breaks the Eastern system into pieces with each piece dependent upon a separate NCNG pipeline (which is what all of the alternative route studies do to varying degrees) complicates the operation of the system as well as the procurement of supplies. Fourthly, the witnesses explained that the backbone system extending from Ahoskie down to Wilmington will interconnect with the four NCNG pipelines that terminate in Eastern North Carolina, thereby allowing these lines to be supplied natural gas by Eastern's backbone system as well as providing Eastern with an alternative supply of gas for its system. This benefits both Eastern and NCNG and strengthens the natural gas delivery system for all of eastern North Carolina. Finally, witnesses Davis and Evans explained that economic analyses demonstrated that it is not cost-effective to enhance NCNG's system to supply gas to Eastern's system.

The witnesses emphasized that the proposed route follows established highway rights-of-way that extend from practically the Virginia border almost to the South Carolina border. It is believed that this area, as well as the routes followed by the lateral distribution pipes, represent areas where economic development is most likely to occur. The witnesses explained that creating "islands" of various portions of the Eastern system, which would result if the backbone route is not constructed, undermines this economic development opportunity.

No other party presented any evidence on this matter and Eastern's position was uncontroverted. Therefore, the Commission finds that the proposed route as set forth in the amended application creates the most value for the gas bond funds invested and is the most appropriate route to be constructed to serve not only the 14 unserved counties but also eastern North Carolina.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is found in the amended application, the testimony of Eastern witnesses Davis and Evans, and the testimony of Public Staff witnesses Hoard, Curtis and Farmer.

These witnesses testified that the amended application contained a calculation of the negative NPV for the proposed route for Phases II through VII consistent with the Commission's June 15, 2000 order, assuming that the gas bond funds are found not to be taxable. These calculations demonstrated that the total cost for Phases II through VII is $198,878,462 and that the negative NPV is $188,439,344. Of the $200 million of gas bond funds authorized by the General Assembly, the Commission has previously awarded $50,417,653. This amount includes the $38,734,036 awarded by the Commission to Eastern to construct Phase I of the project. Thus, the total amount of gas bond funds available at this time for Phases II through VII is $149,582,346.

Given that Eastern has demonstrated that the negative NPV of Phases II through VII is $188,439,344 and that no other party has challenged or in any way disputed this amount, the Commission finds that it should award Eastern all of the remaining gas bond funds, in the amount of $149,582,346 to construct Phases II through VII of this project. The Commission also authorizes Eastern to apply any gas bond funds not used in constructing Phase I to Phases II through VII.

Eastern has also requested that the Commission award to Eastern any additional bond funds that may become available up to the total negative NPV of Phases II through VII ($188,439,344), including gas bond funds awarded to other gas expansion projects if such projects ultimately do not need all of the bond funds awarded to them. The Commission concludes that it would be inappropriate to award Eastern any claim to funds that the Commission does not now have available to award, and that it would likewise be inappropriate to award Eastern any claim to funds that the Commission has already awarded to other companies. If any additional funding for natural gas expansion becomes available in the future from any source, Eastern -- like any other qualified applicant -- may file an application for such funds at that time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding of fact is found in the amended application, the testimony of Eastern witnesses Davis and Evans, and the testimony of Public Staff witnesses Hoard, Curtis and Farmer.

It is appropriate for Eastern to construct the project in the order in which the phases are now numbered and for Eastern to be permitted flexibility to move unused funds from earlier phases to later phases, if savings are achieved. Progress is required to provide its contribution on a phase-by-phase basis, with $7,676,074 being contributed by it during the construction of the initial transmission and distribution systems included in Phase I, $178,836 contributed during the initial construction in Phase III, and $4,181,175 during Phase VII.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the amended application and the testimony of Eastern witnesses Davis and Evans.

The Commission's June 15, 2000 order required CP&L to form a separate company no later than December 31, 2000, to hold its interest in Eastern. At the time of the Commission's June 15, 2000 order, Eastern was a limited liability company with APEC and CP&L as its only members. Eastern witnesses Davis and Evans explained that in order to create an organization that is most likely to receive a favorable private letter ruling from the IRS with regard to the taxability of bond funds, CP&L and APEC dissolved Eastern as a limited liability company and reorganized it as a corporation. As a result of this reorganization, Progress, the holding company that owns CP&L and NCNG, is now the owner of 50% of the common stock of Eastern and APEC is the owner of the other 50% of Eastern's common stock. This new ownership structure achieves many of the goals that the creation by CP&L of a separate company to hold CP&L's interest in Eastern would have accomplished. The Commission withdraws its requirement that a separate company be formed to hold CP&L's (now Progress') ownership interest in Eastern.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is contained in the amended application and the testimony of Eastern witnesses Davis and Evans.

The Eastern witnesses explained that in order to minimize the construction cost of the project, NCNG and Eastern have agreed to a reciprocal transportation rate that each will charge the other for transporting gas on their respective systems for the benefit of the other when the transporting party does not incur any capital costs in order to transport the gas in question. This proposed transportation rate contract was Exhibit 21 to the amended application.

The Public Staff's only concerns regarding this proposed agreement related to the fact that the contract had not yet been executed by NCNG and Eastern and that Eastern was asking the Commission to approve the actual contract, rather than simply the rates and services to be provided pursuant to the contract. On April 30, 2001, Eastern filed an amended contract that had been executed and, through the rebuttal testimony of Eastern witnesses Hughes and Davis, explained that Eastern was simply asking the Commission to approve the rates and services set forth in the contract.

No other party presented any evidence on this matter or challenged the rates or services to be provided pursuant to this contract. Therefore, the Commission approves the rates and services to be provided by NCNG and Eastern to each other as reflected in the amended contract filed on April 30, 2001.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony of Eastern witnesses Davis and Evans.

The Eastern witnesses explained that due to the increase in the scope of the project beyond that approved by the Commission for Phase I, it will be necessary to approve additional operation and maintenance expense deferrals. In the Commission's June 15, 2000 order, the Commission approved a maximum operation and maintenance expense deferral of $8 million for Phase I for a period of eight years. In order to provide for the additional phases, the Commission finds that Eastern's request to increase the operation and maintenance expense deferral to $15 million for a period of eight years is reasonable. No party objected to this proposal.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

In the June 15, 2000 order approving bond funds for Phase I, the Commission found it appropriate to waive the 75% limit on reimbursements in Commission Rule R6-92(b) and to reimburse Eastern 100% of its actually incurred costs up to the negative NPV approved for Phase I. The Commission concludes that it is appropriate to make a similar waiver for Phases II through VII. Construction activity must be carefully monitored to ensure that construction occurs in such a way that partial completion would still result in a fully functioning system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is found in the testimony of Public Staff witnesses Hoard, Curtis and Farmer and the rebuttal testimony of Eastern witnesses Davis and Hughes.

In Docket No. G-40, Subs 1 and 3, Frontier notified the Commission on April 17, 2001, that it intends to request an additional $2,020,000 in gas bond funds to support its Ashe County project sometime in the year 2002 due to unanticipated costs. The Commission took judicial notice of this in the April 27, 2001 order denying Frontier's petition to intervene. The Public Staff testified that the Commission must decide whether to reserve $2,020,000 of gas bond funds for the potential future use of Frontier.

Eastern witnesses Hughes and Davis testified that Frontier's notification that it may request approximately $2 million of gas bond funds sometime in the future is not relevant to Eastern's request for the remaining gas bond funds in the amount of $149,582,346 and that this issue should not be addressed in this proceeding. The Eastern witnesses testified that Eastern has studied, analyzed, and documented the route design and cost of the natural gas system it intends to build to serve the unserved counties in eastern North Carolina and emphasized that no one has challenged the amount of gas bond funds Eastern needs in order to construct this system. Once Eastern has shown that it is entitled to the amount of gas bond funds requested, Eastern asserts that the inquiry should end. Eastern claims that whether Frontier may seek an additional $2,020,000 sometime in 2002 to support its project is not relevant to a determination of the amount of gas bond funds to be awarded to Eastern.

The Commission concludes that Eastern's request stands on its own and is not to be weighed against a possible future request relating to another project for which the need for additional funds has not yet been proven. Eastern requested gas bond funds prior to Frontier's notice of intent and presented its case justifying an award of the entire $149,582,346 of gas bond funds remaining. It would be unfair to hold back approximately $2 million from this project and to reserve such money for the future possible use of another applicant. If any additional funding for natural gas expansion becomes available in the future from any source, Frontier -- like any other qualified applicant -- may file an application for such funds at that time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the testimony of Public Staff witnesses Hoard, Curtis and Farmer and the rebuttal testimony of Eastern witnesses Davis and Hughes.

The Public Staff recommended that Eastern be prohibited from soliciting bids for the construction of Phases II through VII until a favorable private letter ruling is received from the IRS. Eastern witnesses Hughes and Davis testified that they believe such a prohibition is inappropriate. They explained that a private letter ruling should be received within six to nine months after the filing of the request. During this time, Eastern will not be working on the later phases of the project but needs to be actively working on Phase II.

The Commission believes that both parties' positions have merit and that the proper course of action is somewhere between the two. To that end, the Commission finds that Eastern should not award contracts or order pipe for the construction of Phases II through VII of the project until a favorable private letter ruling is received from the IRS, unless allowed to do so pursuant to Commission order. With these conditions, Eastern may proceed with its work on Phases II through VII. If the ruling is unfavorable, Eastern shall file a modified project based upon the reduced amount of bond funds that would then be available for construction.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Hoard, Curtis and Farmer and the rebuttal testimony of Eastern witnesses Hughes and Davis.

In its testimony, the Public Staff recommended that the Commission require Eastern to file certain quarterly project reports. Eastern agreed that such reports would be beneficial to the Commission and recommended that these reports be patterned after the quarterly reports that have been utilized by NCNG with regard to its Duplin/Onslow expansion fund project. The Commission finds this request reasonable and appropriate and orders Eastern to begin filing such reports effective July 1, 2001.

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

The evidence supporting these findings of fact is contained in the amended application, the testimony of Public Staff witnesses Hoard, Curtis and Farmer, the rebuttal testimony of Eastern witnesses Davis and Hughes, and the records of the Commission.

In its testimony, the Public Staff witnesses expressed concern that the Construction, Operation and Maintenance Agreement entered into between CP&L and Eastern may not accurately reflect the current responsibilities of the various Progress companies. The Public Staff witnesses recommended that Eastern obtain advance approval by the Commission to pay compensation to an affiliate and that Eastern be required to file updated contracts within 90 days of the Commission's order awarding bond funds in this proceeding and to file any subsequent changes within 30 days of those changes.

Eastern witnesses Davis and Hughes testified that CP&L is the only Progress company that has any contractual obligation to Eastern, other than Progress which is an Eastern shareholder. The Eastern witnesses testified that the contractual obligations owed by CP&L to Eastern are set forth in the Construction, Operation and Maintenance Agreement which is accurate and has not been, and does not need to be, changed or revised. They further testified that this contract was filed with the Commission for its review and approval on April 25, 2001. Eastern witnesses testified that to the extent CP&L intends to utilize any affiliated company to provide any of the services necessary for CP&L to perform its obligations under this contract, CP&L will enter into an agreement with such affiliate that will be filed with the Commission pursuant to G.S. 62-153.

On May 14 and 18, 2001, Eastern filed a Services Agreement entered into between Eastern and APEC. In its letter of May 21, 2001, the Public Staff recommended that this Services Agreement be accepted for filing and that compensation may be paid pursuant thereto.

The Commission concludes that the Services Agreement entered into between Eastern and APEC should be accepted for filing and that compensation may be paid pursuant thereto. The Commission further concludes that the Construction, Operation and Maintenance Agreement entered into between Eastern and CP&L for the construction, operation and maintenance of the natural gas system to serve the 14 counties in Eastern's project should be accepted for filing and that compensation may be paid pursuant thereto. To the extent CP&L uses affiliates to perform any of the obligations under this agreement, agreements between CP&L and the appropriate affiliates shall be filed in advance and approval obtained to pay compensation as required by G.S. 62-153. If any existing contract with an affiliate of Eastern or CP&L, previously filed with the Commission, is amended, Eastern shall file such amended contract within 30 days of such amendment.

In the June 15, 2000 order approving bond funds for Phase I, the Commission stressed that proper record keeping and cost allocation procedures are "of utmost importance in the context of this proceeding to ensure that Eastern's requests for bond fund disbursements reflect accurate allocations and costs. Lack of adequate record keeping and cost allocation procedures could delay and complicate the reimbursement process." The Commission continues to feel that proper cost allocation, tracking, and record keeping are essential. To that end, the Commission requires that Eastern, CP&L, NCNG, and all other affiliates that will be involved in the construction, operation, maintenance, and/or other activities of Eastern shall meet with the Public Staff to discuss the assignment of duties and responsibilities between and among entities within the Progress Energy corporate structure related to Eastern and the proper allocation and tracking of all related costs in detail. These discussions shall include the appropriate filing requirements for the expeditious processing of reimbursement requests and a methodology for dealing efficiently with any issues in controversy. Eastern and the Public Staff shall file a report on these discussions and their proposed requirements and procedures, for Commission approval, within 60 days from the date of the present order. Any request for reimbursement filed before a Commission order approving such requirements and procedures may be paid, if the Commission finds such action appropriate, subject to an adjustment to future reimbursements for amounts ultimately determined by the Commission not properly reimbursed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of Public Staff witnesses Hoard, Curtis and Farmer.

Eastern is seeking a private letter ruling from the IRS on whether the gas bond funds would be considered taxable income. Eastern shall keep the Commission informed as to its progress in securing this private letter ruling and Eastern shall file the ruling with the Commission as soon as the ruling is received. The Commission will issue a further order in this proceeding setting forth the final negative NPV and final gas bond award amount after Eastern has filed the ruling.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed route and design for the natural gas system Eastern proposes to construct for Phases II through VII of its project, as shown in the amended application, is approved and funding from gas bond funds in the amount of $149,582,346 to support such construction is approved;

2. That Eastern is authorized to apply any gas bond funds not used in constructing Phase I to Phases II through VII of the project;

3. That Eastern shall construct the project in the order in which the phases are now numbered and that Progress shall provide its contribution on a phase-by-phase basis, with $7,676,074 being contributed by it during the construction of the initial transmission and distribution systems included in Phase I, $178,836 contributed during the initial construction in Phase III, and $4,181,175 during Phase VII;

4. That the Commission withdraws its earlier requirement that CP&L form a separate company to hold its ownership interest in Eastern;

5. That Eastern is authorized to defer a maximum of $15 million of operation and maintenance expenses that it incurs during the first eight years after it begins providing natural gas service;

6. That it is appropriate to waive the 75% limit on reimbursements contained in Commission Rule R6-92(b) and to allow Eastern to be reimbursed for 100% of its actually incurred costs up to the amount of bond funds awarded;

7. That Eastern shall not award contracts or order pipe for the construction of Phases II through VII of the project until a favorable private letter ruling is received from the IRS, unless authorized to do so pursuant to Commission order, and that if the ruling is unfavorable, Eastern shall file a modified project based upon the reduced amount of bond funds that would then be available for construction;

8. That beginning July 1, 2001, Eastern shall file quarterly project reports regarding the construction of all phases of the project patterned after and containing the same type of information that NCNG included in the quarterly reports it filed for its Duplin/Onslow expansion fund project, and, in addition, that Eastern shall file an updated projected timetable in detail for the first six months from the end of the preceding quarter and more generally for the remainder of the project and an updated projected timetable for reimbursement requests in detail for the first six months from the end of the preceding quarter and more generally for the remainder of the project;

9. That the rates and services to be provided pursuant to the Gas Supply and Transmission Service Contract entered into between NCNG and Eastern which was filed with the Commission on April 30, 2001, are approved;

10. That the Services Agreement entered into between Eastern and APEC is accepted for filing and compensation may be paid pursuant thereto;

11. That the Construction, Operation and Maintenance Agreement entered into between Eastern and CP&L for the construction, operation and maintenance of the natural gas system to serve the 14 counties in Eastern's project is accepted for filing and compensation may be paid pursuant thereto; that to the extent CP&L uses affiliates to perform any of the obligations under this agreement, agreements between CP&L and the appropriate affiliates shall be filed in advance and approval to pay compensation shall be obtained as required by G.S. 62-153; and that if any existing contract with an affiliate of Eastern or CP&L, previously filed with the Commission, is amended, Eastern shall file such amended contract within 30 days of such amendment;

12. That Eastern, CP&L, NCNG, and all other affiliates that will be involved in the construction, operation, maintenance, and/or other activities of Eastern shall meet with the Public Staff to discuss the assignment of duties and responsibilities between and among entities within the Progress Energy corporate structure related to Eastern and the proper allocation and tracking of all related costs in detail; that these discussions shall include the appropriate filing requirements for the expeditious processing of reimbursement requests and a methodology for dealing efficiently with any issues in controversy; that Eastern and the Public Staff shall file a report on these discussions and their proposed requirements and procedures, for Commission approval, within 60 days from the date of

the present order; and that any request for reimbursement filed before a Commission order approving such requirements and procedures may be paid, if the Commission finds such action appropriate, subject to an adjustment to future reimbursements for amounts ultimately determined by the Commission not properly reimbursed; and

13. That Eastern shall file revised tariffs and service rules and regulations no later than 60 days before it anticipates first offering natural gas service to customers.

ISSUED BY ORDER OF THE COMMISSION.
This 7th day of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

ac060701.01

Commissioner Judy Hunt concurs in part and dissents in part.
Commissioner Robert V. Owens, Jr. did not participate in this decision.

DOCKET NO. G-44

COMMISSIONER JUDY HUNT, CONCURRING IN PART AND DISSENTING IN PART: While I fully support the development of natural gas service in eastern North Carolina, I respectfully dissent from that part of the Majority's decision which refuses to reserve $2 million from the award of bond funds to Eastern North Carolina Natural Gas Company (Eastern) in consideration of the notice of intent that was filed by Frontier Energy LLC (Frontier) and admitted in evidence in this docket. I simply cannot subscribe to the rationale set forth by the Majority in support of its decision on that one limited issue, but otherwise fully support the decision in this docket.

By Order entered in Docket No. G-40, Sub 3 on June 29, 2000, the Commission approved Frontier's proposed project to extend natural gas service to Ashe County and the Company's request for funding in the amount of $9.3 million from natural gas bond funds. Like the 14 counties to be served by Eastern in eastern North Carolina, Ashe County does not currently have natural gas service and is therefore an "unserved area" as that term is used in G.S. 62-2(9) and G.S. 62-159 and Commission Rule R6-90. Prior to Frontier's application, no party had ever proposed to provide natural gas service in Ashe County. The Commission has now been notified by Frontier that the negative net present value (NPV) for the Ashe County project has increased by approximately $2 million since the Commission initially awarded the Company $9.3 million for that project and that Frontier intends to request additional bond funds in that amount in 2002, once the Ashe County project has been completed. That being the case, I strongly believe that it is reasonable for the Commission to reserve $2 million of the remaining natural gas bond funds so that Frontier may simply have an opportunity to apply for additional bond funds in that amount. If Frontier can substantiate and carry the burden of proving such a request, then it should be awarded additional bond funds. If

Frontier fails to carry that burden, those funds could then be awarded to Eastern. Timely completion of the Frontier project is extremely important to the residents of Ashe County and that project has in fact been given the Commission's wholehearted imprimatur. There can be no harm in acting in a judicious manner at this point in time in order to ensure, to the maximum extent possible, that the Ashe County project will be completed in the least-cost manner to the consumers it will serve. There is also precedent for granting additional funds to local gas distribution companies (LDCs) in cases where the LDCs have been able to document increases in the negative NPVs of projects funded from natural gas expansion funds. Fairness dictates allowing Frontier that same opportunity in the case of its Ashe County project. The Majority's statement that Frontier, like any other qualified applicant, may apply "[i]f any additional funding for natural gas expansion becomes available in the future from any source," is speculative and of no real consequence or immediate help to Frontier and its future customers in Ashe County.

For all of these reasons, I strongly believe that the most equitable course of action in this case would be for the Commission to approve natural gas bond funds to Eastern in the amount of $147.6 million and reserve a decision on the remaining $2 million of bond funds until Frontier has a reasonable opportunity to apply and make its case for entitlement to those funds. In my view, the Ashe County project is equally important, just as essential to citizens, and squarely entitled to fair consideration for funding through bond funds as the Eastern project covering 14 counties in Eastern North Carolina. I see no harm to anyone in deferring until early next year a ruling on entitlement to $2 million of bond funds in this case, particularly since that amount represents only <u>one percent</u> of the total bond funds available for distribution and since Eastern would still have received an allocation of more than <u>93 percent</u> of the total available bond funds.

/s/ Judy Hunt
Commissioner Judy Hunt

DOCKET NO. G-3, SUB 228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of NUI Corporation, d/b/a	)	RECOMMENDED ORDER
NUI North Carolina Gas, For Approval to	)	DENYING APPLICATION
Establish a Natural Gas Expansion Fund	)	AND REQUIRING REFUNDS

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on November 21, 2000, at 9:30 a.m.

BEFORE: Commissioner William R. Pittman, presiding; Commissioners Ralph A. Hunt and Robert V. Owens, Jr.

APPEARANCES:

For NUI North Carolina Gas:

James H. Jeffries IV, Amos, Jeffries & Robinson, Post Office Box 787, Greensboro, North Carolina 27402

For the Using and Consuming Public:

Antoinette R. Wike, Chief Counsel, Public Staff - N.C. Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY HEARING COMMISSIONERS RALPH A. HUNT AND ROBERT V. OWENS, JR.: On June 14, 2000, NUI Corporation, d/b/a NUI North Carolina Gas (NC Gas), filed a petition pursuant to G.S. 62-158 and Commission Rule R6-82 seeking authority to establish an expansion fund to be used for the extension of natural gas facilities into unserved areas of its franchised territory and to deposit supplier refunds and interest in the amount of $1,922,179.22 into the fund. By order issued on September 12, 2000, the Commission scheduled the matter for hearing, required the prefiling of testimony, and provided for public notice.

A petition to intervene was filed by Carolina Utility Customers Association, Inc. (CUCA), on October 20, 2000, and it was allowed by Commission order issued on October 25, 2000.

The matter came on for hearing as scheduled. NC Gas presented the direct and rebuttal testimony of Richard Wall, the Director of Utility Operations South for NUI Corporation. The Public Staff presented the testimony of James G. Hoard, Assistant Director in the Accounting Division of the Public Staff. There were no public witnesses.

Commissioner Pittman resigned from the Commission effective January 23, 2001, and did not participate in this decision. The remaining members of the panel have decided this matter as Hearing Commissioners.

NATURAL GAS - EXPANSION

Based upon the evidence presented at the hearing and the entire record in this matter, the Hearing Commissioners make the following:

FINDINGS OF FACT

1. NC Gas is a natural gas local distribution company (LDC) authorized to provide natural gas service within its franchised territory in North Carolina, which includes all of Rockingham County and the southeast portion of Stokes County.

2. NC Gas is currently serving the major population centers within its franchised territory, including Madison, Mayodan, Eden, Reidsville, and Wentworth in Rockingham County and Walnut Cove in Stokes County.

3. The areas between these major population centers are generally undeveloped and sparsely populated, with the exception of a few small towns. Stoneville, with a population of approximately 1,100, is the only incorporated town in NC Gas' franchised territory that does not have natural gas service.

4. NC Gas is currently holding in escrow approximately $2 million in supplier refunds and interest which it proposes to deposit into an expansion fund. In its application in this docket, NC Gas identifies Stoneville, the Reidsville Industrial Development Zone (IDZ) and the Eden IDZ as potential expansion fund projects. All three are in Rockingham County. All three are economically infeasible according to net present value (NPV) studies performed by NC Gas.

5. The Stoneville project would involve installing four miles of high pressure six-inch steel main from NC Gas' six-inch pipeline near Mayodan to a district regulator station located near Stoneville and then installing 13.5 miles of low-pressure plastic main throughout the town.

6. The Reidsville IDZ project would involve installing two miles of high-pressure eight-inch steel main to a zone that Reidsville has established on Highway 87 near US Highway 29 south of Reidsville.

7. The Eden IDZ project would involve installing five miles of high-pressure eight-inch steel main to a zone that Eden has established on Harrington Highway (Routes 135 and 770) near Eden.

8. Stoneville is located five miles northeast of Mayodan and six miles southwest of Eden, both of which have natural gas service. The Reidsville and Eden IDZs are both located in close proximity to cities that have natural gas service.

9. Transco, the major interstate natural gas pipeline serving North Carolina, traverses the middle of Rockingham County.

10. Rockingham County has been designated by the North Carolina Department of Commerce as a Tier 3 county for purposes of receiving special economic development incentives from the State.

11. There are several ways to mitigate the negative NPV of extending natural gas facilities that are economically infeasible. These include not only expansion funds and natural gas bond funds, but also more traditional means such as additional revenues from customer gas load, contributions-in-aid-of-construction from customers, and economic development incentives from state and local governments.

12. Factors which the Commission should consider in determining whether to establish an expansion fund pursuant to G.S. 62-158 and Commission Rule R6-82 include the following:

a. the size of the geographic area without service;
b. the size of the unserved area relative to the amount of natural gas infrastructure already existing within the county involved;
c. the location of population centers within the county and their proximity to natural gas infrastructure;
d. the presence or lack of economic development in the county;
e. in some cases, practical engineering and right-of-way aspects of installing natural gas facilities; and
f. whether traditional economic tests and policies and other sources of funding should take precedence over use of expansion funds.

13. A one-time refund of the supplier refunds and interest that NC Gas is holding in escrow could reduce bills of residential customers by as much as forty dollars.

DISCUSSION OF EVIDENCE AND CONCLUSIONS

This proceeding presents difficult issues of interpretation as to the scope of G.S. 62-2(9) and G.S. 62-158. By G.S. 62-2(9), the General Assembly declares it the policy of the State to authorize natural gas expansion funds to be administered by the Utilities Commission in order to facilitate the extension of natural gas service to unserved areas in order to promote the public welfare throughout the State. G.S. 62-158 provides that the Commission may order an LDC to create such an expansion fund to be used to construct natural gas facilities in areas of the LDC's franchised territory that otherwise would not be feasible for the company to construct. The statute lists refunds to LDCs from suppliers of natural gas and transportation services as a source of funding for such expansion funds.

In ruling upon the constitutionality of these statutes, the North Carolina Supreme Court held that the Commission has some level of discretion in deciding whether to create an expansion fund for a particular LDC. The Commission does not have discretion with regard to whether the policy embodied in G.S. 62-158 is wise or unwise; however, the Supreme Court held that the Commission does have discretion "to evaluate pertinent factors in a manner consistent with the legislative intent; [and] if, after doing so, the Commission concluded that the creation of an expansion fund would not be in the public interest, it would presumably decline to order the creation of such a fund". *State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc.*, 336 N.C. 657, 666, 446 S.E.2d 332 (1994); also, *State ex rel. Utilities Commission v. Piedmont Nat. Gas Co.*, 346 N.C. 558, 584 (1997). The Supreme Court held that Commission Rule R6-82(d) reflects a "proper view" of the Commission's discretion in deciding whether to create an expansion fund for an LDC. Commission Rule R6-82(d) provides in part:

> In determining the establishment of a fund and the sources and magnitude of the initial funding, the Commission will consider the LDC's showing that expanding to serve unserved areas is economically infeasible and such other factors as the Commission deems reasonable and consistent with the intent of G.S. 62-158 and G.S. 62-2(9). Before ordering the establishment of a fund, the Commission must find that it is in the public interest to do so. [Emphasis added.]

In this recommended order, the Hearing Commissioners will elaborate upon what other factors have been considered and why creation of an expansion fund for NC Gas would not be in the public interest.

A preliminary consideration is whether there are "unserved areas" within the meaning of G.S. 62-158 in the LDC's franchised territory. The Commission wrestled with the meaning of "unserved areas" when it adopted Commission Rules to implement G.S. 62-158 in 1992. In its Order Adopting Commission Rules R6-81 to R6-88, dated April 9, 1992, in Docket No. G-100, Sub 57, the Commission recognized the difficulty in defining the term. The Commission defined the term as "Counties, cities or towns of which a high percentage is unserved." However, in adopting this definition, the Commission stated that G.S. 62-158 was not intended for purely infill projects and that it was "better to maintain flexibility at this stage of implementing G.S. 62-158." See 82 N.C.U.C. 11, 12-13 (1992). A full reading of this order indicates that the Commission adopted a broad definition of "unserved areas" in order to keep its options open, but that the Commission intended to refine the concept in future cases and to judge individual projects on the basis of whether they come within the intent of G.S. 62-158. Sometime later, in its April 4, 1996 Order Establishing Expansion Fund and Approving Initial Funding on Contingent Basis in Docket No. G-9, Sub 328, the Commission had to decide whether to create an expansion fund for Piedmont Natural Gas Company, Inc. The Commission noted that Piedmont had some level of service in all of its counties, and the Commission therefore established Piedmont's fund on a contingent basis "so that the issue of whether any particular project qualifies for use of the fund as an 'unserved area' can be decided in the future as individual applications are filed." See 86 N.C.U.C. 350, 355 (1996). Once again, the Commission signaled its intention to decide on a case-by-case basis whether potential expansion fund projects are for the kind of "unserved areas" that the General Assembly intended.[1] Turning to the present docket, it is questionable whether two of the three potential expansion fund projects identified by NC Gas involve "unserved areas" even under the broad definition adopted by the Commission. The IDZs are neither counties, cities nor towns of which a high percentage is unserved. They are essentially zoning designations of areas slated for industrial development within a county that already enjoys a high level of natural gas service. The third potential expansion fund project is for an unserved town that is economically infeasible to serve, but that is not the end of the inquiry. Other factors remain to be considered.

As just noted, under Commission Rule R6-82(d) and in the exercise of discretion as defined and approved by the Supreme Court, the Hearing Commissioners must consider other factors relevant to G.S. 62-158 in order to decide whether it is in the public interest to create an expansion fund for NC Gas. In considering such factors, we must remember the context in which G.S. 62-158 was

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[1] The Commission has in fact only used Piedmont's expansion fund to help build facilities in counties that were franchised to Piedmont after April 1996 and had no natural gas service at all.

enacted. In 1991, there were 38 counties without any natural gas service at all and others with very little service. Generally, these were counties with relatively low population densities. The Public Staff testified, and the Hearing Commissioners agree, that the General Assembly intended for expansion funds to be used to facilitate extension of service into large geographic areas that are economically disadvantaged, at least in part, due to lack of natural gas service. Consistent with that focus, the Hearing Commissioners believe that appropriate factors to consider in determining whether to establish an expansion fund pursuant to G.S. 62-158 and Commission Rule R6-82 include the size of the geographic area without service, the size of the area relative to the amount of natural gas infrastructure already existing within the county involved, the location of population centers within the county and their proximity to natural gas infrastructure, the presence or lack of economic development in the county, practical engineering and right-of-way aspects of installing natural gas facilities in some cases, and whether traditional economic tests and policies and other sources of funding should take precedence over use of expansion funds.

The record indicates that the areas that would be served by the potential expansion fund projects of NC Gas are relatively small; each potential project involves a transmission line to a single town or IDZ and none of them requires more than five miles of transmission facilities. Further, these are small areas within a county that has significant natural gas infrastructure already. Economic infeasibility is often a function of distance. With traditional funding methods, it is often economically infeasible to construct natural gas facilities over long distances to reach unserved areas. Large geographic areas can thereby be left without the natural gas infrastructure needed to attract industry and create jobs. People living in such areas might have to commute long distances to areas where natural gas service is available and economic prospects more promising. These are the concerns that prompted enactment of G. S. 62-158, but this is simply not the situation in Rockingham County. Commuting distances from areas without natural gas service to areas with natural gas service are relatively short in Rockingham County. Compared to other LDCs and other counties, there is significant natural gas infrastructure available to promote economic development in Rockingham County. The major population centers already have natural gas service. Rockingham County has been designated by the North Carolina Department of Commerce as a Tier 3 county for purposes of receiving special economic development incentives; this is on a scale of five with Tier 1 being the most disadvantaged and Tier 5, the least. It is undoubtedly true that any unserved town or area would prefer to have natural gas service available, but small unserved areas exist throughout the State, even in the most populous counties where natural gas service is extensive and economic development flourishing. The Hearing Commissioners do not believe that the General Assembly intended for the special funding mechanism authorized by G.S. 62-158 to be used to extend service to every town and every potential industrial site in the State regardless of the natural gas infrastructure and economic development already existing in the county involved. Otherwise, the disparity between the economically disadvantaged counties where natural gas service is only now being made available through expansion funds and natural gas bond funds and the relatively industrialized counties would become even greater. The reality is that Rockingham County already has more natural gas service and less need for special expansion funding than many other counties. When other counties reach the level of natural gas infrastructure enjoyed in NC Gas' territory, they will no longer need special funding either. Without special funding for natural gas expansion, service will be extended where it is economically feasible based on revenues, contributions-in-aid-of-construction, and state and local economic development incentives. The Hearing Commissioners do not believe that the General Assembly intended for G.S. 62-158 to supplant these traditional methods of extending service once a certain level of natural gas infrastructure is in place. That level of infrastructure already exists in NC Gas' franchised territory. It is therefore unlikely that NC Gas will ever qualify for an expansion fund.

Finally, the Hearing Commissioners cannot ignore the high level of natural gas prices at the present time. A refund of the $2 million held in escrow by NC Gas will help to mitigate high customer bills during the current winter, and the return of supplier refunds in the future will help to make natural gas more attractive as a fuel of choice. Natural gas can only serve to promote economic development if natural gas prices are competitive with other fuels. For NC Gas today, reducing customers' gas costs is more consistent with the public interest than applying supplier refunds toward further natural gas infrastructure in Rockingham County.

The Hearing Commissioners therefore conclude that the petition of NC Gas for establishment of an expansion fund and authority to deposit supplier refunds and interest held in escrow into that fund should be denied. The Hearing Commissioners further conclude that the supplier refunds and interest held by NC Gas should be allocated among rate classes according to the current fixed gas cost apportionment percentages and refunded to ratepayers based on usage during the past 12 months. Refunds should be made by a bill credit, except in the case of large customers who have left the system during the past 12 months, in which case refunds should be made by check if the customers can be located.

IT IS, THEREFORE, ORDERED as follows:

1. That the petition of NC Gas for authority to establish an expansion fund pursuant to G.S. 62-158 and to deposit supplier refunds and interest into such fund is denied;

2. That in the next possible billing cycle following the effective date of the decision herein NC Gas shall, in the manner set forth in this order, refund to its ratepayers the supplier refunds and interest that it is now holding in escrow for possible deposit into an expansion fund; and

3. That the refunds shall be accompanied by a notice of this decision in a form to be approved by the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of February, 2001

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg022801.01

Commissioner Pittman resigned from the Commission effective January 23, 2001, and did not participate in this decision.

DOCKET NO. G-3, SUB 228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of NUI Corporation, d/b/a	)	FINAL ORDER OVERRULING
NUI North Carolina Gas, For Approval to	)	EXCEPTIONS AND AFFIRMING
Establish a Natural Gas Expansion Fund	)	RECOMMENDED ORDER

BY THE COMMISSION: This docket involves a request by NUI Corporation, d/b/a NUI North Carolina Gas (NC Gas), to create an expansion fund pursuant to G.S. 62-158. A Recommended Order Denying Application and Requiring Refunds was issued in this docket by two Hearing Commissioners on February 28, 2001. NC Gas filed Exceptions on March 15, 2001, and oral argument was scheduled by Order of March 21, 2001. Oral argument was held before the Commission as scheduled on April 2, 2001, at which NC Gas and the Public Staff presented argument.

After carefully considering the arguments and the complete record in this docket, the Commission finds good cause to overrule the Exceptions filed by NC Gas and to affirm and adopt the Recommended Order as the final order of the Commission in this docket.

This was a difficult decision for the Hearing Commissioners, and it was a difficult decision for the Commission as well. However, in the end, we believe that it is the right decision. The Commission believes that the expansion fund statute was enacted to address a discrete problem. In 1991, there were 38 counties in North Carolina without any natural gas service and others with very little natural gas infrastructure. The absence of natural gas service in large areas of the State was affecting economic development patterns across the State as a whole. This is the problem that prompted the expansion fund statute, but this problem did not exist in NC Gas' territory then and it does not exist in NC Gas' territory today. NC Gas has done an excellent job of establishing natural gas infrastructure for its customers, and NC Gas is to be commended for the level of service that exists in its territory. Given this level of service, the public interest favors returning the supplier refunds held by NC Gas to the ratepayers who contributed them and leaving future expansion of natural gas service in NC Gas' territory to traditional financing methods. These traditional methods have supported establishment of natural gas service in the five major population centers of Rockingham County, and the Commission sincerely hopes that means can be found soon to extend such service to Stoneville as well.

IT IS, THEREFORE, ORDERED, that the Exceptions filed by NC Gas herein on March 15, 2001, should be, and the same hereby are, overruled and the Recommended Order of February 28, 2001, adopted as the final order of the Commission.

ISSUED BY ORDER OF THE COMMISSION
This is the 12th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rg040901.04

Commissioner Conder dissents.

NATURAL GAS - EXPANSION

DOCKET NO. G-3, SUB 228

COMMISSIONER CONDER DISSENTING:

I respectfully dissent from the majority of my colleagues on the NC Gas case in Docket No. G-3, Sub 228. The General Assembly of North Carolina passed House Bill 1039 in the 1991 session by adding G.S. 62-2 and G.S. 62-158 to facilitate the construction of natural gas service to unserved areas in order to promote the public welfare throughout the state and to that end to authorize creation of expansion funds for natural gas local distribution companies to be administered by the North Carolina Utilities Commission. I was a member of the General Assembly at the time and recall the intent was to serve unserved areas of North Carolina that otherwise would not be feasible and the 4-mile line to the Town of Stoneville certainly meets that criteria.

NC Gas has requested establishing a natural gas expansion fund as plainly set forth in the statute and as has been approved for the other local distribution companies in North Carolina. Rockingham County has experienced high unemployment due to NAFTA and other competitive pressures in the textile industry. This proposed line to Stoneville would certainly enhance the public welfare and the confidence of the citizens residing in that area and provide an opportunity for economic growth.

Furthermore, the citizens of North Carolina approved a $200,000,000 bond issue to furnish natural gas to unserved areas of North Carolina. This sends a strong, bold message from our citizens that they want to assist and help communities such as Stoneville in Rockingham County. The alternative is to give NC Gas residential customers a $40.00 one-time refund. It is my opinion that existing natural gas customers would forego their refund to help unserved customers enjoy natural gas as they have in other areas of Rockingham County.

In summary, let me reiterate my personal knowledge of the intent of the legislation creating the expansion fund to be funded by supplier refunds, expansion surcharges by the local distribution companies and other sources approved by the Commission. The intent of this legislation and of the $200,000,000 bond issue strongly supports NC Gas' request for the creation of an expansion fund and the use of supplier refunds to construct this project.

\s\ J. Richard Conder

COMMISSIONER J. RICHARD CONDER

DOCKET NO. G-3, SUB 228

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Application of NUI Corporation d/b/a NUI North	) ORDER ALLOWING MOTION
Carolina Gas for Approval to Establish a Natural	) FOR STAY OF REFUND
Gas Expansion Fund	)

BY THE COMMISSION: On February 28, 2001, a Recommended Order was issued in this docket denying the application of NUI Corporation, d/b/a NUI North Carolina Gas (NC Gas), for creation of an expansion fund and requiring NC Gas to refund supplier refunds and interest held in escrow beginning with the next possible billing cycle. The Recommended Order was affirmed by Final Order of the Commission dated April 12, 2001.

On April 27, 2001, NC Gas filed a Motion for Stay of Refund Obligation Pending Appeal. NC Gas asserts that it intends to appeal the Commission's decision herein and that the refund obligation should be stayed pending resolution of the appeal in order to preserve the supplier refunds and interest for possible use in an expansion fund.

The Commission finds good cause to stay the refund ordered herein. The refund obligation shall become effective again if no timely appeal is taken in this docket or upon a final decision of the appellate courts affirming the Commission.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 30th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb043001.02

DOCKET NO. G-21, SUB 395

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by North Carolina Natural Gas Corporation for Approval of the Use of Expansion Funds for an Expansion Project into an Unserved Area of Columbus County	)	ORDER APPROVING EXPANSION PROJECT FOR FUNDING FROM EXPANSION FUND

HEARD: Thursday, January 4, 2001, at 9:30 a.m., and Wednesday, February 7, 2001, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sam J. Ervin, IV, presiding; Chair Jo Anne Sanford, and Commissioners Ralph A. Hunt, Judy Hunt, J. Richard Conder, Robert V. Owens, Jr., and Lorinzo L. Joyner

APPEARANCES:

For North Carolina Natural Gas Corporation:

Edward S. Finley, Jr., Hunton & Williams, Post Office Box 109, Raleigh, North Carolina 27602

Len Anthony, Associate General Counsel and Bentina D. Chisolm, Associate General Counsel, CP&L Service Company, LLC, Post Office Box 1551, Raleigh, North Carolina 27602

For the Using and Consuming Public:

Paul L. Lassiter, Staff Attorney, Public Staff – North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: On August 29, 2000, North Carolina Natural Gas Corporation (NCNG) filed a petition pursuant to G.S. 62-2(9) and 62-158 and Commission Rule R6-84 for approval of partial funding from NCNG's expansion fund for an expansion project that would provide additional natural gas service in Columbus County.

By order issued on September 26, 2000, the Commission scheduled the matter for public hearing, required public notice and established a procedural schedule. On December 13, 2000, the Public Staff and NCNG filed a Joint Motion asking that the schedule be held in abeyance because NCNG planned to amend its application. By order issued on December 14, 2000, the Commission held the procedural schedule in abeyance except for the public hearing scheduled for January 4, 2001, which was held as scheduled. On January 8, 2001, NCNG and the Public Staff filed a Motion to

Reinstate Hearing Schedule. By order issued January 12, 2001, the Commission rescheduled the hearing for testimony from the parties for February 7, 2001.

On October 20, 2000, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene which was granted by order dated October 25, 2000.

At the public hearings on January 4, 2001, the following persons appeared and testified as public witnesses in support of the petition: Dempsey Herring, Columbus County Manager; Stephen Lynch of the Tabor City Economic Development Commission; Hazen Blodgett, Whiteville City Manager; and Carlton Williamson, attorney for Whiteville and member of the Columbus County Committee of 100.

NCNG prefiled the testimony and exhibits of the following witnesses: Terrence D. Davis, Senior Vice President – Operations for NCNG; George M. Baldwin, Vice President – Marketing for NCNG; and Robert P. Evans, Project Business Analyst – Pricing and Rate Applications in the Treasury Department of Carolina Power and Light Company.

The Public Staff prefiled the joint affidavit of James G. Hoard, Assistant Director of the Accounting Division of the Public Staff; Jan A. Larsen, Utility Engineer of the Natural Gas Division of the Public Staff; and Calvin C. Craig, III, Financial Analyst of the Economic Research Division of the Public Staff.

The hearing was held as scheduled. CUCA did not appear at the hearing. The prefiled testimony, exhibits and affidavit were stipulated into the record. Without objection, resolutions from Columbus County, Whiteville and Tabor City were submitted as late-filed exhibits.

Based on the petition, the testimony and exhibits and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. NCNG, a Delaware corporation with its principal office in Raleigh, North Carolina, operates a natural gas local distribution system consisting of natural gas transmission pipeline, distribution mains and other facilities for furnishing natural gas service to the public within its franchised service territory.

2. NCNG's franchised service territory covers counties in south central and eastern North Carolina including Columbus County.

3. NCNG is properly before the Commission on its petition for approval of partial funding from NCNG's expansion fund for an expansion project to provide additional natural gas service in Columbus County.

4. There is currently only limited natural gas service in Columbus County. The records of the Commission reveal that NCNG built a 17-mile, six-inch transmission line from Bladen County into Columbus County to the Southeastern Industrial Park west of Whiteville in 1997. Records also

reveal that NCNG has a 12-inch transmission line that runs across the northeastern tip of the county. Neither line serves a major population center of the county. There are fewer than 10 natural gas customers in the county.

5. Columbus County has 945 square miles and a population of about 52,000 people. The two major population centers of the county are Whiteville and Tabor City, neither of which has natural gas service now. Columbus County is a Tier 1 county for purposes of receiving special economic development incentives. The County has experienced significant job losses in recent years. The unemployment rate is near 10 percent.

6. The proposed expansion fund project includes a six-inch transmission pipeline beginning in Tabor City at the Tabor City Industrial Park on Highway 904; proceeding southeast on Highway 904; turning east onto city streets, East 8th Street and south on Stake Street; turning north on U.S. Highway 701 Business/East 5th Street; proceeding north on U.S. Highway 701; and ending approximately 1.4 miles north of S.R. 1332. At this point, the expansion project, which is called Phase 1, will join Phase 2 facilities, which will be constructed without expansion funds. Phase 2 will run north to a city gate for Whiteville and then west and north to connect to the existing line serving the Southeastern Industrial Park.

7. Leaders from Columbus County, Whiteville and Tabor City believe that there is a strong need for the proposed natural gas service and that the lack of natural gas service has hampered industrial and economic development in Columbus County. Due to existing infrastructure, natural resources and a favorable business climate, the unserved area covered by NCNG's proposed expansion project has good industrial and economic growth potential.

8. The proposed project will bring natural gas service to portions of Columbus County which currently have no natural gas service. Together with Phase 2, it will bring natural gas service to Tabor City and to a city gate for Whiteville. The project will provide natural gas service to an unserved area as that term is defined in G.S. 62-2(9) and 62-158 and Commission Rule R6-81.

9. There is a reasonable prospect that the construction and operation of natural gas facilities in the unserved area covered by NCNG's proposed expansion project in this docket will assist in industrial and economic growth in the area. Highway 701 is heavily traveled and serves as an economic development corridor for the county.

10. The pipeline route proposed is the most direct, cost-effective route to serve the area covered by the expansion project and will also maximize potential attachments of gas customers and utilize existing corridors to facilitate construction. NCNG's design and location of the proposed transmission pipeline and distribution mains for this project are appropriate.

11. To encourage the approval of this expansion project, Columbus County, Whiteville and Tabor City have submitted resolutions to the Commission committing to provide financial assistance to the project in the form of payments to NCNG's expansion fund in amounts equal to

75 percent of the ad valorem tax revenues collected for the expansion project for five years (with a $473 annual cap for Whiteville). The willingness of the local governments in the area to provide financial assistance in order to facilitate the expansion project is viewed as a positive factor by the Commission.

12. The local government assistance payments are reasonable and appropriate sources of funds to be deposited into NCNG's expansion fund as received. These local government assistance payments will be direct contributions to NCNG's expansion fund and will, to the extent received, be designated as reimbursement for a portion of the funds expended on the proposed project.

13. The projected initial annual volumes from potential customers now located in the area to be served, margins from which are included in the net present value (NPV) calculation, are expected to be 22,100 dekatherms. The nature and amount of natural gas usage by new industrial and large commercial facilities that may locate in the area covered by the expansion project, but which are not presently in existence, cannot be quantified to the degree of certainty appropriate for inclusion in the NPV calculation. To the extent industrial and large commercial growth occurs, NCNG's system will benefit.

14. The total cost of the proposed expansion fund project is estimated to be $3,792,783.

15. The NPV for the proposed expansion fund project is a negative $3,400,000. NCNG's shareholder investment in the project is estimated to be $392,783, and such amount is reasonably supported by margins estimated to be received on gas sales and transportation.

16. NCNG should have sufficient monies in its expansion fund as needed for the acquisition of the rights-of-way and the construction of the proposed project.

17. The Columbus County expansion fund project proposed by NCNG is in accordance with G.S. 62-2(9) and 62-158 and should be approved for funding from NCNG's expansion fund.

18. NCNG must connect the proposed expansion fund project to the Phase 2 facilities and gas must be flowing through Columbus County from the Southeastern Industrial Park into Tabor City before NCNG will receive its final distribution of expansion funds.

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

The evidence for these findings of fact is contained primarily in the petition, the Commission's files and records in this proceeding, and the testimony of NCNG witness Davis. These findings are essentially informational, procedural or jurisdictional in nature and are uncontradicted by any of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 4-10

The evidence for these findings is found primarily in NCNG's petition, the testimony and exhibits of NCNG's witnesses Davis and Baldwin, the testimony of public witnesses, and the records of the Commission.

NATURAL GAS - EXPANSION

The records of the Commission reveal that only limited natural gas facilities exist in Columbus County now. There is a 17-mile, six-inch transmission line from Bladen County to the Southeastern Industrial Park west of Whiteville and a 12-inch transmission line that runs across the northeastern tip of the county. Neither serves a major population center. Columbus County has 945 square miles and a population of about 52,000 people. The county has been designated by the North Carolina Department of Commerce as a Tier 1 county for purposes of receiving special economic development incentives; this is on a scale of five with Tier 1 being the most disadvantaged. The public witnesses indicated that Columbus County has experienced significant job losses in recent years and that the unemployment rate is near 10 percent.

The public witnesses testified concerning the infrastructure available in Columbus County to support economic development. The public witnesses discussed in detail the importance of natural gas to economic development. Public witnesses testified concerning lost opportunities in their area because of the lack of natural gas. Davis Exhibit 3 indicates that it takes months or perhaps one year to plan and construct a natural gas extension project. Various public witnesses concluded that many industries are not willing to wait and that opportunities are being missed. Witnesses expressed their belief that this project is an excellent opportunity for positively impacting economic development. In deciding on a proposed project to provide additional natural gas service to Columbus County, NCNG placed weight on the potential for economic development in the area and the population base that could benefit from natural gas service, taking into consideration terrain and distance to maximize the project's feasibility. NCNG's application indicates that an additional benefit is that NCNG will be able to extend the project to include distribution systems in Whiteville and Tabor City.

NCNG witness Davis provided a detailed description of the physical facilities, operating parameters, route selection, proposed rights-of-way arrangements and the location of distribution systems necessary for the revenues included in the NPV study. The project proposed by NCNG includes a 6-inch transmission pipeline beginning in Tabor City at the Tabor City Industrial Park on Highway 904; thence proceeding southeast on Highway 904, turning east onto city streets, East 8th Street and south on Stake Street; turning north on U.S. Highway 701 Business/East 5th Street; proceeding north on U.S. Highway 701; and ending approximately 1.4 miles north of S.R. 1332. NCNG witness Davis set forth the geographic location of the proposed facilities in Davis Exhibit 1. Witness Davis testified that the route selected was the most cost-effective choice.

Public Staff witnesses testified that the project as proposed by NCNG is appropriate based upon the Public Staff's on-site field investigation.

The Commission concludes that the proposed expansion fund project will serve an unserved area as that term is defined in G.S. 62-2(9) and 62-158 and Commission Rule R6-81, that the facilities as proposed are reasonably sized and designed, and that the proposed route is appropriate.

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

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Evans; the testimony of public witnesses Herring, Lynch, Blodgett, and Williamson; and the resolutions of certain local governments supporting the project which were filed with the Commission.

Pursuant to Commission Rule R6-84(b) and (d), one factor that the Commission may consider in deciding whether to approve funding from an expansion fund for a particular project is the extent of contributions from local governments. Columbus County, Whiteville and Tabor City passed resolutions expressing their support for the proposed project and authorizing the provision of financial assistance to facilitate the project and its approval by the Commission. In general, they agree that they will deposit with the State Treasurer for NCNG's expansion fund 75% of the ad valorem tax revenues collected for the expansion project for five years (with a $473 annual cap for Whiteville). These local governments recognized that there is a great demand for the extension of natural gas facilities throughout eastern North Carolina, but that funds available to pay for such extensions are limited. Local government assistance payments are viewed as a positive factor by the Commission.

The Commission believes that local government assistance payments in the form set forth in the resolutions are appropriate sources of funds for NCNG's expansion fund and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is contained in the testimony and exhibits of NCNG witnesses Davis and Baldwin and the testimony of the Public Staff witnesses.

The Public Staff witnesses testified that their investigation supports NCNG's customer projections. NCNG witness Baldwin testified concerning NCNG's marketing efforts in Columbus County. Initially, NCNG obtained information from the directors of the economic development commissions in the County and, as it proceeded in its efforts, it relied closely on relationships with other persons involved in economic development, including civic leaders. NCNG conducted marketing studies to locate potential customers along potential natural gas pipeline routes. Such information was used as part of the route selection. Witness Baldwin set forth in his exhibits the industries which were located in Columbus County and interested in natural gas and the characteristics of their fuel usage. Most of the individual facilities utilize propane and No. 2 fuel oil. NCNG included in its proposed expansion project commercial/industrial customers located along the project route. Witness Baldwin provided information concerning the types of commercial customers included and their consumption characteristics. He testified that in his opinion, NCNG had included all the potential customers currently located along the project route which would positively impact the NPV calculation for this project. Baldwin Exhibit 2 set forth the projected annual volumes from potential customers now located in the area to be served by this project.

NCNG did not include as a part of its NPV calculation any projected margins from industrial and large commercial facilities that may subsequently locate in the area to be covered by the expansion project. Commission Rule R6-86 provides that if an expansion project is successful and economic development does occur, adding additional gas loads to the project, the utility may buy back, with Commission approval, the portion of the project that has become economically feasible. This rule recognizes that future growth in the previously unserved area, which is the goal of expansion projects, cannot be quantified at the time the project is approved and should not be included in the NPV study. The rule enables expansion fund monies to be rolled over for use on other projects, should expansion projects become feasible through economic growth and the addition of gas load. The Commission concludes that NCNG and the Public Staff have appropriately dealt with the prospect for growth along the pipeline route. The Commission further concludes that, based upon the evidence presented to it, the projected annual volumes from potential customers are reasonable.

NCNG witness Evans testified that once annual volumes for potential customers were projected, margins were determined based upon customer survey and/or NCNG's experience with the types of customers included in the project and their alternative fuel capabilities. The Commission believes that this is a reasonable method for determining margins for the purposes of the NPV calculation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding of fact is contained primarily in the testimony of NCNG witness Davis.

NCNG witness Davis testified that the total estimated cost of the project as proposed by NCNG in its petition was $3,792,783. Davis Exhibit 2 set forth a detailed breakdown of the plant costs for both transmission and distribution plant additions. NCNG witness Davis testified that NCNG had reviewed the terrain of the proposed route from both the air and ground to determine the extent of wetland crossings and other impediments which could affect cost. NCNG then used unit costs from recent gas construction projects in its service territory and was assisted in the estimation process by a contractor familiar with pipelines of this nature.

The Commission concludes that the total cost estimate for the project is reasonable and is appropriate for use in the Company's NPV calculation based upon the evidence presented to the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 15 AND 16

The evidence for these findings of fact is contained in the petition of NCNG and in the testimony and exhibits of NCNG witnesses Davis and Evans and the testimony of Public Staff witnesses Hoard, Larsen and Craig.

NCNG witness Evans determined that the NPV for the proposed project was a negative $3,400,000. The Public Staff's NPV calculation differs from that of NCNG in limited areas that did not reduce the level of the negative NPV. For the reasons set forth in this Order and based upon the evidence as a whole, the Commission concludes that the Company's calculation of the negative NPV of the proposed project is fair and reasonable.

As of June 30, 2000, the balance held by the State Treasurer for NCNG's expansion fund was approximately $3,487,054. NCNG was holding additional funds totaling approximately $182,302 for possible inclusion in its expansion fund. It appears to the Commission that expansion fund monies will be available as they are needed for the negative NPV of the project the Commission is approving in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 AND 18

The evidence for these findings of fact is contained in the testimony of all the witnesses taken together and their exhibits and workpapers filed with the Commission and received into evidence.

For the reasons set forth herein, the Commission concludes that the proposed expansion fund project is in accordance with the General Statutes and Commission Rules and that funding from NCNG's expansion fund in an amount up to the negative NPV for the project of $3,400,000 should be approved. The Public Staff recommended that NCNG be required to connect the proposed expansion project, which is called Phase 1, to Phase 2 facilities, so that gas supply will indeed flow to Phase 1 before NCNG receives its final distribution of expansion funds. NCNG agreed to this requirement, and the Commission imposes this requirement.

IT IS THEREFORE, ORDERED as follows:

1. That NCNG's proposed expansion fund project to extend natural gas service in Columbus County is hereby approved for funding from NCNG's expansion fund in the amount of $3,400,000, the negative NPV of the project;

2. That disbursement of up to $3,400,000 for this project from NCNG's expansion fund in accordance with applicable Commission Rules and this Order is hereby authorized;

3. That NCNG shall file reports as required by Commission Rules and shall request progress payments, for reimbursement for actual amounts paid by NCNG, pursuant to the provisions of Commission Rule R6-85(b) and such requests shall be handled as provided by that Rule and this Order;

4. That the local government assistance payments authorized in resolutions adopted by Columbus County, Whiteville and Tabor City are hereby approved as a reasonable source of funding for NCNG's expansion fund; and

5. That NCNG shall connect the proposed expansion project, which is called Phase 1, to Phase 2 facilities and gas shall be flowing through Columbus County into Tabor City before NCNG shall receive its final distribution of expansion funds.

ISSUED BY ORDER OF THE COMMISSION.
This the _22nd_ day of _March_, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

rg032201.05

DOCKET NO. G-3, SUB 232

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of NUI Corporation for Approval	)	RECOMMENDED ORDER
of Merger Between VGC Acquisition, Inc.	)	APPROVING MERGER
and Virginia Gas Company	)	

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on December 12, 2000 and January 3, 2001.

BEFORE: Commissioner William R. Pittman, Presiding; Commissioner Judy Hunt, and Commissioner Robert V. Owens, Jr.

APPEARANCES:

For NUI North Carolina Gas:

James H. Jeffries IV, Amos, Jeffries & Robinson, L.L.P., Post Office Box 787, Greensboro, North Carolina 27402

For Carolina Utility Customers Association, Inc.:

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

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

For the Using and Consuming Public:

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

BY HEARING COMMISSIONERS JUDY HUNT AND ROBERT V. OWENS, JR.: On September 15, 2000, NUI Corporation, d/b/a NUI North Carolina Gas (NUI North Carolina Gas, NUI NC Gas, or the Company), filed a petition pursuant to G.S. 62-111(a) for approval of a proposed merger between VGC Acquisition, Inc., a wholly-owned unregulated subsidiary of NUI Corporation (NUI), and Virginia Gas Company. In its application, NUI North Carolina Gas also sought a determination by the Commission that NUI Corporation's issuance of shares in conjunction with the proposed merger was not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

On October 17, 2000, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines, and Requiring Public Notice. This Order established an original hearing date of December 12, 2000, set prefiled testimony dates, and required NUI North Carolina Gas to give notice to its customers of the hearing on this matter. Pursuant to the Commission's November 27, 2000 Order Rescheduling Hearing and Prefiling, the hearing of this matter was continued until January 3, 2001, except for public witness testimony.

On October 20, 2000, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene in this proceeding, and the Petition was subsequently granted by the Commission on October 25, 2000.

The direct testimony of Company witness A. Mark Abramovic was filed on October 27, 2000. The direct testimony of Company witness Douglas R. Bohi, Ph.D. was filed on November 27, 2000, as was the supplemental direct testimony of A. Mark Abramovic. Mr. Abramovic testified to the reasons justifying the proposed merger and provided the company's cost-benefit analyses of the proposed merger. Dr. Bohi testified as to the market power effects of the proposed merger.

A hearing for public witness testimony was held on December 12, 2000, but no public witnesses appeared.

The direct testimony and exhibit of CUCA witness Kevin W. O'Donnell was filed on December 21, 2000.

Company witness Abramovic prefiled rebuttal testimony on December 28, 2000, in order to address issues raised in Mr. O'Donnell's direct testimony. No other party filed testimony.

On December 29, 2000, the Company gave notice of its intent to substitute Ms. Patricia L. Helfer, Corporate Controller for NUI Corporation, in place of Mr. Abramovic and further indicated Ms. Helfer's intent to adopt Mr. Abramovic's prefiled direct, supplemental and rebuttal testimony.

On January 3, 2001, the Company and the Public Staff filed a Stipulation in which they reached agreement and resolved all issues in the case as between the Company and the Public Staff. The Stipulation set forth certain ratepayer protection provisions agreed to by the Company and the Public Staff.

On January 3, 2001, the matter came on for hearing as scheduled in Raleigh. No public witnesses appeared. The prefiled testimony and exhibits of the following witnesses were received into evidence and/or admitted into the record: Patricia L. Helfer[1] and Douglas R. Bohi, Ph.D, for the Company and Kevin O'Donnell for CUCA.

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[1] In light of Ms. Helfer's adoption of Mr. Abramovic's prefiled testimony and exhibits, and for ease of reference, Mr. Abramovic's prefiled direct, supplemental and rebuttal testimony and exhibits are hereinafter referred to as the direct, supplemental and rebuttal testimony and exhibits of Ms. Helfer.

Commissioner Pittman resigned from the Commission effective January 23, 2001, and did not participate in this decision. The remaining members of the panel have decided this matter as Hearing Commissioners.

Based on the testimony and exhibits received into evidence and the record as a whole, the Hearing Commissioners make the following:

FINDINGS OF FACT

1. NUI North Carolina Gas is an operating division of NUI Corporation, which is a corporation organized under the laws of the state of New Jersey and duly registered to do business in North Carolina.

2. NUI North Carolina Gas is engaged in the business of transporting, distributing, and selling natural gas in a franchised area which consists of all of Rockingham County and part of Stokes County in the northern Piedmont region of North Carolina.

3. NUI North Carolina Gas is a public utility as defined by G.S. 62-3(23) and is subject to the jurisdiction of this Commission and lawfully before this Commission upon its application for approval of a merger between its wholly owned and unregulated subsidiary, VGC Acquisition, Inc., and Virginia Gas Company pursuant to G.S. 62-111(a).

4. NUI North Carolina Gas' testimony, exhibits, affidavits of publication and published hearing notices are in compliance with the provisions of the North Carolina General Statutes and the Rules and Regulations of this Commission.

5. NUI Corporation seeks authority, pursuant to G.S. 62-111(a), for its wholly owned subsidiary, VGC Acquisition, Inc., to merge with Virginia Gas Company. The effect of this proposed merger would be the indirect acquisition of Virginia Gas Company by NUI Corporation. NUI North Carolina Gas also seeks a determination by the Commission that NUI Corporation's issuance of shares in conjunction with the proposed share exchange is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

6. In order for NUI North Carolina Gas to obtain Commission approval of its proposed merger between VGC Acquisition, Inc. and Virginia Gas Company, NUI North Carolina Gas must demonstrate that the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company is justified by the public convenience and necessity.

7. NUI Corporation is a multistate public utility with regulated natural gas distribution operations in the states of New Jersey, Maryland, Pennsylvania, New York, Florida and North Carolina. In addition to these regulated distribution operations, NUI Corporation also operates a number of unregulated businesses on a multi-state basis including those engaged in energy brokering, sales outsourcing, business and environmental services.

8. Virginia Gas Company is a Delaware Corporation engaged in a number of energy related businesses located wholly within the State of Virginia including, through subsidiaries regulated by the Virginia Corporation Commission and the Federal Energy Regulatory Commission, natural gas transmission, distribution and storage services. Virginia Gas Company's distribution and transmission businesses are wholly intrastate in nature.

9. Under the merger proposal, and as a principal benefit thereof, NUI Corporation will acquire ownership of and operational control over significant natural gas storage facilities and related transmission assets located in southwestern Virginia, as well as ancillary businesses such as distribution and production operations.

10. No change in the identity of the North Carolina certificated public utility will occur as a result of the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company.

11. No change in the rates, terms, or conditions of service pursuant to which North Carolina customers are served will occur as a result of the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company.

12. There is no immediate risk and only nominal long-term risk to North Carolina ratepayers arising from the proposed merger of VGC Acquisition, Inc. into Virginia Gas Company.

13. The protective provisions agreed to by NUI North Carolina Gas and the Public Staff in the Stipulation are sufficient to ensure that there will be no adverse impact on the rates and service of NUI North Carolina Gas ratepayers as a result of the proposed merger and will serve to protect North Carolina ratepayers from any potential harm arising therefrom. These provisions are generally consistent with conditions imposed by the Commission in previous cases involving utility mergers, and are appropriate for use by the Commission in this docket.

14. The proposed merger will not serve to increase the market power of NUI Corporation in North Carolina and should not otherwise pose a threat to competition in North Carolina.

15. The benefits demonstrated by NUI North Carolina Gas outweigh the potential harms and risks associated with the proposed merger.

16. The merger between VGC Acquisition, Inc. and Virginia Gas Company, as proposed in NUI North Carolina Gas' application in this proceeding, is justified by the public convenience and necessity.

17. The issuance of shares by NUI Corporation, as proposed herein, is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

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

The findings set forth in Findings of Fact 1 through 4 are jurisdictional and/or informational in nature and are not contested by any party. They are supported by the Petition, the testimony and exhibits of the various witnesses, the records of the Commission in other proceedings and the Affidavits of Publication filed with the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The nature of the authorization sought by NUI North Carolina Gas in this docket is undisputed and is set forth in NUI North Carolina Gas' Petition and the exhibits attached thereto as well as the testimony and exhibits of Company witness Helfer.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The basis for this finding is found in G.S. 62-111(a) which provides that no "merger or combination affecting any public utility [shall] be made through acquisition or control by stock purchase or otherwise, except after application to and written approval by the Commission, which approval shall be given if justified by the public convenience and necessity." NUI North Carolina Gas' Petition recites that it is brought pursuant to G.S. 62-111(a) and expressly seeks Commission approval of the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company pursuant to that statute.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding is contained in NUI North Carolina Gas' Petition and the testimony of Company witness Helfer and is supported by a recent finding of the Commission in Docket No. G-3, Sub 224.

In its Petition, NUI North Carolina Gas indicates that, in addition to its regulated provision of natural gas service in North Carolina, through its other operating divisions, it is engaged in the "business of transporting, distributing and selling natural gas in the states of New Jersey (Elizabethtown Gas), Florida (City Gas Company), Pennsylvania (Valley Cities Gas), Maryland (Elkton Gas) and New York (Waverly Gas)." This assertion is confirmed by previous findings made by the Commission in other dockets involving NUI North Carolina Gas and in the description of NUI North Carolina Gas' utility business set forth in Form S-4 Registration Statement describing the proposed merger which was attached to the prepared direct testimony of Company Witness Helfer as Exhibit AMA-1.

In its Petition and in the Form S-4 Registration Statement describing the proposed merger, NUI Corporation, through its subsidiary and affiliate corporations, also indicates that it either operates or owns a significant interest in a number of businesses which provide unregulated services on a multi-state or, in some cases, a nationwide basis. These businesses include wholesale and retail energy sales, energy portfolio management, risk management, utility asset management, project development and energy consulting services, sales outsourcing, and business services among others.

The Hearing Commissioners take judicial notice of the fact that these findings are also consistent with the Commission's Order Granting Petition, issued on January 11, 2001 in Docket No. G-3, Sub 224.

The assertions contained in NUI North Carolina Gas' Petition in this regard and affirmed in the Company's Form S-4 Registration Statement relating to the merger are undisputed. No other party presented evidence on these matters.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is undisputed and is contained in NUI North Carolina Gas' Petition and the prepared direct and rebuttal testimony of Company witnesses Helfer. In the Petition, NUI North Carolina Gas indicated that Virginia Gas Company is a Delaware Corporation "engaged in the business of operating natural gas pipeline, production, storage and gathering facilities within the Commonwealth of Virginia." In her direct testimony, Ms. Helfer indicated that Virginia Gas Company is engaged in various energy related businesses including natural gas storage, transmission, production, distribution and gathering as well as the sale and delivery of propane. Ms. Helfer also indicated that all of Virginia Gas Company's assets and operations were located within Virginia and that these operations, a number of which are operated through subsidiary companies, are regulated by the Virginia Corporation Commission and the Federal Energy Regulatory Commission. Ms. Helfer's testimony in this regard is wholly supported by the description of Virginia Gas Company's business set forth in the Form S-4 Registration Statement for the proposed merger. The assertions regarding the nature and location of Virginia Gas Company's business contained in the Petition and the Company's testimony and exhibits is undisputed and no other party presented evidence thereon.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding is undisputed and is contained in NUI North Carolina Gas' Petition and the testimony and exhibits of Company witness Helfer.

In its Petition, NUI indicates its intent to acquire the pipeline, production, storage and gathering facilities of Virginia Gas Company and further indicates its belief that the acquisition thereof will diversify and strengthen its overall business position. In her prepared direct testimony, Company witness Helfer testified that NUI's acquisition of Virginia Gas Company will benefit NUI Corporation through the diversification of its business operations into complementary markets and businesses and that Virginia Gas Company's natural gas storage and transmission assets, in particular, are well suited to serve growing gas markets. This testimony is supported by the description of Virginia Gas Company's operations in the Form S-4 Registration Statement which indicates that it either now possesses or is in the process of developing significant natural gas storage facilities in southwestern Virginia and has constructed transmission facilities connecting those facilities to three interstate natural gas pipelines transiting parts of Virginia.

No other party filed testimony or presented other evidence regarding the nature of Virginia Gas Company's business or assets.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding is undisputed and is contained in the Petition and the testimony and exhibit of Company witness Helfer and the Stipulation entered into between the Company and the Public Staff.

The conclusion that no change in the certificated North Carolina public utility will result from the proposed merger is readily evident from the nature of the merger itself inasmuch as it involves an unregulated subsidiary of NUI Corporation – the certificated North Carolina public utility – merging into an unrelated foreign corporation. This conclusion is directly supported NUI North Carolina Gas' verified Petition in which NUI North Carolina Gas expressly states that the merger between VGC Acquisition, Inc. and Virginia Gas Company "will not affect the identity of NUI NC Gas as the certificated Public Utility under North Carolina law or the scope and nature of public utility service offered by NUI NC Gas to its North Carolina customers." This assertion is itself confirmed in the prefiled direct testimony of Company witness Helfer which provides that following the proposed restructuring "NUI NC Gas will continue to operate as it currently does" and that "Virginia Gas Company's operations will be run as an independent business through a separate subsidiary of NUI with no connection to NUI NC Gas."

Finally, in the Stipulation, the Company and the Public Staff stipulate that "there will be no change in the identity of the certificated entity providing public utility service in North Carolina" as a result of the proposed merger. No other party presented evidence on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding is undisputed and is contained in the Petition and the testimony and exhibit of Company witness Helfer.

In its verified Petition, NUI North Carolina Gas indicates that the proposed merger will not "impact or result in any change to the level, quality, price or terms of service provided by NUI North Carolina Gas to its North Carolina customers." This assertion is supported by the prefiled direct testimony of Company witness Abramovic which provides that "no change in any rates, terms or conditions of service will result from the reorganization."

This conclusion is also supported by the Stipulation entered into between the Public Staff and the Company wherein both agree that "there will be no change in . . . the rates terms or conditions upon which service rendered" by NUI North Carolina Gas as a result of the proposed merger.

In this regard, the Hearing Commissioners also note that NUI North Carolina Gas' Petition seeks no changes to the rates, terms or conditions of its service to North Carolina customers in this docket and that in any event, the rates, terms and conditions upon which NUI North Carolina Gas provides service are matters within the Commission's jurisdiction and cannot be changed or altered without Commission approval. No other party presented evidence on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence for these findings is contained in the testimony of Company witness Helfer, CUCA witness O'Donnell and the Stipulation between the Company and the Public Staff and is supported by the Hearing Commissioners' Findings of Fact Nos. 10 and 11 and the evidence supporting those findings.

The Stipulation between the Company and the Public Staff recites certain stipulated facts with which the Public Staff agrees relative to NUI North Carolina Gas' application in this proceeding. Among these are that "the ratepayers of NUI NC Gas will be protected from any negative impacts resulting from the proposed merger and there will be no change in the identity of the certificated entity providing public utility service in North Carolina or the rates terms or conditions upon which such service is rendered." This provision of the Stipulation is consistent with the Company's testimony and the nature of the proposed merger as discussed above in conjunction with Findings of Fact numbers 10 and 11. Based on the lack of relation between the proposed merger and NUI North Carolina Gas' certificated natural gas distribution and sales operations in North Carolina, the Hearing Commissioners conclude that the proposed merger will have no direct impact on North Carolina ratepayers.

In the Stipulation, and as an additional safeguard, NUI North Carolina Gas and the Public Staff also stipulate that any Commission order approving the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company should contain a number of provisions designed to protect North Carolina ratepayers from any adverse consequences that might conceivably result from the proposed merger. These provisions are:

(1) NUI NC Gas is required to seek out and buy all goods and services from the lowest cost provider of reasonably comparable goods and services. To this end, NUI NC Gas agrees to assess, on annual basis, the pricing for goods and services it receives from NUI Corporation (NUI) or other affiliates in order to permit NUI NC Gas to determine whether NUI NC Gas could have acquired reasonably comparable services at a lower market cost from nonaffiliated providers, or whether NUI NC Gas could have provided the service itself at lower cost.

(2) NUI NC Gas shall file a revised cost allocation manual with the North Carolina Utilities Commission (NCUC) within twelve months after closing describing how all direct, indirect, and other costs will be charged to capital projects, nonjurisdictional operations, and affiliates. In that connection, NUI NC Gas will perform a detailed review of the common costs to be allocated and allocation factors to be used and shall provide a list of items considered to be the shared services of NUI NC Gas and the basis for each determination at the time it files its revised cost allocation manual.

(3) For goods and services provided to NUI NC Gas by NUI and/or affiliated companies, NUI will directly assign costs when possible and will allocate the costs that cannot be directly assigned in a manner that results in North Carolina ratepayers paying no more than their proportionate share.

(4) NUI shall file an annual report of transactions between NUI NC Gas and its affiliates that relate to service provided to North Carolina customers in a format prescribed by the NCUC. The first report on affiliated transactions shall be filed on March 31, 2002, for activity through December 31, 2001, and annually thereafter on March 31. Transactions affecting NUI's regulated operations shall be reviewed regularly by its internal auditors. All workpapers shall be available for review by the Public Staff and the NCUC Staff.

(5) NUI shall keep its accounting books and records in a manner that will allow all components of the cost of capital for NUI's North Carolina regulated operations to be identified easily and clearly on a separate basis.

(6) NUI will identify at the time of NUI NC Gas' next rate case the amount of NUI's equity investment in its North Carolina regulated operations that is reflected in the accounting records.

(7) To the extent the cost rates of NUI's long-term debt (more than one year), short-term debt (one year or less) or preferred stock are or have been adversely affected by the merger, through a downgrade or otherwise, a replacement cost rate to remove the effect will be used for all purposes affecting rates and charges. This replacement cost rate will be applicable to all financings, refundings, and refinancings. This procedure will be effective through NUI NC Gas' next general rate case. As part of NUI NC Gas' next general rate case, any future procedure relating to a replacement cost calculation will be determined. This regulatory condition does not indicate a preference by any party for any specific debt rating or preferred stock rating for NUI on current or prospective bases.

(8) NUI will identify as clearly as possible long-term debt (of more than one year duration) issued by NUI, as appropriate, with either (a) the assets that are or will be utilized to provide service to NUI's regulated utility customers or (b) NUI's existing debt to be replaced with the new debt issuance.

(9) These regulatory conditions do not supersede any orders or directives that have been or will be issued by the NCUC regarding the issuance of specific securities by NUI. The issuance of securities after the announcement of the merger does not restrict the NCUC's right to review, and if deemed appropriate, adjust NUI's and, thereby, NUI NC Gas' cost of capital for ratemaking purposes for the effect of these securities.

(10) Consistent with past practices, NUI generally will continue to be exempt from applying for approval from the NCUC for its securities issuances.

(11) All costs of the merger and all direct and indirect corporate cost increases (including those that may be assigned to NUI, a service company or any affiliate), if any, attributable to the merger, will be excluded from NUI NC Gas' utility accounts, and shall be treated for accounting and ratemaking purposes so that they do not affect NUI NC Gas' natural gas rates and charges. For purposes of this condition, the term "corporate cost increases" is defined as costs in excess of the level that NUI NC Gas would have incurred using prudent business judgment had the merger not occurred.

(12) Any acquisition adjustment that results from the business combination of VGC Acquisition and VGC will be excluded from NUI NC Gas' utility accounts, and treated for accounting and ratemaking purposes so that it does not affect NUI NC Gas' natural gas rates and charges.

(13) In accordance with North Carolina law, NUI will provide the NCUC and the Public Staff full access to the books and records of NUI and NUI NC Gas, their affiliates, and nonutility operations.

(14) The Public Staff and NUI will review the need for a code of conduct and, if needed, will negotiate and jointly recommend a code of conduct to the NCUC by December 1, 2001. NUI, NUI NC Gas, their affiliates, and NUI NC Gas' nonregulated operations shall be bound by any code of conduct approved by the NCUC with respect to transactions impacting the rates, terms or conditions of service to North Carolina customers and such a code shall be considered the minimum conditions to which the merged company is agreeing.

(15) NUI NC Gas will continue its commitment to providing superior natural gas service to North Carolina customers following the merger and will continue to work with the Public Staff to resolve any issues related to gas service.

(16) NUI, NUI NC Gas and their affiliates shall file a current five-year plan for new or expanded North Carolina gas pipeline facilities costing $50,000 or more with the NCUC in conjunction with NUI NC Gas' biennial expansion report. The filing shall also describe each inquiry received from a party interested in locating gas-fired electric generation in North Carolina and report on the status of each inquiry (confidentially if necessary).

(17) NUI agrees to provide reasonable notice, prior to the commencement of any construction related activity, including the acquisition of any rights-of-way, of its intent to construct facilities to provide service to an electric generation plant. Any application for a certificate of public convenience and necessity filed with the NCUC by NUI or an affiliate shall incorporate details with respect to the routing of any new or expanded gas pipeline or other facilities

required to serve the proposed electric generating plant and details about any proposed pipeline routing and specifications related to any new or expanded natural gas facilities needed to provide gas and/or transportation service to the proposed electric generating plant.

(18) NUI and NUI NC Gas shall utilize reasonably competitive solicitation procedures to determine future long-term sources of interstate pipeline capacity and supply. The determination of the appropriate source(s) for the interstate pipeline capacity and supply shall be made by NUI NC Gas on the basis of the benefits and costs of such source(s) specifically to NUI NC Gas' gas customers.

(19) NUI NC Gas shall not recover from ratepayers the margins lost as the result of bypass by an interstate gas pipeline in which NUI or any affiliate has an ownership interest.

(20) Unless expressly superseded by the regulatory conditions contained herein, the conditions, stipulations, and agreements that were agreed to by NUI and NUI NC Gas and filed on November 1, 2000, in Docket No. G-3, Sub 224, remain in full force and effect.

CUCA witness O'Donnell perceives some risk from the merger based on his perception of the financial risk associated with Virginia Gas Company's current business status. Specifically, Mr. O'Donnell indicates that as a result of Virginia Gas Company's technical defaults under its loan agreements, NUI's acquisition of Virginia Gas Company may make "NUI a riskier company in which to invest" and that "when NUI files a rate case, [this] increased risk of NUI will be reflected in higher debt and equity costs". In contrast to this concern, the evidence of NUI North Carolina Gas indicates that (1) the defaults of Virginia Gas under its loan agreements are based on technical earnings to debt ratio covenants that the company failed to reach, (2) that the primary cause of its failure to meet these ratios is significant new expansion of Virginia Gas Company's facilities, (3) that Virginia Gas Company has made all required payments of principal and interest in a timely manner, (4) that the loans in question have not been called, and (5) that NUI has provided an interim financing facility for Virginia Gas Company pending the closing of the proposed merger.

After carefully reviewing all of the evidence on this issue, the Hearing Commissioners conclude that there is some long term risk to North Carolina ratepayers associated with the acquisition of Virginia Gas Company by NUI, however, that risk is only nominal in nature and the sort of business risk faced in all merger situations, i.e., the risk that the proposed merger will not provide the benefits upon which the merger was premised. At this point in time, this risk does not provide any basis for rejecting the proposed merger. In this regard, the Hearing Commissioners would note that the existence of a long term potential risk from the acquisition in no way undercuts their previous conclusions that the merger will have no immediate impact on North Carolina ratepayers and would further note that the Commission has ultimate control over whether any negative impact from the merger would be passed on to North Carolina ratepayers in a subsequent rate proceeding. Further, we conclude that any risk of the nature identified by Mr. O'Donnell is mitigated by NUI North Carolina Gas' specific agreement to hold North Carolina ratepayers harmless from any negative consequences of the merger as a result of the conditions agreed to in the Stipulation with the Public Staff which are similar to other ratepayer protection provisions the Commission has approved in previous utility merger proceedings. As a result of the foregoing, NUI North Carolina Gas' North Carolina ratepayers are protected both from any immediate adverse impacts on rates and services as well as from any future harm that could result from the proposed merger of VGC Acquisition, Inc. and Virginia Gas Company.

The Hearing Commissioners find it appropriate to condition the order in this proceeding on the stipulated ratepayer protection provisions.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding is contained in the testimony of Company witness Helfer and Company witness Bohi, a professional economist hired by NUI North Carolina Gas to conduct a Market Power Study of the proposed merger between VGC Acquisition, Inc. and Virginia Gas Company. In her prepared direct testimony, Ms. Helfer indicated that Virginia Gas Company and NUI operate in distinct geographic and business markets and have no existing business relationship. Further, Ms. Helfer indicates that following the merger, Virginia Gas Company will be operated, on at least an initial basis, as an entirely separate business entity from the rest of the NUI companies. Finally, Ms. Helfer notes that both NUI North Carolina Gas' utility operations in North Carolina (and other states) and Virginia Gas Company's distribution, transmission and storage operations in Virginia are regulated as to rates and conditions of service by various regulatory agencies having jurisdiction over those respective facilities and operations. In his prepared direct testimony, Dr. Bohi testified that given the context of the proposed merger and the configuration of pipelines and related facilities in North Carolina, the proposed merger posed no threat to competition in North Carolina. Dr. Bohi's conclusion regarding the lack of anticompetitive effects associated with the proposed merger is supported by his Market Power Study attached to his prepared direct testimony which calculates a Herfindal-Hirschman Index (HHI) value of 656 for the merger. According to Dr. Bohi, that value is well below the threshold HHI level for an unconcentrated market of 1,000. Dr. Bohi also cites the lack of action by the Federal Trade Commission in connection with NUI North Carolina Gas' premerger Hart-Scott-Rodino filing, the fact that no change in market participants or share will occur in the relevant market as a result of the merger, the fact that both NUI North Carolina Gas and Virginia Gas Company are regulated with respect to their services, and the distinct markets in which NUI North Carolina Gas and Virginia Gas Company operate as further cumulative evidence that the proposed merger will have no anti-competitive effects.

No other party presented evidence on this matter.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding and conclusion is contained in the Company's Petition, in the testimony of Company witness Helfer, in the testimony of CUCA witness O'Donnell and in the Stipulation.

In the Petition, NUI North Carolina Gas asserts NUI's management's belief that the proposed merger will "serve to diversify and strengthen the overall business position of the NUI companies (including NUI Gas and VGC)", will enhance "their ability to operate in the changing regulatory and economic environment facing public utilities" and will "have no negative economic impact on the service provided by NUI NC Gas to North Carolina ratepayers." In her prepared direct testimony, Company witness Helfer indicated that the proposed merger would benefit NUI through the diversification and broadening of its business operations into an area related to, but not overlapping, its primary business of intrastate natural gas sales, transportation and distribution. In particular, Ms. Helfer indicated NUI North Carolina Gas' belief that Virginia Gas Company's intrastate transmission and natural gas storage facilities were well-positioned to serve growing local and national natural gas markets and that the Company would benefit from the additional revenues generated by Virginia Gas Company. Ms. Helfer's testimony is supported by the description of Virginia Gas Company's operations set forth in the Form S-4 Registration Statement attached to her prepared direct testimony as Exhibit AMA-1 which indicates that Virginia Gas Company's developing salt storage facilities may ultimately have a capacity of well in excess of 10 Bcf of natural gas and that Virginia Gas Company's intrastate transmission facilities connect these storage fields to three interstate natural gas pipelines in southwestern Virginia. Ms. Helfer also indicates that NUI expects to be able to achieve a net savings of approximately $760,000 per year in historic cost incurred by Virginia Gas Company as a result of the merger. Ms. Helfer's testimony and the Form S-4 Registration Statement also indicates that NUI will be able to provide needed capital for Virginia Gas Company's expanding operations at favorable rates. Ms. Helfer also testified that the merger may ultimately provide an indirect benefit to North Carolina ratepayers as a result of a stronger, more diverse and economically stable NUI Corporation and through the contribution of corporate overhead payments by the new Virginia Gas Company operations.

In his prepared direct testimony, CUCA witness O'Donnell, in addition to his concern over the economic condition of Virginia Gas Company discussed above, argues that NUI North Carolina Gas has failed to conduct an adequate cost-benefit analysis of the proposed merger and/or to identify adequate savings that will result from the merger. Mr. O'Donnell further contends that the Commission should order NUI North Carolina Gas to share any identified savings from the merger allocable to North Carolina on up to a 50% basis. The Hearing Commissioners have carefully considered Mr. O'Donnell's concerns but conclude that NUI North Carolina Gas has presented adequate evidence regarding projected savings expected to arise from the merger and further conclude that due to the total nature of the proposed merger transaction and the savings that are expected to result therefrom, no sharing of those savings with North Carolina ratepayers is appropriate in this instance. These conclusions are based on the following factors. First, the evidence presented by the Company, and to a lesser extent by CUCA, clearly demonstrates that NUI formed an integration team in October of 2000 to, among other things, identify areas of potential cost savings and efficiencies that may be achieved as a result of the merger. Based on the evidence presented, this team has taken a broad look at all possible areas of potential savings that could accrue from the merger and has, to date, identified approximately $760,000 per year of discrete savings expected to result from the merger. These savings are the result of the elimination of costs historically incurred solely by Virginia Gas Company and attributable to its corporate and business operations in Virginia. This team has identified no "overlapping function" cost savings or labor cost reductions expected to result from the merger as hypothesized by Mr. O'Donnell. To the contrary, the evidence indicates that expense items such as labor and employee costs associated with operating Virginia Gas Company are increasing. The apparent reason for the lack of overlapping function savings is the relatively small nature of Virginia Gas Company's labor force (60 people), the multiple functions performed by many employees including a high degree of operational functions, the geographic separation of Virginia Gas Company from NUI's other operations, the expanding nature of Virginia Gas Company's operations and NUI's decision to operate the acquired company as an independent entity on an initial basis. Second, the merger will have no effect on and does not involve the sale, acquisition or other disposition of any facilities, employees or operations used to provide service to North Carolina ratepayers and the facilities and operations to be acquired have no relation at all to service provided to North Carolina ratepayers. Third, NUI is not seeking an acquisition adjustment or to recover any of the costs of this merger from North Carolina ratepayers and has affirmatively taken steps to insulate North Carolina ratepayers from any detrimental effects of the merger through its agreement to the ratepayer protection measures in the Stipulation. Accordingly, the risks and costs of the merger fall completely on NUI's shareholders. Fourth, imposing a savings sharing requirement on NUI North Carolina Gas in this case may impinge on the jurisdiction of the Virginia Corporation Commission inasmuch as the cost savings expected to accrue from the merger would appear to be savings of historical Virginia Gas Company expenses.

Finally, the Stipulation entered into between the Public Staff and the Company indicates that, after review of NUI North Carolina Gas' Petition and testimony in this proceeding, the Public Staff agreed that "NUI reasonably believes that the proposed merger will benefit the Company and may have beneficial impacts on North Carolina ratepayers."

The Hearing Commissioners have carefully reviewed the testimony and exhibits of Company witness Helfer and CUCA witness O'Donnell, as well as the Stipulation, and conclude that the benefits demonstrated by NUI North Carolina Gas from the proposed merger outweigh any potential harms or risks identified in the record. These benefits include the diversification and stability arising from the acquisition of complementary natural gas facilities and operations in a new geographic market adjacent to NUI's existing operations, the cost savings to the combined company associated with a reduction in Virginia Gas Company's historical operating costs, the ability of NUI to provide needed capitalization to Virginia Gas Company at favorable rates, and the business opportunity presented through the acquisition of significant interstate natural gas storage assets in the mid-Atlantic region. It is also apparent from the record in this proceeding that the Company's management has carefully considered this transaction and has reasonably concluded that the benefits of the merger in this case outweigh the potential detriments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding is contained in the Petition, in the prefiled testimony and exhibit of Company witness Helfer and CUCA witness O'Donnell and in the Stipulation entered into between the Public Staff and the Company. This finding is supported by the evidence and discussion supporting findings and conclusions 10 through 15.

In summary, the Hearing Commissioners have previously found, and supported their findings, that:

(1) The proposed merger will have no significant negative market power or anti-competitive impacts or effects.

(2) The proposed merger of VGC Acquisition, Inc. and Virginia Gas Company will have no effect on the identity of the certificated public utility providing natural gas service to North Carolina ratepayers and the rates, terms and conditions of such service will not change as a result of the proposed merger.

(3) There is no direct risk and only nominal indirect risk to North Carolina ratepayers from the proposed merger.

(4) NUI North Carolina Gas' North Carolina ratepayers will be held harmless from any detrimental impacts of the proposed merger under the ratepayer protection provisions that NUI and the Public Staff have agreed should be made a part of any order approving the proposed merger of VGC Acquisition, Inc. and Virginia Gas Company.

(5) The benefits demonstrated by NUI North Carolina Gas outweigh the potential harms and risks associated with the proposed transactions.

On the basis of these findings, and the evidence supporting them, the Hearing Commissioners conclude that NUI's proposal to merge its unregulated subsidiary VGC Acquisition, Inc. into Virginia Gas Company will provide positive benefits to NUI as well as potential benefits to its ratepayers. The Hearing Commissioners also conclude that what nominal risk to North Carolina ratepayers may be associated with the proposed transaction has been mitigated by the ratepayer protection provisions set forth in the Stipulation between the Company and the Public Staff and the fact that the merger will have no direct impact on North Carolina ratepayers who will see no change in either the entity providing service to them or the rates, terms or conditions of that service after the merger. To the extent that any future event associated with or arising out of the merger may threaten harm to North Carolina ratepayers, that risk has either been provided for in the stipulated ratepayer protection provisions or is within the jurisdiction and, therefore, ultimate control of this Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding is contained in the Petition, the testimony of Company witness Helfer and in the prior findings of this Commission.

In the Petition, NUI North Carolina Gas asserts that the issuance of shares by NUI Corporation in conjunction with the proposed merger is exempt from the requirements of G.S. 62-161 and Commission Rule R1-16 under the holding of the North Carolina Supreme Court in State ex rel. Utilities Commission v. Southern Bell Tel. & Tel. Co., 288 N.C. 201, 217 S.E.2d 543 (1975). In that opinion, the North Carolina Supreme Court held that the issuance of shares by a foreign utility with the majority of its operations and assets outside the state of North Carolina is not subject to G.S. 62-161 or Commission Rule R1-16.

In the past, the Commission has determined on several occasions that the issuance of shares by NUI North Carolina Gas – a certificated North Carolina public utility – is not subject to G.S. 62-161 and Commission Rule R1-16 on the basis of the Southern Bell opinion because NUI is a foreign corporation with the majority of its assets and operations outside the state of North Carolina. In the Matter of Applications for Authority to Transfer Control of International Telephone Group, Inc. to NUI Capital Corp., Order Approving Transfer of Control, Docket No. G-3, Sub 219 (October 14, 1999). More recently, the Commission determined that the issuance of shares by an NUI affiliate in connection with a corporate reorganization of the NUI Companies (in which the ownership of the certificated North Carolina public utility changed) was not subject to G.S. 62-161 and Commission Rule R1-16. In the Matter of Application of NUI Corporation for Approval of Exchange of Shares Between NUI Holding Company and NUI Corporation, Order Granting Exchange, Docket No. G-3, Sub 224 (January 11, 2001).

In this case, the testimony of Company witness Helfer is that the North Carolina allocated share of NUI Corporation's utility operations is approximately 4% of the Company total indicating that the vast majority of NUI's total corporate assets and operations are outside the state of North Carolina. Given this fact and the additional fact that the proposed share issuance in this docket relates to a transaction occurring and properties located wholly outside North Carolina, the Hearing Commissioners conclude that NUI Corporation's proposed issuance of shares in this instance is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

CONCLUSIONS OF LAW

1. Under the relevant statute, G.S. 62-111, the Commission has broad authority to review all aspects of the proposed merger and to balance all potential benefits and costs of the transactions to determine if they should be authorized.

2. Approval should be given to NUI North Carolina Gas' proposed merger of VGC Acquisition, Inc. and Virginia Gas Company only if sufficient conditions are imposed to ensure that it will have no known adverse impact on the rates and service of NUI North Carolina Gas' ratepayers, its ratepayers are protected as much as possible from potential harm, and its ratepayers will receive sufficient benefit from the proposed activities to offset any potential costs, risks and harms.

3. Based on its application of the foregoing standards to the facts of this case, with particular attention paid to the conditions approved herein, the Hearing Commissioners conclude that the requirements of G.S. 62-111 have been met and that the proposed merger of VGC Acquisition, Inc. and Virginia Gas Company is justified by the public convenience and necessity and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed merger of VGC Acquisition, Inc. and Virginia Gas Company is hereby authorized and approved upon the following conditions:

NATURAL GAS - MERGERS

(1) NUI NC Gas is required to seek out and buy all goods and services from the lowest cost provider of reasonably comparable goods and services. To this end, NUI NC Gas agrees to assess, on annual basis, the pricing for goods and services it receives from NUI Corporation (NUI) or other affiliates in order to permit NUI NC Gas to determine whether NUI NC Gas could have acquired reasonably comparable services at a lower market cost from nonaffiliated providers, or whether NUI NC Gas could have provided the service itself at lower cost.

(2) NUI NC Gas shall file a revised cost allocation manual with the North Carolina Utilities Commission (NCUC) within twelve months after closing describing how all direct, indirect, and other costs will be charged to capital projects, nonjurisdictional operations, and affiliates. In that connection, NUI NC Gas will perform a detailed review of the common costs to be allocated and allocation factors to be used and shall provide a list of items considered to be the shared services of NUI NC Gas and the basis for each determination at the time it files its revised cost allocation manual.

(3) For goods and services provided to NUI NC Gas by NUI and/or affiliated companies, NUI will directly assign costs when possible and will allocate the costs that cannot be directly assigned in a manner that results in North Carolina ratepayers paying no more than their proportionate share.

(4) NUI shall file an annual report of transactions between NUI NC Gas and its affiliates that relate to service provided to North Carolina customers in a format prescribed by the NCUC. The first report on affiliated transactions shall be filed on March 31, 2002, for activity through December 31, 2001, and annually thereafter on March 31. Transactions affecting NUI's regulated operations shall be reviewed regularly by its internal auditors. All workpapers shall be available for review by the Public Staff and the NCUC Staff.

(5) NUI shall keep its accounting books and records in a manner that will allow all components of the cost of capital for NUI's North Carolina regulated operations to be identified easily and clearly on a separate basis.

(6) NUI will identify at the time of NUI NC Gas' next rate case the amount of NUI's equity investment in its North Carolina regulated operations that is reflected in the accounting records.

(7) To the extent the cost rates of NUI's long-term debt (more than one year), short-term debt (one year or less) or preferred stock are or have been adversely affected by the merger, through a downgrade or otherwise, a replacement cost rate to remove the effect will be used for all purposes affecting rates and charges. This replacement cost rate will be applicable to all financings, refundings, and refinancings. This procedure will be effective through NUI NC Gas' next general rate case. As part of NUI NC Gas' next

general rate case, any future procedure relating to a replacement cost calculation will be determined. This regulatory condition does not indicate a preference by any party for any specific debt rating or preferred stock rating for NUI on current or prospective bases.

(8) NUI will identify as clearly as possible long-term debt (of more than one year duration) issued by NUI, as appropriate, with either (a) the assets that are or will be utilized to provide service to NUI's regulated utility customers or (b) NUI's existing debt to be replaced with the new debt issuance.

(9) These regulatory conditions do not supersede any orders or directives that have been or will be issued by the NCUC regarding the issuance of specific securities by NUI. The issuance of securities after the announcement of the merger does not restrict the NCUC's right to review, and if deemed appropriate, adjust NUI's and, thereby, NUI NC Gas' cost of capital for ratemaking purposes for the effect of these securities.

(10) Consistent with past practices, NUI generally will continue to be exempt from applying for approval from the NCUC for its securities issuances.

(11) All costs of the merger and all direct and indirect corporate cost increases (including those that may be assigned to NUI, a service company or any affiliate), if any, attributable to the merger, will be excluded from NUI NC Gas' utility accounts, and shall be treated for accounting and ratemaking purposes so that they do not affect NUI NC Gas' natural gas rates and charges. For purposes of this condition, the term "corporate cost increases" is defined as costs in excess of the level that NUI NC Gas would have incurred using prudent business judgment had the merger not occurred.

(12) Any acquisition adjustment that results from the business combination of VGC Acquisition and VGC will be excluded from NUI NC Gas' utility accounts, and treated for accounting and ratemaking purposes so that it does not affect NUI NC Gas' natural gas rates and charges.

(13) In accordance with North Carolina law, NUI will provide the NCUC and the Public Staff full access to the books and records of NUI and NUI NC Gas, their affiliates, and nonutility operations.

(14) The Public Staff and NUI will review the need for a code of conduct and, if needed, will negotiate and jointly recommend a code of conduct to the NCUC by December 1, 2001. NUI, NUI NC Gas, their affiliates, and NUI NC Gas' nonregulated operations shall be bound by any code of conduct approved by the NCUC with respect to transactions impacting the rates, terms or conditions of service to North Carolina customers and such a code shall be considered the minimum conditions to which the merged company is agreeing.

(15) NUI NC Gas will continue its commitment to providing superior natural gas service to North Carolina customers following the merger and will continue to work with the Public Staff to resolve any issues related to gas service.

(16) NUI, NUI NC Gas and their affiliates shall file a current five-year plan for new or expanded North Carolina gas pipeline facilities costing $50,000 or more with the NCUC in conjunction with NUI NC Gas' biennial expansion report. The filing shall also describe each inquiry received from a party interested in locating gas-fired electric generation in North Carolina and report on the status of each inquiry (confidentially if necessary).

(17) NUI agrees to provide reasonable notice, prior to the commencement of any construction related activity, including the acquisition of any rights-of-way, of its intent to construct facilities to provide service to an electric generation plant. Any application for a certificate of public convenience and necessity filed with the NCUC by NUI or an affiliate shall incorporate details with respect to the routing of any new or expanded gas pipeline or other facilities required to serve the proposed electric generating plant and details about any proposed pipeline routing and specifications related to any new or expanded natural gas facilities needed to provide gas and/or transportation service to the proposed electric generating plant.

(18) NUI and NUI NC Gas shall utilize reasonably competitive solicitation procedures to determine future long-term sources of interstate pipeline capacity and supply. The determination of the appropriate source(s) for the interstate pipeline capacity and supply shall be made by NUI NC Gas on the basis of the benefits and costs of such source(s) specifically to NUI NC Gas' gas customers.

(19) NUI NC Gas shall not recover from ratepayers the margins lost as the result of bypass by an interstate gas pipeline in which NUI or any affiliate has an ownership interest.

(20) Unless expressly superseded by the regulatory conditions contained herein, the conditions, stipulations, and agreements that were agreed to by NUI and NUI NC Gas and filed on November 1, 2000, in Docket No. G-3, Sub 224, remain in full force and effect.

2. That the issuance of shares by NUI Corporation in connection with the proposed merger is exempt from the requirements of G.S. 62-161 and Commission Rule R1-16;

3. That NUI North Carolina Gas shall file a written notice in this docket within thirty (30) days after consummation of the transaction approved herein; and

4. That this docket shall remain open for the purpose of receiving the notice required hereinabove.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

Commissioner Pittman resigned from the Commission effective January 23, 2001, and did not participate in this decision.

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DOCKET NO. G-40, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Proceeding to Determine Whether	)	
Frontier Energy, LLC, Is Providing	)	ORDER ON
Adequate Service to Certain	)	FORFEITURE
Counties in Its Franchise Territory	)	PROCEEDING

BY THE COMMISSION: In June 1995, the North Carolina General Assembly amended G.S. 62-36A(b) to provide that "any local distribution company that the Commission determines is not providing adequate service to at least some portion of each county within its franchise territory ... within three years of the time the franchise territory is awarded ... shall forfeit its exclusive franchise rights to that portion of its territory not being served." This amendment is commonly referred to as the "use-it-or-lose-it" legislation.

On March 19, 1996, the Commission adopted Rule R6-63 to implement the statute. The Rule provides for a review proceeding to be held following the applicable date for forfeiture. Rule R6-63(d) provides that even if a natural gas utility has not actually begun providing service as of the forfeiture date, the utility will be allowed a two-year grace period if it has met certain conditions by the forfeiture date. If these conditions are met, the utility will be given two years from the forfeiture date to provide service.

Frontier Utilities of North Carolina, Inc., which is now Frontier Energy, LLC (both hereinafter cited as Frontier), was granted a certificate of public convenience and necessity to serve Surry, Watauga, Wilkes, and Yadkin Counties by Order dated January 30, 1996, in Docket Nos. G-38 and G-9, Sub 357. The North Carolina Supreme Court affirmed this Order by an opinion filed July 24, 1997, the mandate for which was dated August 3, 1997.

On August 16, 1996, the Commission issued its Final Order Assigning Franchises and Issuing Certificates in Docket No. G-100, Sub 69, by which the Commission franchised previously unfranchised areas of the State for natural gas service. By that Order, the Commission issued certificates of public convenience and necessity to Frontier to provide natural gas service in Ashe and Alleghany Counties. Frontier's franchise for Surry, Watauga, Wilkes, and Yadkin Counties was the basis for the assignment of Ashe and Alleghany to Frontier, and the Commission has therefore interpreted the August 16, 1996 assignment of Ashe and Alleghany to Frontier as contingent upon Frontier's keeping its franchise for Surry, Watauga, Wilkes, and Yadkin for purposes of G.S. 62-36A(b).

Frontier was granted a certificate of public convenience and necessity to serve Warren County by Order dated March 27, 1997, in Docket No. G-38, Sub 1.

By Order dated November 13, 2000, the Commission initiated a review proceeding in this docket and scheduled a hearing to determine whether Frontier was providing adequate service to at least some portion of each county in its franchise territory as of the applicable date and, if not, to order that Frontier forfeit its exclusive franchise rights to that portion of its territory not being served. This proceeding involves Frontier's franchise territory in Surry, Watauga, Wilkes, Yadkin, Ashe, Alleghany, and Warren Counties. As set forth in the November 13 Order, the Commission has concluded that the applicable date for Surry, Watauga, Wilkes, Yadkin, Ashe and Alleghany Counties is August 3, 2000, and that the applicable date for Warren County is March 27, 2000.

The November 13 Order scheduled a hearing and provided for public notice. The Order and notice stated that the hearing would be canceled if no issues were raised by testimony or written statements filed with the Commission. Frontier filed the testimony of William Purcell in this proceeding on December 21, 2000. On January 18, 2001, the Public Staff filed its Statement of Position. Frontier filed a Response agreeing with the Public Staff position on January 29, 2001.

On February 2, 2001, the Commission issued its Order Canceling Hearing, canceling the hearing in this docket and providing that the docket would be decided on the testimony and written statements filed herein.

Based on the prefiled testimony, the filings herein and the records of the Commission, the Commission makes the following:

FINDINGS OF FACT

1. Frontier is a public utility engaged in the business of owning and operating transmission and distribution lines and other facilities for furnishing natural gas service to the public in its franchise territory in North Carolina, pursuant to the certificates of public convenience and necessity granted by this Commission.

2. Frontier's franchise territory includes Surry, Watauga, Wilkes, Yadkin Counties which were franchised to Frontier by Commission Order of January 30, 1996, which was affirmed by a Supreme Court opinion, the mandate for which was dated August 3, 1997. The applicable date by which Frontier had to be providing adequate service to at least some portion of Surry, Watauga, Wilkes, and Yadkin Counties to avoid the loss of its exclusive franchise rights for these counties is August 3, 2000.

3. Frontier's franchise territory also includes Ashe and Alleghany Counties, which were assigned to Frontier by Commission Order of August 16, 1996. For purposes of G.S. 62-36A(b), the Commission interprets the August 16, 1996 Order assigning Ashe and Alleghany to Frontier as contingent upon Frontier's keeping its franchise for Surry, Watauga, Wilkes, and Yadkin Counties. Therefore, the applicable date by which Frontier had to be providing adequate service to at least some portion of Ashe and Alleghany Counties to avoid the loss of its exclusive franchise rights for these counties is August 3, 2000.

4. Frontier's franchise territory also includes Warren County, which was franchised to Frontier by Order dated March 27, 1997. The applicable date by which Frontier had to be providing adequate service to at least some portion of Warren County to avoid the loss of its exclusive franchise rights for the county is March 27, 2000.

5. Commission Rule R6-63(d) provides that a natural gas utility will be deemed to be "providing adequate service," even though it "has not actually begun providing service," if the following conditions are met:

(i) the natural gas utility has completed a substantial amount of design process/service for the construction of natural gas facilities into at least some portion of the county, such as the preparation of engineering design for pipe size and capacity parameter, rectifier facilities, route location, materials specifications, construction specifications and drawings by an engineer sufficient to indicate the facilities to be built; or

(ii) the natural gas utility has begun to acquire rights-of-way for the construction and operation of natural gas facilities in the county; or

(iii) by at least six months before the applicable date set forth in subsection (b)(i) or (ii) above, the natural gas utility filed an application that complies with the Commission's applicable orders and rules for use of expansion funds for the construction of facilities into at least some portion of the county; and

(iv) it appears likely that the construction of the facilities will be completed and service will be provided within two years of the applicable date set forth in subsection (b)(i) or (ii) above.

If these conditions are met, no forfeiture will be ordered and the natural gas utility will be given two years to complete construction and begin providing service.

Wilkes, Surry and Yadkin Counties

6. As of August 3, 2000, Frontier had natural gas facilities in place and in operation in Wilkes, Surry and Yadkin Counties and was serving customers.

Watauga and Ashe Counties

7. Frontier plans to serve Watauga County by a transmission line from Wilkesboro. The original plan for serving Watauga County did not contemplate serving any other counties beyond Watauga. After Ashe and Alleghany were assigned to Frontier, Frontier revised its plans to increase the size of the transmission line from Wilkesboro to Deep Gap in Watauga County, so that Ashe and Alleghany could be served off this line.

8. Frontier filed an application to use natural gas bond funds to serve both Ashe and Alleghany on December 22, 1999. Later, Frontier decided to divide up the project, and an amended application applicable to just Ashe County, but including an allocated portion of the line to Deep Gap, was filed on May 3, 2000. This amended application included a detailed description of physical facilities, an engineering study, a proposed construction schedule and project specifications for construction to Deep Gap in Watauga County and from there on into Ashe County. At about the same time, the same level of design process/service work was completed for construction from Deep Gap to Boone in Watauga County.

9. The Commission approved use of natural gas bond funds to serve Ashe County on June 29, 2000. Frontier then began work on the project. Pipe was ordered, and by August 3, 2000, all the pipe necessary for the line to Deep Gap and, from there, the lines to Boone and to Jefferson in Ashe County was in Frontier's construction yard. Preliminary engineering for the Blue Ridge Parkway portion of the project was completed in July 2000. Also in July 2000, a field constructability review of the entire project was conducted and specific maps were prepared for right-of-way acquisition.

10. Since August 3, 2000, design and permitting has continued, easements and rights-of-way have been acquired, and construction has begun. Frontier foresees service to Appalachian State University in Watauga and to industrial customers in Ashe by the end of 2001 and construction of distribution lines to residential and small commercial customers in both counties in 2002.

Alleghany County

11. As of August 3, 2000, Frontier had neither completed a substantial amount of the design process/service work for Alleghany County, nor acquired rights-of-way for the county, nor renewed its request for bond funds to serve the county. Frontier hopes to reapply for the franchise and for natural gas bond funds to serve Alleghany County in the future.

Warren County

12. On September 20, 1999, Frontier applied for approval to use proceeds from natural gas bond funds to provide service in Warren County; the Commission approved this request by order of March 16, 2000. Frontier completed Phase I of the Warren County project -- 15 miles of six-inch pipe from the Transco tap near the Virginia border in Warren County to the Soul City-Manson area -- by mid-March of 2000, although no customers were in fact being served as of March 27, 2000. Since March 27, 2000, Frontier has completed Phase II of the project, extending transmission lines to Norlina and Warrenton and installing distribution lines in Norlina. At the time of the prefiled testimony, customers were being served in Warren County, including residential customers and the Chesapeake cardboard facility, and Frontier was continuing to install distribution lines and to connect customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence for these findings is in the records of the Commission and in the applicable statute and Commission Rule.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence is support of this finding is found in the pre-filed testimony of Frontier witness Purcell. Witness Purcell testified that as of August 3, 2000, Frontier was providing natural gas service to approximately twenty-five customers in Wilkes, Surry and Yadkin counties. Frontier had placed over 95 miles of ten-inch transmission pipe in the ground, along with more than 60 miles of two-inch, four-inch and six-inch distribution pipe. He named customers who were being served as of August 3, including Sara Lee in Yadkinville, Cross Creek Apparel in Mt. Airy, Tyson Poultry

Feedmill in Roaring River, the Tyson poultry processing plant in North Wilkesboro, Candle Corporation near Elkin, Carolina Mirror in North Wilkesboro, and the Tyson Poultry Hatchery in Hays. The Public Staff took no issue with Frontier as to these counties.

The Commission therefore concludes that Frontier was providing adequate service to at least some portion of Wilkes, Surry and Yadkin counties as of August 3, 2000 and that no forfeiture should be ordered as to these counties.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7-10

Frontier witness Purcell testified that the original plans did not contemplate extending natural gas service to Ashe or Alleghany County and, accordingly, the original line to Watauga County was not designed to accommodate future loads in those counties. The line west of Wilkesboro was originally proposed to be only six-inch steel pipe. In order to serve Ashe and Alleghany, Frontier increased the size of the line as far as Deep Gap to ten inches. The incremental cost of increasing this pipe size was $3,628,020. In addition, the negative net present value (NPV) of the transmission and distribution lines in Ashe County from Deep Gap was calculated to be $5,650,748. On December 22, 1999, Frontier filed its application for approval to use the proceeds of natural gas bond funds to finance the negative NPV of the project to serve Ashe and Alleghany Counties. Frontier later decided to divide up the project and filed an amended application for Ashe County only on May 3, 2000. The Commission issued its Order approving use of bond funds for service to Ashe County (including an allocated portion of the expanded ten-inch pipeline from Wilkesboro to Deep Gap) on June 29, 2000. Purcell testified that until this Order was issued, Frontier could not begin construction of the transmission line to Watauga County because it didn't know what size the line should be.

By the filing of the amended application on May 3, 2000, Frontier had sufficiently refined its design process/service work for the construction of its facilities in Watauga and Ashe Counties to indicate the facilities to be built. The amended application included detailed description of the project, including a detailed description of the physical facilities, an engineering study, a proposed construction schedule and project specifications. The Ashe County project involves laying 22 miles of ten-inch steel pipe along or near the right-of-way of US Highway 421 west from Wilkesboro to the intersection of US Highways 421 and 221 at Deep Gap. A six-inch steel pipeline will branch off at Deep Gap and proceed north for approximately 16 miles along US Highway 221 toward West Jefferson and Jefferson. The pipeline will supply gas to the district regulator station located near Jefferson, which will feed the six-inch plastic distribution pipeline that will serve as the backbone of the medium pressure system of West Jefferson and Jefferson. Frontier plans to construct two-inch distribution lines from the backbone system to supply gas to the residential, commercial and industrial customers in and around the targeted communities. Overall, the pipeline network will consist of 22 miles of ten-inch steel transmission pipeline from Wilkesboro to Deep Gap, 16 miles of six-inch steel pipeline from Deep Gap to city-gate at Jefferson, and 85 miles of two-inch, four-inch, and six-inch distribution pipeline from Deep Gap into Jefferson and West Jefferson. This same level of design process/service work was completed for Watauga County at around the same time. A six-inch steel line will run from Deep Gap to Boone, roughly following US Highway 421 for approximately 12 miles to Appalachian State University. Two-inch distribution pipe will also be laid along city streets in Boone to serve residential and small commercial customers.

NATURAL GAS - MISCELLANEOUS

As soon as the Commission's Order of June 29, 2000 was issued, Frontier began work. A total of 22.9 miles of ten-inch pipe was ordered on June 29, 2000. As of August 3, 2000, all ten-inch pipe had been ordered for the Wilkesboro to Deep Gap portion of the project, and all six-inch pipe necessary for the Deep Gap to Boone route and the Deep Gap to Jefferson route was already at Frontier's construction yard, ready for installation. During July, preliminary engineering for the Blue Ridge Parkway portion of the project in Watauga County was completed and permit applications were filed with Department of Environment and Natural Resources (DENR) and the Department of Transportation (DOT). Specific drawings had been prepared for the crossing of the Parkway School property. Specific engineering and profile drawings for a directional drill crossing of the New River were under development. Alignment sheet drawings for the entire section in Watauga County were also being developed. On July 17, 2000, a construction firm was engaged in an alliance arrangement to perform routing evaluations and final pipeline construction costs calculations for the entire project. As a result of their field constructability review, the routing was changed for a small portion of the pipeline from Deep Gap to Boone as of July 31. Tax maps and specific parcel maps for each private property easement in the vicinity of Parkway School in Watauga County were prepared in July to permit right-of-way acquisition for that segment of the pipeline.

Witness Purcell testified that since August 3, 2000, the storage yard and staging area for construction has been completed and put in operation. Design, drafting, and permitting work has continued. Easements have been acquired for the four-lane section of US Highway 421 between North Wilkesboro and the Blue Ridge Parkway. Five right-of-way agents and one manager are working on right-of-way acquisitions. They have identified 110 right-of-way parcels to be acquired and almost half of these parcels have been secured. In addition, Frontier has reached an agreement in principle for use of Blue Ridge Electric Membership Corporation's existing rights-of-ways throughout the service area. Frontier has signed a construction contract for the transmission pipeline to Ashe and Watauga Counties and three crews are operating. Over 38,000 feet of pipe has been laid. In Boone, construction efforts are being closely coordinated with another contractor that is expanding the Boone municipal water system. In late September 2000, Frontier was notified of a window of opportunity to lay its pipeline across part of the Blue Ridge Parkway in coordination with the reconstruction of the intersection of the Parkway with US Highway 421, and from October 16 to November 6, 2000, 2,418 feet of ten-inch pipe was laid from the east side of the Parkway. Approximately 1,600 feet of pipe is still necessary to cross the Parkway property; Frontier will be able to complete the laying of its pipeline in this area, connecting the western and eastern portions of its project, in August 2001.

Frontier has been engaged in ongoing discussions with Appalachian State University in Watauga County and Purcell testified that they were close to reaching an agreement whereby Frontier will be serving the university in September of 2001. Frontier has identified its target industrial customers in Ashe County and plans to be serving Gates Rubber and other customers along the transmission route by the end of 2001. Distribution lines to residential and small commercial customers in both counties will be constructed throughout 2002.

In its Statement of Position, the Public Staff agreed that Frontier has met the conditions in Rule R6-63(d)(i) and (iv) and is entitled to a grace period for Watauga and Ashe Counties.

The Commission concludes that Frontier had met the conditions of Rule R6-63(d)(i) and (iv) as to Watauga and Ashe Counties and was, in that sense, providing adequate service to the counties as of August 3, 2000. Frontier had completed a substantial amount of design work by that time, as evidenced by its May 3, 2000 amended application and by the testimony herein. It is clear from the evidence that this was not merely preliminary work, but rather that Frontier had made substantial commitments, invested significant time and capital, and was committed to the project. Further, it appears from the testimony as to events since August 3, 2000, that construction of Frontier's project for Watauga and Ashe Counties will be completed within the two-year grace period provided by Rule R6-63(d). No forfeiture will be ordered as to either Watauga or Ashe County.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

Frontier originally filed for natural gas bond funds to serve both Ashe and Alleghany Counties as a single, multi-phase project with lines from Deep Gap to Jefferson and then to Sparta. However, Frontier witness Purcell testified that in April 2000 Frontier decided to bifurcate the project and to proceed as to Ashe County alone. Frontier learned that it could not use its proposed route because the North Carolina DOT plans to widen portions of US Highway 221 between Jefferson and Sparta and the highway shoulders are too narrow to accommodate both the pipeline and the widening. Frontier intended to reconsider the route and to apply for bond funds for Alleghany County in fall 2000; however, pipeline construction costs have become extremely volatile, as evidenced by Frontier's experience in negotiating a contract for the Watauga and Ashe project where construction costs were significantly underestimated in Frontier's bond fund application. The difficulty in projecting costs is even greater when the project will not be built until more than a year in the future. Frontier therefore decided to defer its request for bond funds for Alleghany County until closer to the time for construction. It is therefore premature to finalize routes and project design. Because Frontier has neither acquired rights-of-way for Alleghany County, nor completed a substantial amount of the design process/service work, nor renewed its request for bond funds, Purcell conceded that Frontier has not met the conditions for a grace period as to Alleghany County. Purcell testified that Frontier would like to retain or be re-assigned its franchise for Alleghany County, consistent with its desire to serve the county someday; however Frontier did not want to impede efforts to bring natural gas to the county or in any way conflict with the best interests of the county.

The Public Staff position is that Frontier has not met the conditions of Rule R6-63(d) as to Alleghany County and that its exclusive franchise rights should be forfeited without prejudice.

The Commission concludes that Frontier has not met the conditions of Rule R6-63(d) as to Alleghany County, that Frontier was not providing adequate service to any portion of Alleghany County as of August 3, 2000, and that Frontier must forfeit its exclusive franchise rights to Alleghany County. This is without prejudice to the right to re-apply for a franchise for the county in the future.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Frontier witness Purcell testified that as of March 27, 2000, Frontier had completed construction of natural gas facilities into a substantial portion of Warren County and that although there were not yet any customers ready to use gas as of that date, Frontier had met all four of the conditions set forth in Commission Rule R6-63(d). He testified that on September 20, 1999, Frontier filed its application to use proceeds of natural gas bond funds to finance the negative net present value of a project to serve Warren County. An amended application was filed on November 16, 1999, indicating the facilities to be built and stating that rights-of-way for the first phase of the project had been purchased. The Commission approved the request on March 16, 2000. Meanwhile, construction had already begun. Frontier completed Phase I of the project by March 17, 2000, although there were no customers being served as of March 27, 2000. Phase I consists of approximately 15 miles of six-inch pipe starting from a Transco tap located near the North Carolina-Virginia border in Warren County south to Highway 158 and then to the Soul City/Madison area. The Phase I pipeline was gassed during the week of July 10-14, 2000. A Chesapeake cardboard manufacturing facility began receiving service on September 6, 2000.

Phase II -- extending transmission lines to the towns of Norlina and to the edge of Warrenton -- had been completed as of the time of the prefiled testimony. Frontier had installed approximately 2 1/2 miles of two-inch distribution lines in Norlina and was serving five residential meters and installing service lines to many more. A total of 26 3/4 miles of pipe had been laid and was in service in Warren County. Purcell testified that Phase III construction was underway and that construction of facilities will continue and additional distribution lines will be installed throughout 2001 and 2002. The Public Staff took no issue with Frontier as to Warren County.

The conditions for a grace period under Rule R6-63(d) require, as of the forfeiture date, a substantial amount of design work, or acquisition of rights-of-way, or the filing of an expansion fund application six months before, and the likelihood that service will be provided within two years. The Commission concludes that Frontier met the conditions of Rule R6-63(d) as to Warren County and was, in that sense, providing adequate service to Warren County as of March 27, 2000. Frontier had completed a substantial amount of design work and had acquired some rights-of-way; indeed, construction of Phase I had been completed as of March 27, 2000. Further, Frontier had applied for natural gas bond funds six months before.[1] Since March 27, 2000, Frontier has continued construction and begun serving customers. It already appears that Frontier will complete construction of facilities and begin providing service in Warren County within the two-year grace period provided by Rule R6-63(d) since it was already serving customers, including residential customers and the Chesapeake cardboard facility, and was continuing to install distribution lines at the time of the prefiled testimony. No forfeiture will be ordered as to Warren County.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier is not subject to forfeiture of its franchise for Wilkes, Surry, Yadkin or Warren Counties;

2. That as to Watauga and Ashe Counties, Frontier is hereby given until August 3, 2002, within which to complete construction of its proposed projects for these counties and to begin providing service, or be subject to a show cause proceeding on forfeiture of its exclusive franchise rights as provided in Rule R6-63(d); and

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[1]Although Rule R6-63(d) only mentions an application to use expansion funds, an application to use the proceeds of natural gas bond funds is substantially the same for purposes of the intent of the Rule. The natural gas bond legislation had not been enacted when Rule R6-63(d) was written.

3. That Frontier shall hereby forfeit its exclusive franchise rights to Alleghany County.

ISSUED BY ORDER OF THE COMMISSION.
This the_13th_ day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg031301.03

DOCKET NO. G-45, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Request by the Florian Companies for	)	
Approval of Natural Gas Master Metering and	)	ORDER APPROVING
Central Heating and Air Conditioning for the	)	MASTER METERING
Metropolitan Condominiums	)	

BY THE COMMISSION: On May 1, 2001, the Florian Companies (Florian) filed a letter requesting Commission approval, pursuant to G.S. 143-151.42, of natural gas master metering and central heating and air conditioning for The Metropolitan Condominiums project in downtown Raleigh. The project involves approximately 60 condominium units in a nine-story building containing approximately 122,000 square feet. Florian proposes to install a water source heat pump mechanical system consisting of a centralized fluid cooler and gas fired boilers that maintain the temperature of the condensing water loop. Each condominium unit would have its own heat pump unit(s) that extracts heat from or rejects heat to the condensing water loop. It is proposed that the fluid cooler and boiler will be served through common electric and gas meters; the heat pumps will be served through the meters of the individual units.

G.S. 143-151.42 provides in pertinent part:

> From and after September 1, 1977, in order that each occupant of an apartment or other individual dwelling unit may be responsible for his own conservation of electricity and gas, it shall be unlawful for any new residential building, as hereinafter defined, to be served by a master meter for electric service or natural gas service. Each individual dwelling unit shall have individual electric service and, if it has natural gas, individual natural gas service with a separate natural gas meter, which service and meters shall be in the name of the tenant or other occupant of, said apartment or other dwelling unit. No electric supplier or natural gas supplier, whether regulated public utility or municipal corporation or electric membership corporation supplying said utility service, shall connect any residential building for electric service or natural gas service through a master meter, and said electric or

> natural gas supplier shall serve each said apartment or dwelling unit by separate service and separate meter and shall bill and charge each individual occupant of said separate apartment or dwelling unit for said electric or natural gas service. . . . Provided, however, that any owner or builder of a multi-unit residential building who desires to provide central heat or air conditioning or central hot water from a central furnace, air conditioner or hot water heater which incorporates solar assistance or other designs which accomplish greater energy conservation than separate heat, hot water, or air conditioning for each dwelling unit, may apply to the North Carolina Utilities Commission for approval of said central heat, air conditioning or hot water system, which may include a central meter for electricity or gas used in said central system, and the Utilities Commission shall promptly consider said application and approve it for such central meters if energy is conserved by said design. (Emphasis added.)

The Public Staff presented this item at the June 25, 2001 Commission Conference. John Florian spoke on behalf of the request and answered questions. By its letter and presentation, Florian offered several reasons why master metering should be allowed. An analysis prepared by the project engineers shows that the proposed central heating and air conditioning system will result in energy savings of 1,584 Btu/ft^2-year or 2.9% compared to a completely individually metered electrical air-to-air heat pump system. In addition to the gas fired boilers, the heating system includes ventless fireplaces in the individual units. Natural gas service for cooking on ranges and grills will also be offered, but purchasers may use electricity for cooking if they prefer. Under the proposed arrangement, the condominium association will be responsible for utility services other than electricity. Condominium residents will pay for these services through their monthly fees, which will include a base amount for dues and an additional amount that will vary with the square footage of the unit but will not vary with utility usage from month to month. Further, Florian asserts that high-rise condominiums were not in existence when G.S. 143-151.42 was adopted, whereas there are such buildings today in other parts of the country and common HVAC systems and gas metering are typical design elements. Florian notes that these systems are accepted by both the Southern Building Code and the BOCA (Building Officials & Code Administrators) Building Code. Florian further asserts that, from a community perspective, projects like The Metropolitan conserve energy in a variety of ways: through reduced heat loss compared to smaller buildings or single family homes; by providing the opportunity for residents to walk to work or use mass transportation; by reducing the burden on roads and other infrastructure; and through diversification of fuel usage. From a business perspective, Florian asserts that the availability of gas cooking and fireplaces is critical to its ability to compete in the current marketplace. Florian also asserts that individually metering and piping these minimal gas services to individual units in mid- to high-rise buildings is impractical. According to the project engineer, the use of separate meters in The Metropolitan would require 16,000 feet of additional pipe. The amount of gas used for cooking is estimated to average 39.5 therms a year. At current rates, the average bill for cooking alone would be less than $45 a year, plus a $7.74 monthly facilities charge. Fireplaces, on the other hand, would be used only part of the year. Assuming that they are used five hours a week for five months, fireplaces would consume about 5.41 therms a month or 17.1 therms a year. Moreover, the engineering analysis indicates that the fireplaces are an efficient heating source that would reduce the boiler load.

The Public Staff stated that it has reviewed the engineering analysis submitted by Florian and concluded that the proposed water source heat pump mechanical system will result in energy conservation and therefore should be approved pursuant to the statute. However, the Public Staff stated that whether the statute permits master metering of the remainder of the gas service is less clear. A strict reading of G.S. 143-151.42 would suggest that master metering of natural gas service to the fireplaces, ranges, and grills is prohibited. However, the Public Staff stated that Florian's request raises legitimate questions as to whether such a prohibition is necessary in this case to comply with the intent of the statute, which is to encourage the conservation of energy by requiring occupants of individual dwelling units to be responsible for their own usage of electricity and natural gas. The Public Staff concluded that the Commission can reasonably conclude that all of the proposed gas service at The Metropolitan may be master metered.

The Commission concludes that Florian's request for approval of master metering should be granted. Florian has shown that its proposed water source heat pump system will result in energy conservation compared to a completely individually metered electrical air-to-air heat pump system and, therefore, the central heating and air conditioning system should be approved for master metering pursuant to the statute. Given the relationship of the gas fireplaces to the water source heat pump system and their effect on overall consumption, the fireplaces are arguably part of the central heating system. While gas ranges and grills are not part of any heating system, it appears doubtful that they would be offered apart from the boiler usage for the entire building. It also appears doubtful that separate metering of natural gas service for cooking alone, even if practical, would have any impact on energy conservation.

ISSUED BY ORDER OF THE COMMISSION
This the 5th day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg070501.01

Chair Sanford did not participate in this decision.
Commissioners Ervin and Joyner dissent.

DOCKET NO. G-45, SUB 0

COMMISSIONER SAM J. ERVIN, IV, DISSENTING.

I respectfully dissent from the Commission's conclusion that certain of the facilities proposed by the Florian Companies for The Metropolitan Condominiums do not violate North Carolina's statutory prohibition against master metering of electric and gas service. Although I do not doubt that construction of The Metropolitan Condominiums would provide many benefits to unit residents and to efforts to improve the quality of life in downtown Raleigh, I simply cannot agree with the Commission's conclusion that all of the natural gas service to be provided in The Metropolitan Condominiums in accordance with Florian's proposal is permissible under G.S. 143-151.42.

NATURAL GAS - MISCELLANEOUS

According to well-established principles of North Carolina law, the Commission has no authority except that granted by the General Assembly. State ex rel. Utilities Commission v. National Merchandising Corporation, 288 N.C. 715, 722, 220 S.E. 2d 304 (1975); State ex rel. Utilities Commission v. General Telephone Company of the Southeast, 281 N.C. 318, 336, 189 S.E. 2d 705 (1972). "*A fortiori*, the Commission has no authority to permit that which is forbidden by statute. . . ." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 464, 232 S.E. 2d 184 (1977). "When the language of a statute is clear and unambiguous, it must be given effect and its clear meaning may not be evaded by an administrative body or a court under the guise of construction." State ex rel. Utilities Commission v. Edmisten, 291 N.C. 451, 465, 232 S.E. 2d 184 (1977). See also: Peele v. Finch, 284 N.C. 375, 200 S.E. 2d 635 (1973); State ex. rel. Utilities Commission v. Lumbee River Electric Membership Corporation, 275 N.C. 250, 166 S.E. 2d 663 (1969). An analysis of the relevant facts and the plain language of G.S. 143-151.42 establishes that certain of the facilities proposed for The Metropolitan Condominiums by Florian are prohibited by North Carolina's master metering statute.

G.S. 143-151.42 states that "it shall be unlawful for any new residential building . . . to be served by a master meter for electric service or natural gas service" and that "[e]ach individual dwelling unit shall have individual electric service and, if it has natural gas, individual natural gas service with a separate natural gas meter, which service and meter shall be in the name of the tenant or other occupant of said apartment or dwelling unit." No party appears to contend that the natural gas service at issue in this proceeding would be individually metered. For that reason, the arrangements for providing natural gas service to The Metropolitan Condominiums as described by Florian are unlawful unless they fit within the parameters of the sole exception set out in G.S. 143-151.42, which allows master metering by "any owner or builder of a multi-unit residential building who desires to provide central heat or air conditioning or central hot water from a central furnace, air conditioner or hot water heater which incorporates solar assistance or other designs which accomplish greater energy conservation than separate heat, hot water, or air conditioning for each dwelling unit." I do not believe that this statutory language allows master metering of a considerable portion of the natural gas service at issue in this proceeding.

The only aspect of the natural gas service proposed for the Metropolitan Condominiums which was the subject of an engineering study was the use of natural gas to fire the boilers utilized in connection with the water source heat pump mechanical system. Although the record clearly establishes that each individual unit owner would be charged for the electricity used to operate the heat pump which serves his or her unit, the individual electric charges assessed against each unit owner would not result in unit-specific billing of the natural gas used to fire the boilers. On the contrary, the information which has been provided to the Commission indicates that the cost of the natural gas used to fire the boilers would be assessed against unit owners on the basis of the square footage of each unit rather than on the basis of the amount of gas usage attributable to each condominium. As a result, the arrangement proposed by Florian is not tantamount to individually metered gas service of the type required by G.S. 143-151.42.

In its effort to obtain Commission approval of the proposed facilities, Florian presented an engineering analysis that purports to show that the proposed central heating and cooling system would "accomplish greater energy conservation than separate heat, hot water, or air conditioning for each dwelling unit." Assuming for purposes of discussion that the system which Florian proposes to install in The Metropolitan Condominiums is a "central heating system" of the type contemplated by G.S. 143-151.42, Florian argues that the proposed facilities fall within the statutory "energy conservation" exception based upon an engineering study prepared by Progressive Design Collaborative, Ltd., which purports to show a 2.9% savings compared to individual air heat pump systems. I would be less than candid if I did not admit some concern about this study's relevance to the test required by the "energy conservation" exception. Florian admitted at the June 25, 2001, Commission conference that the Progressive Design study did not consider the possibility that a person occupying a unit served using the proposed heating and cooling arrangement would use more heating or cooling capacity than would be the case had the unit owner been required to pay his or her own individual energy costs. In other words, the study appears to ignore the very factor which resulted in the enactment of G.S. 143-151.42. On the other hand, I am not convinced that such an adjustment is required under the literal language of the "energy conservation" exception or that such an adjustment could be made with any reasonable degree of accuracy. As a result of the fact that the requirements of the "energy conservation" exception are met in the event that the applicant demonstrates the existence of "greater energy conservation" than separate heating and cooling facilities and that Florian's study demonstrates that the proposed facilities produce some small amount of energy savings compared to alternative facilities, I conclude that the Progressive Design study suffices to meet the requirements of the "energy conservation" exception to G.S. 143-151.42.

The same is not, however, true of the other natural gas facilities which Florian proposes to install at The Metropolitan Condominiums. The only arguments that Florian offered in support of its contention that the Commission should find the proposed gas fireplaces and gas ranges consistent with G.S. 143-151.42 are simply not compelling. Florian argues that we should approve the proposed gas fireplaces and ranges because the project as a whole will result in lower overall energy use than would accompany occupancy of a smaller building or a similar building located some distance from the center of town, because the gas usage required in connection with operating the fireplaces and ranges should be considered de minimis, and because the gas fireplaces are an efficient heating source that would reduce load on the building's heating and cooling system. I do not believe that these arguments suffice to bring the gas fireplaces and ranges within the scope of the "energy conservation" exception to G.S. 143-151.42. First, the information which Florian submitted in support of its request for approval of these facilities indicates that the fireplaces and ranges will consume approximately 38% of the natural gas consumed at The Metropolitan Condominiums. Even if the language of G.S. 143-151.42 allows some sort of de minimis consumption exception to the statutory prohibition against master metered utility service, I do not believe that the gas usage associated with the fireplaces and ranges can fairly be described as de minimis. Secondly, the availability of the "energy conservation" exception to the prohibition set out in G.S. 143-151.42 hinges upon a showing that the proposed facilities would result in "greater energy conservation" than individually metered facilities intended to provide equivalent service. The argument advanced by Florian and accepted by the Commission, which relies on the overall energy savings anticipated from the construction of The Metropolitan Condominiums at the proposed location compared to the construction of a similar number of housing units somewhere else, simply fails to address the criteria specified in the statute as a precondition for the availability of the "energy conservation" exception. Thirdly, I do not understand that the ability of unit owners to utilize heat from the gas fireplaces to displace heat from the central system, without more, suffices to show that those furnaces will produce energy savings compared to the available alternative. As I understand the record, the impact of utilizing these fireplaces was not incorporated into the Progressive Design study so that their impact on overall energy usage at The Metropolitan Condominiums has not been quantified. I believe that some minimal amount of quantification is a precondition for the application of the "energy conservation" exception. As a result, the evidence upon which the Commission relies to justify approving the gas fireplaces and gas ranges simply does not suffice to establish the availability of the "energy conservation" exception to the prohibition against master metering contained in G.S. 143-151.42.

The result reached by the Commission undoubtedly reflects its reluctance to disapprove a well-thought out condominium project on the basis of the provisions of a relatively old and rather technical piece of legislation. Although I share the Commission's belief that The Metropolitan Condominiums will provide a source of high-quality housing in central Raleigh, I simply do not believe that these benefits justify approving facilities which do not comply with the legislative policies enunciated in G.S. 143-151.42. The General Assembly has defined the circumstances under which master metering is and is not permissible; the Commission should not look past the plain language of legislative enactments in deciding whether the statutory criteria set out in that legislation have been met. In other words, I believe that the General Assembly has spoken with respect to the appropriateness of certain of the facilities at issue here and that the only avenue available to Florian for seeking relief from the provisions of G.S. 143-151.42 runs through the General Assembly rather than through the Commission. As a result, I respectfully dissent from the Commission's decision that certain of the facilities proposed by Florian for The Metropolitan Condominiums are not inconsistent with G.S. 143-151.42.

/s/ Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

DOCKET NO. G-45, SUB 0

COMMISSIONER LORINZO L. JOYNER, DISSENTING.

I also dissent from the Commission's decision to approve master metering of natural gas service on the facts presented by the request in this docket. I believe that the Commission must apply G.S. 143-151.42 as written by the General Assembly, and I do not believe that the statute permits the master metering of natural gas service as proposed by Florian. I agree with the reasoning set forth in the dissent of Commissioner Ervin, and I join in his dissent.

/s/ Lorinzo L. Joyner
Commissioner Lorinzo L. Joyner

DOCKET NO. G-3, SUB 241

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of NUI Corporation d/b/a NUI North Carolina Gas, for Approval of Gas Costs and Gas Purchasing Policies for the Period May 1, 2000 through April 30, 2001.	)))))	ORDER ON ANNUAL REVIEW OF GAS COSTS

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on October 9, 2001.

BEFORE: Commissioner James Y. Kerr, II, Presiding; Commissioner Robert V. Owens Jr.; and Commissioner J. Richard Conder.

APPEARANCES:

For NUI North Carolina Gas:

James H. Jeffries IV, Nelson, Mullins, Riley & Scarborough, LLP, Bank of America Corporate Center, Suite 3350, 100 North Tryon Street, Charlotte, North Carolina 28202-4000

For the Public Staff:

Gina C. Holt, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Carolina Utility Customers Association, Inc.:

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

For the Attorney General's Office:

Margaret A. Force, Assistant Attorney General, N.C. Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On June 29, 2001, NUI Corporation d/b/a NUI North Carolina Gas (NUI NC Gas or the Company), filed testimony and exhibits of Alan Virostek, Accounting Manager with NUI Corporation, and Thomas E. Smith, Director of Energy Planning with NUI Corporation, relating to the annual review of its gas costs under G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) for the period May 1, 2000 through April 30, 2001.

On July 6, 2001, the Commission issued an Order Scheduling Hearing, Requiring Filing of Testimony, Discovery Deadlines and Requiring Public Notice. This Order established a hearing date of Tuesday, September 4, 2001, set dates for pre-filed testimony and intervention, and required NUI NC Gas to give notice to its customers of the hearing on this matter.

On July 31, 2001, the Carolina Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene in this proceeding, which the Commission granted by Order dated August 8, 2001.

On August 15, 2001, the Attorney General of North Carolina filed a notice of intervention. The intervention and participation of the Attorney General was recognized pursuant to G.S. 62-20.

On August 20, 2001, the Public Staff filed a motion for extension of time. The order granting the motion for extension of time and rescheduling hearing was issued on August 21, 2001. The order scheduled the hearing in this docket for September 4, 2001, for the taking of testimony of public witnesses, and the hearing for the testimony of expert witnesses was rescheduled to Monday, September 17, 2001, at 2:00 p.m.

NUI North Carolina Gas filed a motion to continue hearing on August 31, 2001, and the Commission issued an order granting motion to continue hearing for the testimony of expert witnesses to Tuesday, October 9, 2001, at 10:00 a.m.

The Public Staff filed the direct joint testimony of Jan A. Larsen, Utilities Engineer of its Natural Gas Division, and James G. Hoard, Assistant Director of its Accounting Division, on September 28, 2001.

On October 5, 2001, NUI NC Gas filed the rebuttal testimony of Thomas Smith. No other parties filed testimony.

On October 9, the matter came on for hearing as rescheduled in Raleigh. No public witnesses appeared. The prefiled testimony and exhibits of Alan Virostek were admitted into the record without his appearance on the stand. The Company offered the testimony of Thomas E. Smith and the Public Staff offered the panel testimony of Jan A. Larsen and James G. Hoard.

On October 12, 2001, NUI NC Gas filed a late-filed exhibit as instructed by the Commission at the evidentiary hearing.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. NUI NC Gas is an operating division of NUI Corporation, which is a corporation organized under the laws of the state of New Jersey and duly registered to do business in North Carolina.

2. NUI NC Gas is engaged in the business of transporting, distributing, and selling natural gas in a franchised area that consists of all of Rockingham County and part of Stokes County in the northern piedmont region of North Carolina.

3. NUI NC Gas is a public utility as defined by G.S. 62-3(23) and is subject to the jurisdiction of this Commission and is lawfully before this Commission upon its application for annual review of gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

4. NUI NC Gas' testimony, exhibits, affidavits of publication and published hearing notices are in compliance with the provisions of the North Carolina General Statutes and the Rules and Regulations of this Commission.

5. The period for review of gas costs in this proceeding is the 12 months ended April 30, 2001.

6. During the period of review, the Company incurred total gas costs of $17,548,409 composed of fixed gas costs of $2,057,439, commodity gas costs of $12,880,767, and other gas costs of $2,610,203.

7. As of April 30, 2001, there was a credit balance of $431,068 in the All Customers Deferred Account. The balance in the Sales Customers Only Deferred Account is to be recalculated to reflect the findings in the body of this Order.

8. NUI NC Gas' gas purchasing policies are prudent and NUI NC Gas' gas costs during the review period were prudently incurred, and after incorporating adjustments by the Public Staff and the Commission, properly accounted for.

9. NUI NC Gas should be permitted to recover 100 percent of its prudently incurred gas costs.

10. NUI NC Gas currently has in place a temporary increment of $0.00137/therm relating to sales only customers and the following temporary decrements relating to all customers: Rate Schedule 101 (Residential) - ($0.01039/therm); Rate Schedule 102 (Small General) - ($0.01016/therm); Rate Schedule 104 (Large General) - ($0.00565/therm); Rate Schedule 105 (Interruptible) - ($0.00299/therm).

11. Based upon the balances of the Company's adjusted deferred accounts at April 30, 2001, the current temporary decrements in NUI NC Gas' rates should be discontinued and temporary decrements should be implemented for all customers as follows: Rate Schedule 101 (Residential) - ($0.01919/therm); Rate Schedule 102 (Small General) - ($0.01876/therm); Rate

Schedule 104 (Large General) - ($0.01043/therm); Rate Schedule 105 (Interruptible) - ($0.00552/therm). A temporary decrement should be implemented for sales only customers based on the decrement calculated by the Public Staff, as adjusted by the findings in the body of this Order.

12. The Company should file a contract setting forth the terms and conditions for gas procurement activities performed by NUI affiliates and operating divisions on behalf of NUI NC Gas.

13. The Company should file with the Commission, within 30 days of execution, a redacted copy of all negotiated sales and transportation contracts of more than one month but less than or equal to one year. Such contracts shall be subject to review in the Company's next annual prudence review proceeding. Contracts of more than one year shall be subject to Commission approval prior to becoming effective.

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

These findings of fact are jurisdictional, procedural, and informational in nature and are not contested by any party. They are supported by the petition, the testimony and exhibits of the various witnesses, the records of the Commission and the Affidavits of Publication filed with the Commission in this proceeding.

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

The evidence for these findings of fact is contained in the testimony of NUI NC Gas witnesses Smith and Virostek and the Public Staff Panel, and the findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4(c), requires that NUI NC Gas submit to the Commission specified information and data for a historical 12-month test 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) requires the filing of weather-normalized sales volume data, work papers, and direct testimony and exhibits supporting the information filed.

An examination of the testimony and exhibits of witnesses Smith and Virostek confirms that the Company complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k). The Public Staff's joint testimony also provides that the Company filed its gas cost information in accordance with G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

The review period for this proceeding is established by Commission Rule R1-17. The review period designated for NUI NC Gas under Rule R1-17(k)(6)(a) in this proceeding is the 12-month period ending April 30, 2001.

The Commission concludes that NUI NC Gas has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6) for the 12-month review period ending April 30, 2001.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is contained in the testimony of the Public Staff Panel and Company Witness Virostek. The Public Staff Panel testified that the Company recorded gas costs of $17,548,409, composed of fixed gas costs of $2,057,439, commodity gas costs of $12,880,767, and other gas costs of $2,610,203. Public Staff witness Hoard testified that the Company agreed with these amounts, which were different than the amounts initially filed by the Company.

Based on the foregoing, the Commission concludes that the above-stated gas cost amounts are appropriate for use herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is contained in the testimony of the Public Staff Panel and Company witnesses Virostek and Smith. Company witness Virostek reflected April 30, 2001, deferred account balances of $431,068 owed customers in the All Customers Deferred Account and $201,042 owed to customers in the Sales Customers Only Deferred Account. The Public Staff agreed with the amount reflected in the All Customers Deferred Account, but recommended two adjustments to the Company's Sales Customers Only Deferred Account of $266,991, which increases the amount owed customers to $468,033. Company witness Smith agreed to both of these adjustments in his rebuttal testimony.

The first adjustment reverses a $123,009 prior period inventory adjustment recorded by the Company in May 2000. According to the Public Staff Panel, the Company determined that the general ledger and the subsidiary ledger reflected different recorded values for the gas contained in the General Storage Service (GSS) and Washington Storage Service (WSS) inventories. In May 2000, the Company made an accounting adjustment, which was recorded on the general ledger to bring it into agreement with the correct subsidiary ledger. At the same time, the Company recorded an accounting entry in the Sales Customers Only Deferred Account. Because activity previously recorded in the deferred account was based on the correct subsidiary records, the Public Staff testified that an accounting entry to the deferred account should not have been recorded and, therefore, this $123,009 accounting entry, plus accrued interest, should be reversed. The Company stated that it did not contest this adjustment. The Commission agrees with the adjustment made by the Public Staff.

The second adjustment reflects the impact of emptying WSS prior to its transfer from NUI NC Gas to an unregulated affiliate, NUI Energy Brokers (NUI EB). During the period under review, NUI Corporation decided to transfer NUI NC Gas' WSS storage contract with Transco from NUI NC Gas to NUI EB. The transfer was effective October 1, 2000 and, at that time, NUI EB began paying the demand charges associated with the WSS contract. NUI NC Gas witness Smith stated that it was the Company's intention to empty WSS prior to October 1, 2000, and as a result, the 2000 - 2001 winter planning guide (for gas supply and capacity requirements) did not provide for WSS utilization. However, the Company failed to empty its WSS capacity prior to its transfer and, at the date of transfer, NUI NG Gas' WSS had 82,433 dekatherms (dts) of gas in storage at an average unit price of $2.6656/dt and a total book value of $219,733 (because fuel gas must be given to Transco, the actual volume available was 79,234.6 dekatherms, with an adjusted price of $2.7109/dt).

Furthermore, NUI EB did not withdraw the gas after the transfer. Mr. Smith stated that, "NUI Energy Brokers was operating under the assumption that there was no gas in that particular WSS contract when it was turned over to them." As natural gas prices increased last winter, ratepayers did not receive any benefit from the relatively low-cost WSS gas to which NUI had access.

NUI NC Gas witness Smith discussed the WSS contract and why it was transferred. He testified that both NUI NC Gas and "Elizabethtown" had WSS contracts and ". . . WSS has been pooled for a number of years." He explained that ". . . the Elizabethtown WSS and North Carolina WSS has been pooled and allocated among all of the utility divisions of NUI. And the fixed cost of those contracts are recovered from each of the utility divisions in proportion to the firm annual requirements of each division." He confirmed that WSS was allocated as needed to the various operating divisions of NUI Corporation. He was then asked to explain why--if WSS capacity was already being pooled and allocated--it was decided to transfer the WSS contracts to NUI EB. He responded that, ". . . the company did an evaluation of WSS about, maybe a little over a year and a half ago, to determine whether or not continuing to rely on WSS as a backup to supply was actually cost effective to the ratepayer." He contended that, overall, ". . . we were paying more for the WSS [than] . . . the value we were getting out of it." He added that, ". . . the markets for natural gas had become much more robust and/or other methods by which you could get gas supply in a short curtailment period, we determined that we really didn't require WSS as a back up to the utility needs."

With regard to the value of WSS to NUI NC Gas' ratepayers and decision to transfer the WSS contract, Public Staff witness Larsen explained that the demand charges were compared with the differences in purchasing gas in the summer and injecting it into WSS and taking the gas out in the winter when gas prices were typically higher. He testified, ". . . whether it was cost effective to continue to have this service . . . just depends what winter season it is. This last winter, it would have been good to have it because prices are very high. You would have cheaper gas in storage you could pull out and have cheaper gas in the winter." Mr. Larsen repeated that, "it depends on the weather," adding, "If it's very cold, much colder than normal, prices go up . . . it will be beneficial." However, Mr. Larsen stated that, over the last seven years, WSS was not cost-effective.

Because NUI failed to utilize the low-cost gas available, Public Staff felt an adjustment to ratepayers was warranted. The Public Staff Panel testified that the size of the adjustment would vary significantly, depending on the gas prices used in the computation. The Public Staff considered three pricing alternatives: (1) use the gas prices experienced during the coldest part of the winter season, (2) use the prices at the October 1, 2000, transfer date and (3) use the prices over the "summer season" during which NUI had proposed to empty the storage.

Public Staff first considered calculating the difference between the cost of the stored gas and the potential market price by using the peak January prices. Public Staff rejected this approach because it believed that the long-term decision to eliminate WSS from utility operations was "fundamentally prudent." Public Staff also rejected the use of the October market price because it was NUI NC Gas' stated intent to empty WSS prior to the transfer. Public Staff recommended the third option of calculating the difference as if NUI had emptied WSS storage during the 2000 summer season as the Company intended (May through September at a steady rate). It assumed one-fifth of the total WSS volume of 79,234.6 dt (82,433 dt, adjusted for fuel retention) was withdrawn from

WSS each month between May and September 2000 and replaced gas purchased by the Company under its Transco FS contract. The Public Staff computed an adjustment of $122,013 that gave ratepayers the benefit of emptying WSS gas into the Company's system during the 2000 summer season, as intended, plus accrued interest at an annual rate of 10%.

The Company did not contest the Public Staff's WSS adjustment.

CUCA disagreed with the pricing alternative chosen by the Public Staff and agreed upon by the Company. CUCA noted that the settlement proposal between the Public Staff and NUI NC Gas--to credit ratepayers with $122,013--is derived from Public Staff's application of a non-binding gas transfer plan with which NUI Corporation failed to comply. The plan to transfer WSS was not binding; if gas prices had gone down, NUI Corporation could have decided not to proceed with the transfer. Also, ratepayers were required to pay the fixed costs until October 1, 2000.

CUCA contends that the Commission should set the market price of the transferred storage gas as of October 1, 2000 rather than at a blended price created during the period May through September 2000. Using the Transco FS price for October 2000, CUCA calculates that NUI NC Gas should credit to ratepayers $223,442, plus interest at the rate of 10% per annum for November 2000 through December 2001. To make this calculation, CUCA obtained the actual Transco FS price for October 2000 by using NUI NC Gas' deferred account report for November. To generate Transco FS data for May through September, the Public Staff included data from NUI NC Gas' monthly deferred account reports in Public Staff Panel Exhibit 1, Schedule 2. The Transco FS prices for May through September are clearly in the record. In its brief, CUCA argues that "To the extent necessary, the Commission is entitled pursuant to G.S. 62-65(b) to take judicial notice of the deferred account reports filed by NUI itself in Docket No. G-3, Sub 229." CUCA attached the relevant page from the November report to its brief.

NUI NC Gas responded to CUCA's suggestion that the WSS volumes be priced at the October 1, 2000 index price by stating that that ignores the contractual and physical reality since NUI NC Gas was only entitled to withdraw a maximum of 1,929 dekatherms of gas per day. The Commission notes that, at that rate, the remaining gas in storage would have been withdrawn in a little over forty days.

The Public Staff's use of a hypothetical withdrawal schedule puts the ratepayers back to where they would have been financially if the Company had followed its plan. But the simple fact is that NUI NC Gas failed to follow its own plan and, had the price gone down rather than up, was not even under a contractual obligation to follow through with the transfer. NUI NC Gas' handling of almost 79,235 dekatherms of relatively low-priced gas in a period in which the commodity cost of gas skyrocketed can only be described as negligent. After careful consideration of this issue, the Commission concludes that, since NUI NC Gas failed to withdraw the WSS storage gas as planned, but did transfer the demand charges on October 1, 2000, the forgotten gas should be valued at the price on the day in which the transfer of the WSS contract occurred--October 1, 2000. The Commission further concludes that the procedure followed by the Public Staff to calculate its adjustment--the use of the Transco FS rate (with the October price), with accrued interest at an annual rate of 10%--should be used to recalculate the adjustment.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8 and 9

The evidence for these findings of fact is found in the testimony of Company witness Smith and the Public Staff Panel.

Company witness Smith testified that NUI NC Gas' gas purchasing policy was designed to meet four primary objectives: (1) maintain secure supplies for firm customers; (2) diversify supply sources to ensure reliability; (3) obtain the lowest reasonable cost; and (4) enhance flexibility. Company witness Smith also testified that NUI NC Gas' gas costs during the review period were consistent with this policy and were prudent. During the period of review, NUI NC Gas' gas supplies were provided primarily through long-term firm supply contracts and pricing was tied to a spot market index.

The Public Staff Panelists testified that they believed that NUI NC Gas' gas costs were prudently incurred and, after considering the Public Staff's adjustments, properly accounted for. In reaching the decisions, the panelists testified that they reviewed the Company's monthly deferred account reports, monthly financial and operating reports, gas supply, pipeline transportation and storage contracts, as well as responses to the Public Staff's data requests. The Public Staff also testified that it had numerous discussions with Company personnel regarding gas procurement and system planning and dispatching.

The Commission believes that the Company's gas costs were prudently incurred, and after incorporating the Public Staff's adjustments, properly accounted for, and should be approved.

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

The evidence for these findings of fact is found in the testimony of Company witness Smith and the Public Staff Panel.

Company witness Smith testified that the existing deferred account temporary decrements established by the Commission in Docket No. G-3, Sub 230 were: (1) an increment of $0.00137/therm relating to the Sales Customers Only Deferred Account: and (2) decrements of: Rate Schedule 101 (Residential) - ($0.01039/therm); Rate Schedule 102 (Small General) - ($0.01016/therm); Rate Schedule 104 (Large General) - ($0.00565/therm); and Rate Schedule 105 (Interruptible) - ($0.00299/therm) relating to the All Customers Deferred Account. This testimony is undisputed and is consistent with the Commission's November 6, 2000, Order on Annual Review of Gas Costs in Docket No. G-3, Sub 230.

The Public Staff Panel testified that based on the Company's deferred account balances at April 30, 2001, as adjusted by the Public Staff, new temporary decrements for all customers should be implemented as follows: Rate Schedule 101 (Residential) - ($0.01919/therm); Rate Schedule 102 (Small General) - ($0.01876)/therm); Rate Schedule 104 (Large General) - ($0.01043/therm); Rate Schedule 105 (Interruptible) - ($0.00552/dt). Additionally, the existing temporary increment and decrements should be discontinued and a temporary decrement of ($0.01253)/therm for sales only customers should be instituted. Company witness Smith agreed with the decrements proposed by the Public Staff. The Commission concludes that the Public Staff's temporary decrements for all customers should be implemented and the Public Staff's temporary decrement of ($0.01253/therm) for sales only customers should be recalculated to reflect the change the Commission required in the adjustment arising from NUI NC Gas' failure to withdraw gas before transferring the WSS contract.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is found in the testimony of the Public Staff Panel and Company witness Smith. The Public Staff Panel testified that various NUI affiliates and operating divisions perform gas procurement activities on behalf of NUI NC Gas; NUI NC Gas is allocated a portion of the costs for certain gas supply and storage contracts; and gas is regularly bought and sold among the NUI companies and divisions. The terms and conditions for assigning responsibilities, allocating costs, determining the prices applicable to intercompany transactions, and the payment of compensation have not been memorialized in a contract, thus hindering the ability of the Commission and Public Staff to properly oversee the Company's operations. The Panel testified that the Company is due to file shortly, pursuant to the Commission's order in Docket No. G-3, Sub 232, a revised cost allocation manual and recommended that the Commission reinforce its requirement that the Company file a revised cost allocation manual. In addition, the Panel recommended that the Commission require NUI NC Gas to file a contract encompassing the issues described above, within 90 days of the Commission's order in this proceeding and require that the contract be subject to approval pursuant to G.S. 62-153.

Company witness Smith testified that he did not have any objections to the Public Staff's recommendation provided the contract allows the flexibility needed to take advantage of what is available in the market place on a timely basis. Public Staff witness Hoard testified that the Public Staff envisioned a broad agreement that addresses how gas procurement supply issues will be handled within the Company.

The Commission concludes that the Company should file a contract with the Commission that sets forth the broad terms and conditions for gas procurement activities performed by NUI affiliates and operating divisions on behalf of NUI NC Gas.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The Public Staff Panel testified that in previous annual gas cost review proceedings involving two other LDCs, Public Service Company of North Carolina, Inc., and North Carolina Natural Gas Corporation, the Commission ordered the LDCs to file certain multi-month negotiated contracts with the Commission. In order to be consistent, the Public Staff Panel recommended that the Commission adopt similar procedures on a prospective basis for NUI NC Gas. Specifically, the Public Staff Panel recommended that the Company file with the Commission a redacted copy of all negotiated sales and transportation contracts of more than one month but less than or equal to one year, within 30 days of execution. The Public Staff Panel did not recommend pre-approval of these contracts, but that such contracts be on file and subject to review in the following annual prudence review. Also in the interest of being consistent, the Public Staff recommended that negotiated contracts of more than one year should be filed with the Commission and subject to prior Commission approval before becoming effective. The Company did not oppose the Public Staff's recommendations. The Commission concludes that the recommendations of the Public Staff should be adopted.

IT IS, THEREFORE, ORDERED as follows:

1. That the $2,057,439 in fixed gas costs, $12,880,767 in commodity gas costs and $2,610,203 in other gas costs incurred by NUI NC Gas during the period of review be, and they hereby are, determined to be prudently incurred.

2. That NUI NC Gas' accounting for all such gas costs, as adjusted by the Public Staff and the Commission and reflected in this Order be, and the same hereby is approved.

3. That NUI NC Gas be, and it hereby is, authorized to recover 100 percent of its prudently incurred gas costs during the period of review.

4. That the adjustment to the Sales Customers Only Deferred Account proposed by the Public Staff to reflect NUI NC Gas' failure to withdraw gas available under the WSS contract before transferring that contract to NUI Energy Brokers shall be recalculated pursuant to the findings in the body of this Order. The Commission directs the parties to work together jointly to recalculate the adjustment and file it with the Commission as soon as possible and no later than ten days from the date of this Order.

5. That the existing temporary increment and decrements contained in NUI NC Gas' rates from the Commission's November 6, 2000, Order on Annual Review of Gas Costs in Docket No. G-3, Sub 230, should be discontinued and NUI NC Gas shall implement in its next billing cycle after the date of this Order the following temporary decrements for all customers: Rate Schedule 101 (Residential) - ($0.01919/therm); Rate Schedule 102 (Small General) - ($0.01876)/therm); Rate Schedule 104 (Large General) - ($0.01043/therm); Rate Schedule 105 (Interruptible) - ($0.00552/dt). Furthermore, a new temporary decrement for sales only customers calculated pursuant to this Order shall be implemented.

6. That the Company shall file a contract with the Commission that sets forth the broad terms and conditions for gas procurement activities performed by NUI affiliates and operating divisions on behalf of NUI NC Gas.

7. That the Company shall file with the Commission a redacted copy of all negotiated sales and transportation contracts of more than one month but less than or equal to one year, within 30 days of execution. Such contracts shall be subject to review in the Company's next annual prudence review proceeding. Contracts of more than one year shall be subject to Commission approval prior to becoming effective.

8. That NUI NC Gas shall give notice to all of its customers of the changes in rates approved in this order by appropriate bill inserts beginning with the first billing cycle that includes the changes in rates approved herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2001

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

wg121801.01

DOCKET NO. G-5, SUB 421

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, 2001, 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 J. Richard Conder and James Y. Kerr, II

APPEARANCES:

For Public Service Company of North Carolina, Inc.:

Allyson K. Duncan, Kilpatrick Stockton LLP, 3737 Glenwood Avenue, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Gina C. Holt, Staff Attorney, Public Staff – North Carolina Utilities Commission, P. O. Box 29520, Raleigh, North Carolina 27626-0520

For the Attorney General:

Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, P. O. Box 629, Raleigh, North Carolina 27699-4326

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, PC, Suite 1735, 934 Fayetteville Street Mall, Raleigh, North Carolina 27601

BY THE COMMISSION: On June 1, 2001, Public Service Company of North Carolina, Inc. (PSNC or Company) filed the direct testimony and exhibits of Melinda C. Russell, Manager – Gas Supply, and Pamela A. Hall, Regulatory and Gas Cost Analyst, 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 12, 2001, the North Carolina Utilities Commission (the Commission) issued an Order scheduling a hearing on August 14, 2001, setting other procedural deadlines, establishing discovery guidelines and requiring public notice.

On June 21, 2001, the Carolina Utility Customers Association (CUCA) filed a petition to intervene, which the Commission granted on June 26, 2001. On July 5, 2001, the Attorney General filed a notice of intervention.

On July 30, 2001, the Public Staff filed the testimony and exhibits of Julie G. Perry, Supervisor of the Natural Gas Section in the Accounting Division, and Jeffrey L. Davis, Director of the Natural Gas Division.

On August 14, 2001, the matter came on for public hearing. PSNC witnesses Russell, Hall and William C. Williams, and Public Staff witnesses Perry and Davis, were the only witnesses to present testimony.

Based on the testimony, schedules and 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 370,000 winter-peak customers within a certificated service area consisting of all or parts of twenty-eight (28) counties in central and western North Carolina as designated in PSNC's certificates of public convenience and necessity issued by this Commission.

2. PSNC is engaged in providing natural gas utility 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 ending March 31, 2001.

5. As of March 31, 2001, the deferred account balance for Sales-Only customers was $9,838,122 owed to PSNC from its customers, and the All-Customers Deferred Account balance was $13,211,253 owed to PSNC's customers.

6. The Public Staff took no exceptions to PSNC's accounting for gas costs and recoveries during the review period.

7. PSNC has properly accounted for its gas costs and collections from customers during the review period.

8. PSNC has adopted a gas supply policy, which it refers to as a "best cost supply strategy." This gas supply policy is based upon three primary criteria: supply security, operational flexibility, and cost of gas. The best cost of gas under this strategy will not necessarily be the lowest cost.

9. For the review period, PSNC had approximately 235,000 dekatherms (dt) per day under long-term contracts with at least six major producers and three interstate marketing affiliates. All of these contracts have provisions that ensure that the pricing remains market-sensitive.

10. PSNC has made prudent gas purchasing decisions, and all of the gas costs incurred during this review period were prudently incurred.

11. PSNC should be permitted to recover 100 percent of its prudently incurred gas costs.

12. PSNC's agreements to engage in certain transactions with SCANA Energy Marketing, Inc. (SEMI) are in compliance with the Code of Conduct imposed by the Commission in Docket Nos. G-5, Sub 400 and G-43, and the costs incurred thereunder during the review period were prudently incurred.

13. All amendments to PSNC's buy-sell agreement with PSNC Production should be filed pursuant to G.S. 62-153(a).

14. Pursuant to PSNC's request, the rate decrement of $.00614 per therm approved associated with the Sales-Only Deferred Account is discontinued. As recommended by the Public Staff, and agreed to by PSNC during the hearing, the All-Customers Deferred Account balance of $13,211,253 will be refunded to each rate schedule in accordance with the calculations contained in Davis Exhibit A.

15. The $1.4 million credit to PSNC customers for "True-up of unaccounted for and company use gas" is calculated in accordance with the level set in Commission Docket No. G-5, Sub 386, and is appropriately credited to all customers.

16. PSNC should be allowed to credit and recover the amounts reflected as Rider F activity in the All-Customers Deferred Account for the review period.

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

These findings of fact 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, schedules and exhibits filed by the witnesses for PSNC and the Public Staff.

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

The evidence for these findings of fact is contained in the testimony of PSNC witnesses Russell and Hall and Public Staff witnesses Perry and Davis, and the findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

The relevant statute, G.S. 62-133.4(c), requires PSNC to submit to the Commission specified information and data for a historical 12-month test 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 weather-normalized sales volume data, work papers, and direct testimony and exhibits supporting the information filed.

Commission Rule R1-17(k)(6) requires PSNC to submit the information specified to the Commission based on a 12-month test period ending March 31. An examination of the testimony of PSNC witness Hall confirms, and it is undisputed that, PSNC has complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6). PSNC witness Hall further testified that PSNC filed with the Commission, and submitted to the Public Staff, complete monthly accountings of the computations required by Commission Rule R1-17(k)(5)(c) throughout the review period. Public Staff witness Perry stated that PSNC has properly accounted for its gas costs during the review period. The Public Staff has not taken issue with any of these filings, and they are found to be in conformity with the rules.

The Commission concludes that PSNC has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the 12-month review period ending March 31, 2001.

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

The evidence supporting these findings of fact is found in the testimony of PSNC witness Hall and Public Staff witness Perry.

PSNC witness Hall testified that the balance in PSNC's Sales-Only Deferred Account as of March 31, 2001, was $9,838,122 owed to PSNC from its customers. Ms. Hall summarized the activity in the Sales-Only Deferred Account during the twelve months ending March 31, 2001, as follows:

Beginning balance, April 1, 2000	$(2,198,378)
Commodity cost undercollections	3,082,340
Negotiated margin losses	5,945,181
G-5, Sub 414 decrement	2,358,937
Accrued interest	650,042
Ending balance	$ 9,838,122

The balance in the All-Customers Deferred Account as of March 31, 2001, was $13,211,253 owed to PSNC's customers. Ms. Hall summarized the activity in the All-Customers Deferred Account for the twelve months ending March 31, 2001, as follows:

Beginning balance, April 1, 2000	$ 2,337,856
Commodity cost overcollections	(3,552,457)
Demand cost overcollections	(4,623,554)
True-up of unaccounted-for and company-use gas	(1,431,186)
Buy/sell credits	(957,717)
Capacity release credits	(2,537,478)
Other secondary market transaction credits	(2,785,231)
Rider F activity	23,793
Supplier refund credit	(7,040)
Accrued interest	321,761
Ending balance, March 31, 2001	$(13,211,253)

Public Staff witness Perry testified that the Public Staff examined PSNC's accounting for gas costs during the review period ending March 31, 2001, and concluded that PSNC had properly accounted for its gas costs during this review period.

Based upon the testimony, exhibits, and schedules of the witnesses, the monthly filings by PSNC as required by Commission Rule R1-17(k)(5)(c), and the data set forth above, the Commission concludes that PSNC has properly accounted for its gas costs during the review period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting these findings of fact is found in the testimony of PSNC witness Russell and Public Staff witness Davis.

PSNC witness Russell testified that the most appropriate description of PSNC's gas supply policy is a "best cost" supply strategy. This gas supply strategy is based upon three primary criteria: supply security, operational flexibility and the cost of gas.

PSNC witness Russell testified that the first and foremost criterion in its "best cost" supply strategy is security of gas supply. To maintain the necessary supply security for all of its firm customers, PSNC has supply contracts with delivery guarantees and storage service contracts with deliverability rights that provide total gas deliveries to PSNC to facilitate full use of PSNC's firm interstate pipeline transportation capacity. PSNC's rationale for this requirement is that, during design peak conditions, its interruptible customers would most likely be curtailed. PSNC has executed long-term supply agreements and supplemental short-term supply agreements with a variety of suppliers, including producers, interstate pipeline marketing affiliates and independent marketers. By developing a diversified portfolio of capable long-term and short-term suppliers, PSNC believes that it has increased the security of its gas supplies. PSNC evaluates potential suppliers on the basis of a variety of factors, including past performance and gas deliverability capability.

PSNC witness Russell testified that the second primary criterion in its "best cost" gas supply strategy is maintaining the necessary operational flexibility in PSNC's gas supply portfolio. Operational flexibility is necessary because of the daily changes in PSNC's market requirements resulting from the unpredictable nature of the weather, the operating schedules of industrial customers, and their ability to switch to an alternate fuel. While each of PSNC's gas supply agreements has different purchase commitments and swing capabilities (including, for example, the ability to adjust the volumes purchased within the contract volume), the gas supply portfolio as a whole must be capable of handling the monthly, daily and hourly changes mandated by market conditions.

PSNC witness Russell testified that the third primary criterion in its "best cost" gas supply strategy is acquiring the most cost effective supplies of natural gas available for its customers while maintaining the necessary security and flexibility to serve their needs. In response to questions from Commissioner Ervin, PSNC witness Russell testified that "best cost" is not necessarily least cost. Although PSNC strives to pay the lowest price possible, that goal yields to the need to preserve the reliability of its supply and the flexibility to meet rapidly and dramatically varying market needs.

In response to questions from the Attorney General, PSNC witness Russell testified that PSNC did not engage in hedging transactions to lock in gas supply costs under fixed price contractual provisions during the review period. She stated that PSNC will await Commission action on hedging prior to undertaking that type of procedure in gas purchasing. Ms. Russell testified that PSNC's management of its benchmark cost of gas mitigates price volatility. PSNC's benchmark increased at a much slower pace than did the market price of gas at the city gate during the review period. For example, in comparing June of 2000 to January of 2001, the market price at the city gate increased by approximately $5.75, whereas the commodity benchmark price of gas rose by only $3.40.

PSNC witness Russell further testified that the use of storage gas--withdrawing lower priced gas in times of price spikes--is another method utilized by PSNC to mitigate price volatility. Although storage is also a tool for addressing peak demand, Ms. Russell testified that PSNC's use of storage to stabilize prices does not necessarily impede its ability to meet its peaks as well. Ms. Russell testified that minimizing price volatility has not traditionally been a factor in PSNC's "best cost" policy. Although PSNC could minimize price volatility by locking in gas prices at $15/dt, that would not, in PSNC's view, constitute the "best cost." Ms. Russell testified that PSNC has no current plans to revise its "best cost" strategy to take into account stabilizing measures such as hedging. However, PSNC is aware of and responsive to the fact that those issues are being considered by the Commission.

The Commission has recently initiated an investigation to consider issues related to hedging of natural gas by LDCs in Docket No. G-100, Sub 84. In its brief, the Attorney General states that that proceeding may provide guidance to LDCs "in time," but meanwhile, it asks that PSNC expand its best cost policy to include "rate stability" as one of the key factors considered. The hedging proceeding was convened to address certain concerns regarding price volatility on a generic basis. The issues involved are, to a considerable extent, generic in nature. As a result, the Commission will defer consideration of hedging issues to that proceeding.

Based upon the foregoing, the Commission concludes that PSNC appropriately relied upon its "best cost" supply strategy during the review period.

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

The evidence supporting these findings of fact is found in the testimony of PSNC witnesses Russell and Hall and Public Staff witness Davis.

PSNC Russell testified that approximately 44% 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. The majority of these customers have the capability to use a fuel other than natural gas (for example, distillate fuel oil, residual fuel oil or propane), and will use those alternate fuels when they are priced below natural gas. The remainder of PSNC's sales is primarily to residential and small commercial customers. Electricity is PSNC's primary competitor for this market segment.

PSNC witness Russell testified that the majority of PSNC's interstate pipeline capacity is obtained from Transco. In addition, PSNC has a backhaul transportation arrangement with Transco to redeliver gas from its firm transportation and storage service agreements with Dominion Transmission, Inc. (DTI) and Columbia Gas Transmission Corporation (TCO). PSNC has upstream firm transportation agreements with Texas Eastern Transmission Corporation, Texas Gas Transmission Corporation and Transco. In addition, PSNC has a transportation agreement with Washington Gas Light Company for volumes it receives from the Cove Point LNG facility in Maryland.

With respect to the gas supplies used to support its firm transportation contracts, Russell testified that PSNC has developed a portfolio gas strategy, which includes the execution of long-term supply contracts that conform to PSNC's "best cost" supply strategy. PSNC currently has approximately 235,000 dekatherms per day under term contracts with six major producers and three interstate pipeline marketing affiliates. She testified that all of these contracts have provisions that ensure that the price remains market-sensitive. Ms. Russell further stated that PSNC's gas supply and capacity portfolio has the flexibility necessary to meet its market requirements in a secure and cost-effective manner.

In addition, Ms. Russell indicated that PSNC has undertaken a number of activities to keep its gas costs as low as reasonably possible, while accomplishing its stated policies and maintaining security of supply and operational flexibility:

1. PSNC actively participates in all matters before regulatory and governmental agencies whose actions could reasonably be expected to impact PSNC's rates and services to its customers.

2. PSNC pursued and captured significant opportunities for capacity release and other secondary market transactions. PSNC exhibits and the testimony of Public Staff witness Perry reflect that PSNC earned $8,373,901 in margins on secondary market transactions, including buy/sell and capacity release, during the review period. Of that amount, $6,280,426 ($8,373,901 x 75%) was credited to the All-Customers Deferred Account for the benefit of ratepayers.

3. PSNC has continued to work with its industrial customers to transport customer-owned gas. Transportation services on PSNC's system permit gas to remain competitive with alternate fuels and may allow PSNC to maintain throughput without having to negotiate its regular rate schedules.

4. PSNC regularly communicates with customers, numerous supply sources, and other industry participants, and actively researches and monitors the industry using a variety of sources, including industry trade periodicals. In response to questions from CUCA under cross-examination, PSNC witness Russell described the process of cross-checking she undertakes to determine and support the market price for the release of capacity.

5. PSNC has frequent internal discussions among various senior level officers concerning gas supply policy and major purchasing decisions.

6. During the review period, PSNC renegotiated certain pricing terms associated with five of its long-term supply agreements to ensure that charges accurately reflect market conditions.

7. PSNC continually evaluates various capacity and supply options to ensure that future peak day requirements will be met.

PSNC witness Russell testified that PSNC acquired no additional interstate pipeline capacity or storage services during the test period.

Public Staff witness Davis testified that he had reviewed PSNC's gas supply contracts to determine how the commodity or variable costs were determined. Mr. Davis then reviewed transportation and demand contracts for any reservation or fixed gas costs fees that were charged during the review period. He supported PSNC's assertion that all of the Company's long-term contracts have provisions that ensure the prices paid remain market-sensitive.

Public Staff witness Davis testified that he considered other information received in response to Public Staff data requests concerning PSNC's future needs, including the following:

1. design day estimates;

2. forecasted load duration curves;

3. forecasted gas supply needs;

4. projection of capacity additions and supply changes, and

5. customer load profile changes

Public Staff witness Davis testified that, based upon his review of this information, PSNC's gas costs were prudently incurred during the review period.

Based upon the foregoing, the Commission concludes that the gas costs incurred by PSNC during the 12-month period ending March 31, 2001, were reasonable and prudently incurred.

In the Order in PSNC's last annual review of gas costs (Docket No. G-5, Sub 414), the Commission discussed PSNC's participation in matters before regulatory and governmental agencies whose actions could reasonably impact PSNC's rates and services. The Commission stated in the Order in that docket that it intended, "... to scrutinize PSNC's involvement in such matters carefully in PSNC's next annual prudency review."

PSNC witness Russell testified that, "PSNC actively participates in all matters before regulatory and governmental agencies whose actions could reasonably be expected to impact PSNC's rates and services to its customers." However, in spite of the Commission's warning in Docket No. G-5, Sub 414, PSNC put on witnesses in this docket who were not in a position to adequately discuss these issues.

In its brief, CUCA argues that the record in this proceeding fails to show that PSNC adequately scrutinized the costs that its interstate affiliate sought to pass through to PSNC's ratepayers and further argues that that should preclude a finding of prudence. This Commission is aware of the limitations that federal law imposes on its ability to challenge the reasonableness of rates set by federal regulators. It does not presume to rule on whether or not the rates set by the Federal Energy Regulatory Commission are just and reasonable. Instead, it seeks to monitor PSNC's behavior. If such behavior is not found to be acceptable, an appropriate remedy will be found outside of the disapproval of FERC-approved rates.

The Commission reiterates its concern over the potential conflicts of interest that arise from PSNC being a partner in and doing business with entities whose rates are set by federal regulators and passed through to North Carolina ratepayers. It also reiterates its determination to use these annual gas cost reviews as a vehicle to monitor PSNC's activities in federal proceedings. In its brief, CUCA notes that, in North Carolina Natural Gas Company's (NCNG's) last annual gas cost review, the Commission expressed dissatisfaction with answers given by NCNG's witnesses with regard to this issue and concluded that NCNG should be required to file a detailed explanation in its next annual review. CUCA asks that PSNC be required to do the same. The Commission agrees and concludes that, in its next annual gas cost review, PSNC should file a detailed explanation, by a knowledgeable witness, of what actions it has taken to ensure that the costs passed through to rate payers from its Pine Needle affiliate and from its business partner, Transco, are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12 and 13

The evidence for this finding of fact is contained in the testimony of PSNC witness Russell and Public Staff witness Perry, the Code of Conduct contained in Docket Nos. G-5, Sub 400 and G-43 and the communication to the Commission dated August 2, 2001, in Docket No. G-5, Sub 366, of which the Commission took judicial notice.

The Commission order of December 7, 1999, approving the merger between PSNC and SCANA Corporation includes a Code of Conduct governing the relationship among PSNC and its affiliates. The Cost Allocation and Transfer Pricing Standards of that Code generally require PSNC to purchase goods and services from an affiliate at the lower of market value or the affiliate's cost.

During the test period, PSNC utilized different affiliates to purchase commodity gas and to handle its secondary market transactions. As set forth in the August 2, 2001, letter to the Commission in Docket No. G-5, Sub 366, PSNC, on October 28, 1996, presented to the Commission a Gas Sales Agreement and an Agency Agreement under which PSNC and a joint venture, Sonat Public Service LLC would engage in certain transactions. Fifty percent of Sonat Public Service LLC was owned by PSNC subsidiary PSNC Production and 50% was owned by Sonat Marketing Company. The Gas Sales Agreement applied to spot purchases of commodity gas. The Agency Agreement governed secondary market transaction.

Following the merger, PSNC Production purchased Sonat Marketing Company's 50% interest in Sonat Public Service. Effective April 24, 2000, the name of Sonat Public Service was changed to SCANA Public Service Company, LLC. As a part of a corporate reorganization, effective January 1, 2001, PSNC Production and SCANA Public Service Company, LLC, became a part of SCANA Energy Marketing, Inc. (SEMI). No modifications were made to any of the underlying agreements.

PSNC witness Russell elaborated on the process by which she determines market price for the sale of capacity to affiliates and non-affiliates, and the extent to which she considers multiple sources in making such determinations. She uses as a guideline the information available on the Transco bulletin board, which shows, on a real time basis, postings for capacity release where other parties have sold capacity. She testified that she also obtains information from various marketers and shippers that she deals with on a routine basis as a gauge for determining a reasonable market price for the release of that capacity.

Public Staff witness Perry testified as to the Public Staff's review of PSNC's secondary market activity and relationship with its affiliated natural gas marketing companies during the review period. She described the corporate relationships leading to PSNC's existing arrangement with its natural gas marketing affiliate, SEMI. She testified that the business activities now conducted by SEMI include the marketing of PSNC's assets, gas supply contracts, pipeline capacity rights and gas storage contracts. She further testified that in the course of the Public Staff's review of secondary market transactions, they examined entries recorded in the deferred accounts, detailed supporting workpapers and supplier invoices, as well as the financial books and records of the gas marketing affiliates. On the basis of that review, the Public Staff concluded that PSNC properly accounted for its gas costs during the review period.

During cross-examination, CUCA questioned PSNC witness Russell concerning PSNC's gas purchases from its affiliate, SEMI, under the Gas Sales Agreement. Specifically, CUCA asked about purchases from SEMI at other than a "bid week" price as described in the Agreement, set at the first of the month. Witness Russell testified that it is PSNC's practice to abide by the Code of Conduct and buy at the lower of cost or market. CUCA's questions incorrectly assume that the "bid week" price in the agreement establishes the market price for purposes of the Code of Conduct. As Ms. Russell testified, and the terms of the Agreement reflect, the language establishes no such correlation. She testified that the bid week price is set at the first of the month, whereas the market price may vary from day to day and may be lower than the bid week price established at the beginning of month. She testified that SEMI sells gas to PSNC at its cost, without charge or markup, and that PSNC treats the actual cost as indicative of the market price on that particular date.

In its brief, CUCA does not pursue the question of market pricing by SEMI that it raised on cross-examination at the hearing. However, it does contend that Section 3.1 of PSNC's Gas Sales Agreement is not consistent with PSNC's Code of Conduct and should be modified. This contract covers purchases of PSNC's spot market needs, apart from any contracts PSNC might sign with other parties for firm, long-term gas purchases. Section 3.1 of the agreement grants to SEMI, as the successor to Sonat Public Service LLC and PSNC Production, the discretion to set the price for the commodity gas sold to PSNC up to PSNC's Initial Daily Nominated Quantity at either cost or "bid week" price. The Code of Conduct states that untariffed goods provided by an affiliate must be transferred at the lower of market value or fully distributed cost (Paragraph D(1)(b)).

As CUCA notes, it appears that the contract is written in such a way that, if SEMI chose to exercise its discretion to set the price of the commodity gas sold to PSNC, and did so in such a way that did not result in the gas being transferred at the lower of market value or fully distributed cost, and PSNC paid SEMI's price, the Code of Conduct would be violated. The original contract between PSNC and Sonat Public Service Company LLC (which, for practical purposes, is now SEMI) was entered into on December 1, 1996 and the Code of Conduct was not approved until three years later. As noted above, the contract has not been modified. However, the Commission concludes that Ms. Russell's testimony is sufficient to establish that the way that gas is now being purchased under the contract is consistent with the Code of Conduct. Because no harm is now being done and a remedy is in place if harm was being done, the Commission will not mandate any action. The Commission will, however, continue to carefully scrutinize such transactions in order to ensure compliance with PSNC's Code of Conduct.

In its brief, CUCA also notes that PSNC gets to keep 25% of the net margin on secondary market transactions and contends that, in order to avoid abuse, competitive bidding should be used to determine the "true market price" of released capacity. CUCA did not demonstrate the validity of the proposition that the only way to establish "true market price" is through competitive bidding by PSNC. Witness Russell's testimony concerning the appropriateness of the steps taken to establish a market price is convincing.

CUCA also argues in its brief that each amendment of the contract between PSNC and PSNC Production regarding the release of capacity should be filed with the Commission. Counsel for CUCA asked PSNC witness Russell, "Do you know if PSNC files these pricing amendments with the Commission?" She answered, "I do not know." CUCA asks that the Commission take judicial notice of PSNC's filings in Docket No. G-5, Sub 366, the docket in which the affiliate contract was originally filed. A review of the filings in that docket shows that no amendments have been filed. The original contract does not address periodic renegotiation of any terms or conditions. The Commission therefore concludes that the Company should file the amendments.

On the basis of the information presented, the Commission concludes that the actions taken pursuant to the agreements with SEMI are reasonable, in compliance with the Code of Conduct, and that the costs incurred thereunder during the review period were reasonable and prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the testimony of PSNC witness Hall and Public Staff witness Davis.

In prefiled testimony, PSNC witness Hall testified that PSNC requested the Commission to approve the March 31, 2001 balances in its deferred gas cost accounts. Further, PSNC requested approval to discontinue the decrement of $.00614 per therm approved in its 2000 annual review and to implement a decrement of $.01910 per therm to refund the amount due to all customers. Ms. Hall testified that PSNC does not seek to recover the amount owed by sales customers because it anticipates a reduction in this balance prior to the implementation of any increment that would be approved.

Public Staff witness Davis testified that while he agreed with PSNC's proposal to discontinue the current decrement associated with the Sales-Only Deferred Account, he did not agree with the Company's proposal to implement a decrement of $.01910 per therm to refund the amount associated with the All-Customers Deferred Account.

Mr. Davis testified that according to Commission Rule R1-17(k)(4)(a), temporary increments or decrements in the All-Customers Deferred Account are determined based on the fixed gas costs apportionment percentages as determined in the Company's most recent general rate case. Therefore, the refund should be unique and specific to each rate schedule. Mr. Davis calculated the allocation for each rate schedule in Davis Exhibit A, which also shows, by rate schedule, the percentage allocation, the amount, and the associated volume level.

In testimony from the stand, PSNC witness Hall testified that PSNC did not object to the changes in the refund proposal contained in Mr. Davis' testimony.

The Commission therefore concludes that it is just and reasonable to discontinue the decrement associated with the Sales-Only Deferred Account, and to implement the decrement for the All-Customers Deferred Account in the manner set forth in Mr. Davis' exhibit.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is found in the testimony of PSNC witness Hall and Public Staff witnesses Davis and Perry.

PSNC witness Hall testified that the Company credited customers with $1.4 million under the "Other" category on Schedule 9, Summary of Deferred Account Activity, All-Customers Account. On cross-examination by CUCA, Ms. Hall testified that the credit represented the calculation of the Lost and Unaccounted for and Company use gas true-up for the 12-month period ending June 30, 2000. She testified that the calculation represents a formula based upon total throughput that the Commission allowed the Company to use in determining Lost and Unaccounted for gas in its last rate case. She further testified that PSNC credited all customers with the amount reflected by the true-up because the cost of lost gas is billed to all customers, rather than just sales customers.

Also in response to CUCA cross-examination, Public Staff witness Perry testified that in the course of its review of PSNC's gas costs, it looked at the level of adjustment for lost gas during the test year. Ms. Perry testified that the Public Staff looked at the numbers themselves, and the documentation behind the numbers as well. She testified that the Public Staff is also involved in the annual true-up, to verify the calculation for truing up the Lost and Unaccounted for gas. She testified that they verify the benchmark for each month to determine whether the true-up was calculated correctly and compare it to the base period level, the rate case level that the Commission has established.

Public Staff witness Davis testified that the determination of Lost and Unaccounted for gas involves verifying system supply, and determining volumes of gas delivered to the city gate as opposed to that actually sold to customers. Public Staff witness Davis further testified that numerous reasons exist for Lost and Unaccounted for gas, such as leaks in the system, malfunctioning meters, and contractor line breaks. Although a line break is generally easy to detect, a malfunctioning meter is much less apparent and can generate significant gas loss.

In response to CUCA questioning, Public Staff witness Davis testified that the Public Staff reviews Lost and Unaccounted for gas levels from year to year, and has developed an understanding of what is normal for a particular company. He testified that the Public Staff facilitates and evaluates a meter testing program that is in place. It is a statistical meter sampling in which meters are pulled and their relative accuracy determined. Mr. Davis testified that on the basis of his experience, the level of loss experienced by PSNC is "fairly insignificant."

Public Staff witness Davis responded to CUCA regarding the rationale for crediting the lost gas costs, when trued up, to all customers. Mr. Davis explained that the determination of the Lost and Unaccounted for gas calculation is a part of the total evaluation of a rate case. He testified that the gas moved on PSNC's system is comprised of sales gas and transportation gas. When transportation gas reaches the city gate, it becomes a part of total volumes. Because it would be impossible to determine whether lost gas is sales or transportation gas, the only appropriate way to true up Lost and Unaccounted for gas is to include all customers.

The Commission notes that the appropriate forum in which to determine the treatment of Lost and Unaccounted for gas is a general rate case or a rulemaking proceeding. The Commission addressed the proper treatment of Lost and Unaccounted for gas for purpose of the purchased gas adjustment process in Docket No. G-100, Sub 58, in which the Commission held that amounts relating to such volumes should be recovered from all customers. Rule R1-17(k)(4)(c) provides for an annual true-up, which was appropriately conducted in this proceeding and provides for a credit to customers. There does not appear to be a viable challenge to the credit calculated for this review period.

The Commission does recognize that there was an unprecedented increase in the price of commodity gas last year. It is more of a burden for ratepayers to lose a given volume of gas when the price is $10 per dekatherm than it is when the price is $2 or $3 per dekatherm. However, this is a question that confronts all LDCs and their customers. If consideration should be given to a general change in the way these costs are treated, a generic docket would be the appropriate forum.

Based on the foregoing, the Commission concludes that the $1.4 million credit to all customers is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

Support for the Commission's findings is found in the testimony and exhibits of PSNC witness Hall.

In her prefiled testimony, PSNC witness Hall presented information regarding credits and charges reflecting Rider F activity. In response to CUCA cross-examination, Ms. Hall testified extensively regarding Rider F. She explained that Rider F was approved during PSNC's last general rate case when the Company decided to do away with the requirement that Large Customers have an alternate fuel in order to qualify for Rate Schedule 150. Rider F was created to allow the Company to recover margins that might be lost as a result of customers switching from Rate Schedule 145 to Rate 150. When PSNC recovers margins as a result of customers moving from one Rate Schedule to the other, the Company credits the All-Customers Deferred Account. When margins are lost, PSNC charges customers.

CUCA asked a number of questions regarding PSNC's interpretation of Paragraph 5 of Rider F, which it introduced into evidence as CUCA Hall Cross Examination Exhibit 3. Paragraph 5 of the section entitled "Computation of the Rate Schedule Adjustment" provides as follows:

> Differences between current Billing Rate and Base Billing Rate that ***originate*** more than 24 months subsequent to the effective date of the Commission's Order in Docket No. G-5, Sub 386, shall be excluded from these computations. [Emphasis Added]

In response to CUCA questions, PSNC witness Hall testified that under the terms of Paragraph 5, PSNC did not add any customers to Rider F after 24 months, or two years, following the date of the Commission's order--October 31, 2000. She testified that PSNC does not agree with CUCA's suggestion, in its questions, that the computation of any difference between the current billing rate and the base billing rate is to cease after 24 months from the date of the order. She stated that the Company takes the position that the customer base to which Rider F applies does not increase after the 24-month period. Under CUCA's interpretation, the term "originate" has no meaning.

By its terms, Rider F does not allow the computation of differences between the billing rate and the base billing rate that "originate," or come into existence, after October 31, 2000. Its language contains no termination provision for the computation of differences between the billing rate and the base billing rate that exist prior to that time.

Because the Commission approved Rider F in Docket No. G-5, Sub 386, and the plain language of the Rider supports PSNC's interpretation of its applicability, the Commission concludes that PSNC should be allowed to credit and recover the amounts reflected as Rider F activity in the All-Customers Deferred Account for the review period.

IT IS, THEREFORE, ORDERED

1. That PSNC's accounting for gas costs and recoveries during the 12-month review period ending March 31, 2001, be, and the same hereby is, approved; and

2. That the gas costs incurred by PSNC during the 12-month review period ending March 31, 2001, were reasonable and prudently incurred, and PSNC be, and hereby is, authorized to recover its gas costs as provided herein; and

3. That PSNC refund the $13,211,253 balance to customers in its All-Customers Deferred Account in accordance with Davis Exhibit A; and

4. That PSNC shall file all amendments to its buy-sell agreement with PSNC Production pursuant to G.S. 62-153(a); and

5. That, in its next annual review of gas costs, PSNC shall file a detailed explanation of what actions it has taken to ensure that the costs passed through to rate payers from its Pine Needle affiliate and from its business partner, Transco, are just and reasonable.

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

wg110801.01

DOCKET NO. G-9, SUB 451

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: October 2, 2001, at 10:00 a.m., Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner James Y. Kerr, II, Presiding; Commissioner J. Richard Conder and Commissioner Sam J. Ervin, IV

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

Jerry W. Amos and James H. Jeffries, Nelson Mullins Riley & Scarborough, LLP, Bank of America Corporate Center, Suite 3350, 100 North Tryon Street, Charlotte, North Carolina 28202-4000

For the Using and Consuming Public:

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

Margaret A. Force, Associate Attorney General, North Carolina Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On August 1, 2001, Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed (1) the direct testimony of Keith P. Maust, Director of Gas Supply and Market Sales, (2) the direct testimony and exhibit of Kenneth T. Valentine, Director, Federal Regulatory and Supply Planning and (3) the direct testimony and exhibits of Ann H. Boggs, Director of Gas Accounting, relating to the annual review of Piedmont's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On August 9, 2001, the Commission issued an Order scheduling a public hearing for October 2, 2001, setting dates for pre-filed testimony and intervention, and requiring public notice.

On August 15, 2001, the Attorney General of the State of North Carolina gave notice of intervention.

On August 24, 2001, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, and on August 29, 2001, the Commission issued an order granting the petition.

On September 17, 2001, the Public Staff filed the testimony of Julie G. Perry, Supervisor, Natural Gas Section, Accounting Division of the Public Staff and Jeffrey L. Davis, Director, Natural Gas Division of the Public Staff.

On October 2, 2001, the matter came on for hearing as scheduled.

Based upon the evidence adduced at the hearing 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. Piedmont has filed with the Commission and submitted to the Public Staff all of the information required by G.S. 62-133.4(c) and Commission Rule R1-17(k) and has complied with the procedural requirements of such statute and rule.

4. The review period in this proceeding is the twelve months ended May 31, 2001.

5. During the review period, Piedmont incurred gas costs of $418,153,609, received $419,358,727 of this amount through rates, and credited the difference to the appropriate deferred accounts.

6. At May 31, 2001, the Company had a credit balance of $19,008,381 in its deferred accounts consisting of a debit balance of $364,435 in the commodity or Sales Only Deferred Account and a credit balance of $19,372,816 in the demand or All Customers Deferred Account.

7. During the review period, the Company realized net compensation of $14,261,126 from secondary market transactions. In accordance with the Commission's Orders in Docket Nos. G-100, Subs 63 and 67 and Docket No. G-9, Sub 317, $10,695,845 of the net compensation was treated as a reduction in gas costs for the benefit of Piedmont's customers.

8. Piedmont properly accounted for its gas costs during the review period.

9. Piedmont has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to Piedmont's system and long term supply contracts with producers, marketers and other suppliers.

10. Piedmont has adopted a "best cost" gas purchasing policy 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.

11. 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.

12. The Company should be permitted to recover 100% of its prudently incurred gas costs.

13. The Company's decision to arrange an early termination of a contract pursuant to which it purchased a liquified natural gas (LNG)-based firm peaking service under Transcontinental Gas Pipe Line Corporation's Rate Schedule LGA and to replace it with a 15,000 dekatherm (dt) per day firm service to be provided under a service agreement with Pine Needle LNG Company, LLC (Pine Needle) was prudent.

14. Piedmont proposed to refund the net credit balance in its All Customers Deferred Accounts based on the fixed gas costs apportionment percentages for each rate schedule as set forth in the Commission's order in Docket No. G-9, Sub 428.

15. Piedmont proposed to refund the May 31, 2001 balance in its All Customers Deferred Account by implementing the appropriate decrements for each rate schedule beginning with the first billing cycle of the month that follows the date of this order. The appropriate decrements are set forth in Exhibit A to the testimony of Jeffrey L. Davis.

16. Piedmont proposed to carry forward the May 31, 2001 debit balance in its Sales Only Deferred Account to offset future over-collections.

17. Piedmont shall file with the Commission within 30 days of execution, a redacted copy of all negotiated sales contracts of more than one month but less than or equal to one year. Such contracts shall be subject to review in the Company's next annual prudence review. Negotiated contracts of more than one year shall require Commission approval prior to becoming effective.

18. Piedmont's Expansion Fund balance of $5.3 million should continue to be held by the State Treasurer of North Carolina until further order of the Commission.

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

The evidence supporting these findings is contained in the official files and records of the Commission and the testimony of Piedmont witness Maust. 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 testimony of Piedmont witness Boggs and Public Staff witness Perry.

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical twelve-month test period concerning 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 information and data showing weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Ms. Boggs testified that Piedmont 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). Ms. Perry confirmed that the Public Staff had reviewed the filings and that they complied with the Rules.

The Commission therefore concludes that Piedmont 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 - 8

The evidence supporting these findings is contained in the testimony of Piedmont witnesses Maust and Boggs and Public Staff witnesses Perry and Davis.

In her prefiled testimony, Ms. Boggs testified that, as of May 31, 2001, Piedmont had a credit balance of $19,008,381 in its deferred accounts. The credit balance consisted of a debit balance of $364,435 in the Sales Only Deferred Account and a credit balance of $19,372,816 in the All Customers Deferred Account. Public Staff witness Perry testified that Piedmont had properly accounted for its gas costs during the review period.

Mr. Maust and Ms. Perry testified that Piedmont achieved net compensation of $14,261,126 from secondary market transactions and that $10,695,845 of this net compensation was treated as a reduction in gas costs for the benefit of Piedmont's customers in accordance with procedures established in Docket No. G-100, Sub 63 and Docket No. G-100, Sub 67. No party offered any evidence to show that Piedmont did not record its gas costs in compliance with the previously approved procedures; therefore, the Commission finds and concludes that Piedmont has properly accounted for these transactions.

Based on the foregoing, the monthly filings by Piedmont pursuant to Commission Rule R1-17(k)(5)(c), and the findings of fact set forth above, the Commission concludes that Piedmont properly accounted for its gas costs during the review period and that the deferred account balances as reported are correct.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9 - 12

The evidence supporting these findings is contained in the testimony of Piedmont witness Maust and Public Staff witness Davis.

Mr. Maust testified that Piedmont'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. Mr. Maust stated that all of these components are interrelated and that Piedmont considers and weighs each of these five factors in establishing its entire supply portfolio.

Mr. Maust further testified that Piedmont purchases gas supplies under a diverse portfolio of contractual arrangements through the spot market and through long-term contracts. Spot gas is purchased under a contract with a term of one month or less while long-term gas is purchased under a contract ranging in term from one year (or less) to terms extending through October, 2004. 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, firm supplies are the most reliable and secure source of gas. Some of these firm contracts are for winter service only and some provide for 365 day service.

Mr. Maust described how the interrelationship of the five factors affects Piedmont'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, Piedmont must be kept informed about all aspects of the natural gas industry. Piedmont therefore stays abreast of current issues by intervening in all major proceedings affecting pipeline suppliers, attending conferences, and subscribing to industry literature.

Mr. Maust stated that Piedmont's greatest obstacle 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, weather patterns, regulatory policies, and industry restructuring in the energy markets. Future availability and pricing of gas supplies is affected by overall demand, domestic oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. Mr. Maust further stated that Piedmont did not make any changes in its "best cost" gas purchasing policies or practices during the year.

Finally, Mr. Maust testified that Piedmont had taken a number of steps to manage its gas costs, consistent with its "best cost" policy. The Company has participated in matters before the Federal Energy Regulatory Commission (FERC) and other regulatory agencies, actively renegotiated and restructured eligible supply and capacity contracts in order to take advantage of market opportunities, utilized the flexibility available within its supply and capacity contracts to purchase and dispatch gas and to release capacity in the most cost effective manner, actively promoted more efficient peak day use of natural gas and load growth from "year around" markets in order to improve the Company's load factor and reduce average unit costs, and continued an internal review committee to receive input and direction on its gas supply performance and planning activities.

Mr. Davis testified that he had reviewed the Company's gas supply contracts to determine how the commodity and variable costs were determined. He then reviewed the transportation and demand contracts for any reservation or fixed gas costs fees that were charged during the review period. In addition, Mr. Davis stated that he reviewed information related to (1) design day estimates and requirements, (2) forecasted load duration curves, (3) forecasted gas supply needs,

(4) projections of capacity addition and supply changes, (5) customer load profile changes, and (6) potential capacity and storage opportunities. Mr. Davis stated that, in the Public Staff's opinion, Piedmont's gas costs were prudently incurred.

In its Brief, the Attorney General recommended that Piedmont expand its "best cost" supply policy to include "rate stability" as one of the key factors considered and evaluate the cost and benefits of hedging to stabilize rates as part of the gas cost planning procedure. The Attorney General states that Piedmont took a number of steps to mitigate the impact of price increases on consumers. The dramatic increases in rates were attributable to much higher wellhead prices experienced during the period. Piedmont used its benchmark to soften the impact of those price increases on consumers. As a result, the benchmark cost of gas during the annual review period increased slower than the market price of natural gas. Storage was also used to hedge gas prices as much as possible during the review period. These are tools that Piedmont has used in the past, and it continues to rely on these tools in its planning process to moderate rates for consumers going forward. Nonetheless, even when Piedmont used these tools as much as possible during the review period, customers still experienced increases of between 40 and 50 percent in their rates last year.

Further, although Piedmont did not consider rate stability to be a primary focus in its gas purchasing strategy during the review period, Piedmont, to its credit, has taken steps to evaluate the use of hedging and other new measures that might be taken to stabilize rates going forward. Piedmont announced in the hearing that it would file a Petition for approval of a hedging pilot program, and did so that same day in Docket No. G-9, Sub 454.

The Commission has initiated an investigation to consider issues related to hedging of natural gas by LDCs in Docket No. G-100, Sub 84. The hedging proceeding was convened to address certain concerns regarding price volatility on a generic basis. The issues involved are, to a considerable extent, generic in nature. As a result, the Commission will defer consideration of hedging issues to that proceeding.

Based on the foregoing, the Commission concludes that Piedmont's gas purchasing policy and practice during the review period were 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. 13

The evidence supporting this finding is contained in the testimony of Piedmont witness Valentine.

Mr. Valentine testified that during the test period, Piedmont arranged an early termination of a contract pursuant to which it purchased a LNG-based firm peaking service under Transco's Rate Schedule LGA and replaced it with a 15,000 dt per day firm service agreement to be provided by Pine Needle, effective October 1, 2000. On November 20, 2000, Piedmont filed the Pine Needle contract and associated agreements with the Commission and noted that this additional Pine Needle acquisition would be subject to full Commission review in Piedmont's next annual gas cost review proceeding. The Commission's subsequent order of December 22, 2000, accepted the Pine Needle agreements for filing and provided for review of the recovery of costs related thereto.

Mr. Valentine testified that the replacement of the LGA service with Pine Needle service was predicated on several factors, including the following: (1) LGA service is provided under the authority of Section 7(c) of the Natural Gas Act and, therefore, Piedmont had no way to market unutilized LGA capacity as secondary transactions to mitigate contract demand costs; (2) the fuel retention factor associated with the LGA Service had recently risen dramatically to more than 45%; and (3) the discounted Pine Needle LNG service provides added flexibility and was not more expensive than the LGA service when taking the additional days of service under Pine Needle into account.

No evidence was introduced by any party to suggest that Piedmont's decision to substitute the Pine Needle service for the LGA service was not prudent.

Based on the foregoing, the Commission concludes that Piedmont's decision to substitute the Pine Needle service for the LGA service is prudent.

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

The evidence supporting these findings is contained in the testimony of Piedmont witness Boggs and Public Staff witness Davis.

Ms. Boggs testified that Piedmont proposes to place a decrement in its rates to refund the credit balance in its demand deferred account. This decrement will be effective the first billing cycle of the month following the Commission's Order approving the appropriate rate changes. She further testified that because Piedmont expects to under-collect demand charges during the 2001 summer and to pay increased demand charges as a result of Transco's pending rate case, Piedmont also proposes to place an offsetting increment in its rates.

Mr. Davis testified that the Public Staff did not believe that the pending Transco rate case justifies an offsetting increment and that Piedmont's Purchased Gas Adjustment mechanism provides a more appropriate means to track interstate pipeline charges than temporary increments. Mr. Davis' Exhibit A sets forth the appropriate decrement for each rate schedule. Ms. Boggs testified that Piedmont did not intend to place an offsetting increment into effect in this docket but rather to file for such an increment under Piedmont's Purchased Gas Adjustment mechanism if circumstances continue to warrant such a filing.

Ms. Boggs testified that since the debit balance in the Sales Only or commodity deferred account is *de minimus*, Piedmont does not propose to place an increment in its rates at this time to recover this under-collection. Instead, the balance will be carried forward and used to offset future over-collections. No party objected to this proposal.

The Commission finds that the rates proposed by Mr. Davis in his Exhibit A are appropriate and should be implemented on the first billing cycle of the month following the date of this order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence for this finding of fact is found in the testimony of Public Staff witness Perry.

Ms. Perry pointed out that the Commission had previously required both Public Service Company of North Carolina, Inc. and North Carolina Natural Gas Corporation to file certain multi-month negotiated contracts. She stated that in order to be consistent, the Public Staff was recommending that in the future, negotiated sales and transportation contracts of less than one month may be dealt with through the deferred account without being filed with the Commission. In regard to negotiated sales and transportation contracts of more than one month but less than or equal to one year, she stated that the Public Staff recommended that a redacted copy be filed with the Commission within 30 days of execution. Ms. Perry testified that there would be no pre-approval of such contracts but that they would be subject to review in the next annual prudence review. She stated that negotiated contracts exceeding one year in duration shall be filed with the Commission and shall require Commission approval prior to becoming effective.

The Commission has considered the Public Staff's recommendations regarding negotiated contracts and concludes that they are reasonable and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Perry. She testified that it is the Public Staff's belief that Piedmont's Expansion Fund balance of $5.3 million should continue to be held with the State Treasurer pending the outcome of the appeal in NCUC Docket No. G-3, Sub 228. She stated that the Public Staff recommended that after the outcome of the appeal has been determined, the Company should file testimony in its next annual prudence review detailing the balance in its Expansion Fund and its intentions in regard to these monies. Having carefully considered the Public Staff's recommendations regarding Piedmont's Expansion Fund balance, the Commission finds them reasonable and concludes that these recommendations should be adopted.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont's accounting for gas costs during the twelve months ended May 31, 2001, is approved.

2. That Piedmont is authorized to recover 100% of its gas costs incurred during the twelve months ended May 31, 2001.

3. That Piedmont shall implement the temporary decrements, as shown on Exhibit A to Mr. Davis' testimony, to refund the credit balance related to the All Customers Deferred Account beginning with the first billing cycle of the month immediately following the date of this order.

4. That Piedmont shall carry forward the debit balance related to the Sales Only Deferred Account and such debit balance will be used to offset future over-collections.

5. That the existing decrements to the All Customers Deferred Account approved in the last Annual Review, shall be discontinued.

6. That Piedmont shall give notice to all of its customers of the changes in rates approved in this order by appropriate bill inserts beginning with the first billing cycle that includes the changes in rates approved herein.

7. That Piedmont shall file with the Commission within 30 days of execution, a redacted copy of all negotiated sales and transportation contracts of more than one month but less than or equal to one year in duration. That Piedmont shall also file negotiated contracts with terms of more than one year with the Commission and obtain Commission approval prior to the contracts becoming effective.

8. That Piedmont's Expansion Fund balance of $5.3 million, which is now held by the North Carolina State Treasurer, shall continue to be held by the State Treasurer. In the next annual prudence review following a determination of the appeal in NCUC Docket No. G-3, Sub 228, Piedmont shall file testimony detailing the Expansion Fund balance and its intentions in regard to these monies.

ISSUED BY ORDER OF THE COMMISSION
This the 7th day of November , 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

db120601.02

DOCKET NO. G-21, SUB 393

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of North Carolina Natural	)	
Gas Corporation for Annual Review of	)	ORDER ON ANNUAL
Gas Costs Pursuant to G.S. 62-133.4(c)	)	REVIEW OF GAS COSTS
and Commission Rule R1-17(k)(6)	)	

HEARD: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on April 11, 2000, at 9:30 a.m. and August 21, 2000, at 1:00 p.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; and Commissioners Ralph A. Hunt and Judy Hunt.

APPEARANCES:

For North Carolina Natural Gas Corporation:

Edward S. Finley, Jr., Hunton & Williams, P.O. Box 109, Raleigh, North Carolina 27602

Bentina D. Chisolm, Associate General Counsel, CP&L Service Company, LLC/North Carolina Natural Gas Corporation, 411 Fayetteville Street Mall, P.O. Box 1551, CBA 13A2, Raleigh, North Carolina 27601

For Carolina Utility Customers Association:

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

For the Using and Consuming Public:

Paul Lassiter, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

Margaret A. Force, North Carolina Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On February 1, 2000, North Carolina Natural Gas Corporation (NCNG or Company) filed the direct testimony and exhibits of Fredrick W. Hering, Principal Analyst, Business Operations Department at NCNG, John M. Monaghan, Jr., Manager, Project Development, Gas Supply and Transportation Dept., Carolina Power & Light Company, and Terrence D. Davis, Senior Vice President of Operations, NCNG, relating to the annual prudence review of NCNG's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6). NCNG filed replacement testimony for Mr. Davis on February 22, 2000.

On February 28, 2000, the Commission issued its order scheduling a public hearing for April 11, 2000, setting dates for pre-filed testimony and intervention in this docket and ordering NCNG to publish notice of these matters in a form of notice attached to the Commission's order.

On February 23, 2000, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, which was allowed by the Commission on March 6, 2000.

On February 29, 2000, Michael F. Easley, Attorney General, filed notice of intervention.

On March 13, 2000, the Commission issued an order on discovery guidelines.

On March 16, 2000, the Presiding Commissioner entered an order on motion to modify procedural schedule that adjusted the dates by which intervenor discovery requests had to be submitted. The Presiding Commissioner entered other orders resolving discovery disputes and addressing procedural issues.

The Public Staff filed the direct testimony of Kirk Kibler, Staff Accountant with the Public Staff's Accounting Division, and Jeffrey L. Davis, Utilities Engineer of the Natural Gas Section, on March 31, 2000. Neither CUCA or the Attorney General filed testimony in this proceeding.

The hearing was conducted as scheduled. Witnesses Hering, Monaghan and Davis for NCNG and witnesses Kibler and Davis for the Public Staff testified.

At the conclusion of the April 11, 2000, hearing the Presiding Commissioner authorized the filing of Briefs and/or Proposed Orders within 30 days after the mailing of the transcript. On May 25, 2000, NCNG and the Public Staff filed a Joint Proposed Order and CUCA filed a brief. On June 12, 2000, NCNG filed a reply brief that indicated, among other things, that various assertions accepted by its witnesses during the initial hearing subject to check were incorrect and requested that the Commission accept certain information contained in an attached Appendix as a late-filed exhibit.

On June 15, 2000, CUCA filed a motion to strike NCNG's reply brief in which CUCA requested the Commission to either strike the reply brief or reopen the hearing. On June 21, 2000, NCNG filed a response to CUCA's motion to strike urging the Commission to deny CUCA's motion. On July 18, 2000, the Presiding Commissioner entered an Order denying motion to strike and reopening the hearing in which the Commission declined to strike NCNG's reply brief, set this matter for further hearing in order to provide CUCA with an opportunity to be heard with respect to any new material contained in NCNG's reply brief, identified what the Presiding Commissioner believed to be the new material set out in NCNG's reply brief, established a procedure for determining whether CUCA contended that additional issues should be considered during the reopened hearing, and indicated that a further opportunity to file briefs would be provided following the reopened hearing.

On July 25, 2000, CUCA filed an identification of certain new and additional information that CUCA believed should be addressed during the reopened hearing and requested a modification of the procedural schedule to permit additional discovery and the filing of testimony. On August 2, 2000, NCNG filed a response in which it objected to any reopening of the discovery process.

On August 7, 2000, the Presiding Commissioner entered an Order further defining scope of hearing that permitted consideration of the additional material identified by CUCA, allowed additional discovery to be conducted prior to the reopened hearing and deferred any ruling on CUCA's other request for modification of the procedural schedule. On August 21, 2000, CUCA filed a motion to continue the hearing and for an order compelling NCNG to respond to further discovery. On August 21, 2000, the Commission denied these motions. In place of the reopened hearing, CUCA tendered the deposition of Mr. Monaghan conducted on August 18, 2000.

Based on the testimony and exhibits and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. NCNG is a public utility as that term is defined in Chapter 62 of the North Carolina General Statutes.

2. NCNG is engaged primarily in the purchase, distribution, and sale and transportation of natural gas to more than 169,250 customers in south central and eastern North Carolina.

3. NCNG has filed with the Commission and submitted to the Public Staff 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 test period for review of gas costs in this proceeding is the twelve months ended October 31, 1999.

5. During the period of review, NCNG incurred gas costs of $120,006,987 and recovered $123,971,222 for gas costs through its rates. This resulted in an over-recovery of $3,964,235. NCNG refunded $6,098,619 through a rate decrement in all sales rates during the review period. NCNG also refunded $1,501,250 to customers using other rate decrements during the test year. The net amount refunded to customers was $7,599,869.

6. During the period from November 1998 through October 1999, NCNG generated a net recoupment of fixed costs amounting to $412,162 as a result of capacity release and buy/sell agreements. Final accounting from a storage capacity management agreement from the previous test period provided an additional $25,838 of fixed cost recoupment. The Company credited 75% of these proceeds to its Deferred Account - All Customers in order to refund these amounts pursuant to the Commission's order in Docket No. G-100, Sub 67.

7. At October 31, 1999, NCNG had a net debit balance of $6,871,584 in its deferred gas cost accounts, consisting of a debit balance of $3,570,731 in the Commodity Deferred Account - Sales Customers Only and a debit balance of $3,300,853 in the Demand Deferred Account - All Customers.

8. The Public Staff took no exceptions to NCNG's accounting for gas costs and recoveries during the period of review.

9. During the period of review, NCNG had transportation and supply contracts with the interstate pipelines that transport gas directly to NCNG's system and term supply contracts with twelve other suppliers.

10. Based on NCNG's contracts with gas suppliers, the gas costs incurred by NCNG during the period of review were prudently incurred.

11. NCNG should be permitted to recover 100% of its prudently incurred gas costs.

12. At the time of the hearing, NCNG did not propose to change its rates.

13. As of the date of the hearing, NCNG had a temporary rate increment of $0.0828 per dekatherm (dt) for the deferred Gas Costs - Sales Customers Only, effective November 1, 1999, and rate decrements ranging from $(.0115)/dt for industrial boiler fuel customers to $(0.0490)/dt for residential-heating only customers, also effective November 1, 1999. The Commission allowed those changes in Docket No. G-21, Sub 386. NCNG proposed that these rate increments and decrements be a part of the Company's rates for twelve months ending October 31, 2000. Subsequently, in Docket No. G-21, Sub 405, the Commission allowed additional changes to increments and decrements.

14. It is just and reasonable to continue the current level of temporary increments and decrements in NCNG's rates until further order of the Commission.

15. NCNG's decision to obtain storage capacity from the Pine Needle LNG Company LLC project was reasonable and prudent.

16. NCNG did not unreasonably favor its marketing affiliates through favorable transfer prices or otherwise.

17. The $167,761 accounting adjustment that NCNG made to its deferred account with respect to the Wiccacon transportation contract is appropriate. The adjustment proposed by CUCA with respect to the Easco contracts is not appropriate. Procedures followed with respect to the contracts were not, on balance, inappropriate; however, new procedures should be established for the future.

18. In the future, negotiated sales and transportation contracts of less than one month may be handled through the deferred account without being filed with the Commission. Negotiated contracts of more than one month but less than one year in duration shall be filed within 30 days of execution. There will be no pre-approval required, but such contracts shall be on file and subject to review in the next annual prudency review. Negotiated contracts of more than one year shall be filed and shall require Commission approval prior to becoming effective.

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

The evidence for these findings of fact is contained in the official files and records of the Commission and the testimony of NCNG witness Monaghan. These findings are essentially informational, procedural or jurisdictional in nature and are facts uncontradicted by any of the parties.

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

The evidence for these findings of fact is contained in the testimony of NCNG witnesses Monaghan and Hering, and the findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that NCNG submit to the Commission information and data for an historical twelve-month review period, which information and data include NCNG'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 there be filed weather-normalized sales volume data, work papers, and direct testimony and exhibits supporting the information filed.

Witness Hering testified that Commission Rule R1-17(k)(6) required NCNG to submit to the Commission on or before February 1, 2000, the required information based on a twelve-month review period ended October 31, 1999. Mr. Hering testified that NCNG complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), and an examination of witnesses Monaghan's and Hering's testimony and exhibits confirms Mr. Hering's testimony. Mr. Hering also testified that NCNG filed with the Commission and submitted to the Public Staff throughout the review period the monthly accounting required by Commission Rule R1-17(k)(5)(c). Public Staff witness Kibler confirmed that the Public Staff had reviewed the filings and that after NCNG made agreed-upon corrections, NCNG would be in compliance with the Commission's rules.

The Commission concludes that NCNG 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 October 31, 1999.

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

The evidence supporting these findings of fact is found in the testimony of NCNG witness Hering and Public Staff witnesses Kibler and Davis.

NCNG witness Hering testified that as of October 31, 1999, NCNG had a debit balance of $6,871,584 in its deferred accounts. This debit balance consists of a debit balance of $3,570,731 in the Commodity Deferred Account - Sales Customers Only and a debit balance of $3,300,853 in the Demand Deferred Account - All Customers.

According to Mr. Monaghan, during the period from November 1998 through October 1999, NCNG received net recoupment of fixed costs amounting to $412,162 as a result of capacity release and buy/sell agreements. Final accounting from a storage capacity management agreement from the previous test period provided an additional $25,838 of fixed cost recoupment. The Company credited 75% of the net compensation from these transactions to its all customers deferred account pursuant to the Commission's order in Docket No. G-100, Sub 67.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Davis and Kibler and Company witness Hering.

Witness Kibler testified that the Public Staff had examined NCNG's accounting for gas costs during the review period and determined that NCNG had, with a few exceptions that NCNG has agreed to rectify, properly accounted for its gas costs.

Based upon the testimony and exhibits of the witnesses, the monthly filings by NCNG as required by Commission Rule R1-17(k)(5)(c) and the finding of fact set forth above, the Commission concludes that NCNG has properly accounted for gas costs during the period of review.

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

The evidence supporting these findings of fact is found in the testimony of NCNG witnesses Davis, Monaghan and Hering and Public Staff witness Davis.

Witnesses Davis testified that the primary objective of NCNG's gas supply acquisition policy is to ensure that the Company has adequate volumes of competitively priced natural gas to meet the peak day demands of all firm customers on its system and to provide the maximum service possible to all customers during the other times throughout the year. Witness Davis described the policy as a "best cost" policy. The key features of the policy include the requirement of a "portfolio mix" of long-term supply contracts, that the backup of peak gas supplies is maintained (mainly in the form of gas in storage), and that firm gas supplies be acquired primarily to meet peak-season firm requirements.

NCNG sells or transports gas to two groups, which are its firm and interruptible markets. Its firm market is principally residential, commercial and small industrial. NCNG's firm market also includes customers that have firm contracts for the purchase or transportation of certain volumes of gas and demand charges in their rates, including NCNG's four municipal customers.

Witness Monaghan testified that NCNG has twelve long-term supply contracts, including the Transcontinental Gas Pipe Line Corporation (Transco) FS sales service contract, representing a total firm supply of 182,547 dts per day for winter delivery and lesser amounts in the remainder of the year. Mr. Monaghan also testified that of these twelve contracts, four are winter only contracts, which are utilized only during the five winter months. Mr. Monaghan further stated that five of the remaining contracts provide higher quantities in the winter months than the summer months, and the remaining three contracts have a level contract quantity year-round.

Mr. Monaghan testified that NCNG continued to have 5,199 dekatherms per day of Rate Schedule FSS (firm storage service) and related transportation from Columbia Gas Transmission, 2,070 dekatherms per day of GSS storage service from Transco, and 5,320 dekatherms per day of Transco's five-day LGA peaking service, as well as NCNG's on-system Barragan LNG peaking facility which can provide in excess of 100,000 dekatherms on a peak day.

Public Staff witness Davis stated that, in addition to reviewing responses to the data requests posed to NCNG, the Public Staff reviewed gas purchase and transportation contracts; reservation or fixed cost fees; design day estimates; forecasted load duration curves; forecasted gas supply needs; customer load profile changes; and projections of capacity additions and supply changes. Based upon the examination of the data which the Public Staff had, Mr. Davis testified that, in the Public Staff's opinion, NCNG's purchasing practices were reasonable and prudent.

The Commission concludes that the gas costs incurred by NCNG during the review period ended October 31, 1999, were reasonable and prudently incurred, and NCNG should be permitted to recover 100 percent of its prudently incurred gas costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 THROUGH 14

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Hering and Public Staff witness Davis.

Mr. Hering testified that, as of the date of the hearing, NCNG had in rates a temporary rate increment of $0.0828 per dt for the Deferred Gas Costs - Sales Customers Only effective November 1, 1999, and rate decrements ranging from S(.0155) per dt for industrial customers to $(0.0490) per dt for residential - heating only customers also effective November 1, 1999. These rate increments and decrements were proposed to be in the Company's rates for the twelve months ending October 31, 2000.

Public Staff witness Davis testified that he agreed with the Company's proposal not to change its rates at this time. The Commission notes that further changes in NCNG's increments and decrements were made in Docket No. G-21, Sub 405, effective November 1, 2000.

The Commission believes that it is just and reasonable to continue the increments and decrements in NCNG's rates until further order by the Commission.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NO. 15

The evidence for this finding of fact is contained in the testimony and exhibits of NCNG witnesses Davis and Monaghan and Public Staff witness Davis.

In its order dated December 21, 1999, in Docket No. G-21, Sub 389, the Commission directed NCNG to justify the prudence of purchasing liquefied natural gas storage capacity from Pine Needle LNG Company LLC (Pine Needle), an interstate storage facility in which NCNG, through an affiliate, has an equity interest.

NCNG began receiving service from Pine Needle pursuant to a FERC-approved rate schedule on May 1, 1999, during the review period in this case.

NCNG made the decision to participate in the Pine Needle project in 1995 in anticipation of a projected shortage in capacity to meet the peak demand from NCNG's firm residential, commercial and high priority industrial customers for the 1999-2000 winter. NCNG projected a need for additional peaking capacity in close proximity to the 1999-2000 winter in order to support the expected demand requirements based on a 20% colder-than-normal weather scenario. No party contested the need for additional peaking capacity.

In addition to the needed storage capacity, NCNG desired an additional interstate pipeline delivery point closer to the midpoint of its service area. In light of these needs, NCNG undertook a study of the potential storage alternatives available to meet the Company's needs.

After undertaking this study, NCNG determined that the best storage alternative was to participate in the Pine Needle project. The projected total costs of Pine Needle were $3,082,589. The projected fixed costs were $2,249,255. The projected cost of the volumes NCNG was to receive from Pine Needle to meet its winter peak demand was $4.686/dt. None of the other off-system alternatives was available at total costs more favorable than Pine Needle. The site of Pine Needle is in Guilford County on Transco's transmission line. The Pine Needle volumes were to be delivered through the Cardinal Extension project, a pipeline that would terminate at Clayton, near the mid-point of NCNG's system. By taking receipt of the volumes at this central location, NCNG could avoid expenditures to upgrade infrastructure such as added compression or pipeline looping to improve reliability and the construction of a satellite LNG plant in Wilmington that otherwise would have been necessary to enable expansion into the Jacksonville and Wilmington areas.

NCNG witness Monaghan discussed the off-system storage options NCNG considered prior to its 1995 decision to participate in the Pine Needle project and enter into the contract to acquire services from Pine Needle.

NCNG investigated three separate market area storage projects in 1995 proposed in New York and Pennsylvania. Access to these projects was to occur through a proposed expansion of Transco's Leidy Line in Pennsylvania and New Jersey with backhaul delivery to NCNG on Transco's main line from the terminus of the Leidy Line.

Developers of two of these proposed projects proposed a high deliverability 10-day peaking service. The developer of the third project proposed 60-day or 110-day seasonal storage service.

A potential alternative transportation route from the three projects was through an expansion of CNG Transmission Corporation's pipeline system from Leidy, Pennsylvania to CNG's interconnection with Transco at Nokesville, Virginia, with back-haul delivery on Transco's main line from Nokesville to NCNG.

NCNG estimated that its fixed cost of service from these storage projects at the contract level equivalent to that contemplated for Pine Needle, including pipeline capacity in and out of the storage facilities, ranged from $4.8 million to $7.4 million.

NCNG considered a fourth alternative project proposed by a partner in one of the New York/Pennsylvania market area storage projects. The developer of this fourth alternative project proposed to provide a bundled 10-day peaking service at NCNG's city gate interconnection with Transco at a fixed cost approximately 1.2% lower than Pine Needle's projected fixed cost. NCNG determined that the variable cost of the bundled service would be higher than Pine Needle, resulting in a higher overall cost.

As a fifth alternative, NCNG considered a project contemplated by a partnership of interstate pipelines that had announced an open season for a 50-day storage service with delivery to the Transco/CNG Transmission interconnection at Nokesville, Virginia. At a daily contract level equivalent to the level NCNG was considering for Pine Needle, the fixed cost for this project was $4.142 million per year.

All of these off-system projects--like Pine Needle--would require additional costs to move the volumes from the NCNG/Transco interconnection to points on NCNG's system where the volumes are needed, either through the Cardinal project or improvements to NCNG's system. NCNG determined that none of the off-system alternatives was more cost-effective than Pine Needle for meeting NCNG's projected peak day requirements.

The partnership of pipelines proposing the fifth alternative also proposed a project that would include an LNG facility near the North Carolina/Virginia border, a pipeline connecting the LNG facility to the Raleigh area, and ultimately a pipeline connection with existing interstate pipelines in central Virginia. NCNG determined that this proposed project would have no cost advantage over Pine Needle. Initially, this proposal would have depended on excess summer capacity in the Transco South Virginia lateral to fill the LNG facility. Eventually, the connection with additional interstate pipelines would have given NCNG direct access to new interstate suppliers, and would have provided off-peak capacity into the center of NCNG's system. However, until such link was built, such off-peak capacity would have required an expansion of capacity on the Transco lateral at some additional expense. NCNG concluded that Pine Needle would have a higher probability of going on line on the date NCNG needed the service. NCNG's assertion that Pine Needle was more likely to come on line when needed than other off-system options was unrefuted. No party contended that NCNG acted imprudently in electing to receive service from Pine Needle rather than selecting any of the off-system alternatives.

NCNG witness Davis discussed the on-system alternative to Pine Needle considered by NCNG. NCNG considered expansion of its Barragan LNG storage site at Bentonville. Expanding Barragan would have cost approximately $600,000 per year less than the Pine Needle/Cardinal LNG arrangement. However, NCNG determined that NCNG still should commit to Pine Needle due to a number of considerations offsetting the cost differential in favor of a Barragan expansion.

One benefit of the Pine Needle/Cardinal option compared to the option of expanding Barragan was that the Pine Needle/Cardinal option gave NCNG additional physical capacity to bring additional volumes of gas into NCNG's system in the future to better serve industrial and municipal customers. While NCNG's initial firm capacity on the Cardinal Extension is limited to 40,000 mcf per day to coincide with a 10-day peaking arrangement from Pine Needle, NCNG has capacity on Cardinal to bring 65,000 mcf per day into its system of which 25,000 mcf per day would be on an interruptible basis.

NCNG determined that it should reserve its option to be able to expand Barragan because off-system options are not always available when NCNG's LNG needs arise. Once NCNG expands Barragan, the on-system option no longer will be available.

CUCA argued in its May 25, 2000 brief that NCNG imprudently incurred $300,000 during the test year because the Company contracted to purchase storage capacity from Pine Needle--beginning in the middle of the test year–rather than expand Barragan. In response to this allegation, NCNG first asserted that there was a jurisdictional dispute as to whether this Commission can address the prudency of NCNG's selection of Pine Needle because NCNG acquires gas from Pine Needle pursuant to a FERC-approved rate schedule. CUCA argued "the fact that FERC-approved rates may be reasonable[1] does not mean that a decision to purchase service from a FERC-approved project is prudent if other feasible alternatives are available at a materially lower price."

This Commission understands very clearly that, once interstate rates are established by the FERC, it has no authority to challenge those rates. However, NCNG went a step farther, arguing that this Commission has no authority to even examine the prudency of NCNG's choice of the Pine Needle project. NCNG argued that the FERC Order issued April 30, 1996 in Docket Nos. CP96-52-000 and CP96-134-000 showed that the FERC examined the shipper contracts for the Pine Needle project, including the contract with NCNG, in order to determine that a need existed for this project and that the project was in the best interest of the public. NCNG cited *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 101 L.Ed.2d 322, 108 S.Ct. 2428 (1988), to support this contention. In that case, the U.S. Supreme Court found that FERC-approved agreements requiring an electric utility to purchase 33% of the output of a nuclear unit cannot be examined within a state rate proceeding to evaluate the prudence of the decision to purchase. This Commission sharply disagrees with NCNG's reasoning.

Mississippi Power & Light Co. v. Mississippi dealt with a decision by the Mississippi Public Service Commission in which that Public Service Commission (PSC) ruled that Mississippi Power & Light (MP&L) was imprudent for investing in the Grand Gulf nuclear plant, which had been constructed by an affiliate of MP&L's corporate parent, Mid-South Utilities. The Mississippi Supreme Court upheld the Mississippi PSC's ruling, holding that the preemptive effect of FERC jurisdiction turned on whether the FERC actually evaluated the prudence of MP&L's decision. But the U.S. Supreme Court reversed that, stating that the Mississippi Supreme Court was in error and that whether or not the FERC specifically examined the prudency of MP&L's decision, the state PSC had no authority to make such a ruling.

On the surface, this case would appear to support NCNG's position that this Commission cannot rule on the prudency of NCNG's interstate capacity decisions. However, the fact situation in the *Mississippi Power & Light* case is quite different from that present here. The relationship between federal and state authority under the Federal Power Act (FPA) and the Natural Gas Act (NGA) is not identical. Under the FPA, the FERC actually ordered MP&L to purchase power from Grand Gulf. Under the NGA, the FERC did not order NCNG to participate in Pine Needle; it simply examined the customer commitments Pine Needle had received to ensure that there was a need for the project. The FERC never considered whether or not NCNG had other, better options. That is

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[1] As an aside, this Commission notes that CUCA's suggestion that the FERC found that Pine Needle's rates were "reasonable" is technically incorrect. Docket No. CP96-52 was an application for certificate authorization pursuant to Section 7(c) of the Natural Gas Act. In such a docket, FERC finds "public convenience and necessity" for a new project. Technically, rates are not found to be "just and reasonable" by FERC until the party's rates are changed under Section 4.

the job of this Commission. The Mississippi PSC had originally approved MP&L's participation in Grand Gulf and both MP&L and the Mississippi PSC participated in the proceedings before the FERC. The PSC's subsequent decision to find that MP&L's decision to participate in Grand Gulf was imprudent challenged the FERC's FPA authority and did not withstand scrutiny. But here, the North Carolina Utilities Commission did not approve NCNG's contract for capacity from Pine Needle, FERC did not order NCNG to contract for capacity and this Commission is not challenging the FERC's authority under the Natural Gas Act.

Furthermore, the Commission notes that, in an earlier docket, NCNG joined in an argument that this Commission should review the prudency of a gas local distribution company's (LDC's) decision to participate in given interstate pipeline projects in annual gas cost prudency review proceedings like this one. The North Carolina statute that established annual gas cost prudency reviews (G.S. 62-133.4(c)) was part of the 1991 Gas Expansion Law. That same law allowed the Commission to redefine the word "cost" for purposes of purchased gas adjustment (PGA) proceedings to include interstate demand charges such as those from Pine Needle (G.S. 62-133.4(e)). The Commission exercised that authority in Docket No. G-100, Sub 58. In that docket, the LDCs, including NCNG, argued that "costs" should be redefined so that the LDCs would be allowed to flow through incremental interstate pipeline and storage costs in PGA proceedings rather than having to wait for their next general rate case. The LDCs contended that such a policy would encourage them to acquire the additional capacity needed to support expansion. The Commission accepted the LDCs' position. At no time during that proceeding did NCNG question the Commission's authority to rule on the prudency of interstate capacity additions. In fact, in the January 6, 1992 hearing in that docket, counsel for Piedmont Natural Gas and NUI NC Gas, stated, among other things, that gas purchasing prudency had to be determined in the annual gas cost review. Without such a review, the LDCs would face the prospect of passing through incremental interstate demand charges one year and then having to wait until the next rate case to find whether or not their capacity decision would be considered prudent. Counsel for NCNG subsequently stated that NCNG agreed with all of the arguments made by counsel for Piedmont Natural Gas and NUI NC Gas. So it would appear that NCNG, having supported an argument that the Commission must review--in proceedings like this one--the prudency of interstate capacity purchasing decisions which result in incremental demand charges, now wants to deny that the Commission has any authority over such decisions.

The Commission concludes that the Court's ruling in *Mississippi Power & Light Co, v. Mississippi* does not preclude us from examining the prudency of the agreements entered into by North Carolina LDCs to purchase capacity from given interstate providers. Clearly, the North Carolina Commission cannot overturn a rate approved by the FERC. But CUCA is correct in asserting that the Commission can question whether the LDC chose the best project.

CUCA's argument that Pine Needle was not cost-justified focused on the comparison between the Pine Needle project and the on-system option of expanding the Barragan plant. In order to make its case, CUCA discounted the reasons memorialized by NCNG in 1995 and testified to in 2000 in support of NCNG's decision except one - the FERC, which would establish the rate of return on Pine Needle, might allow a higher return than this Commission, which would set the rate of return on Barragan. NCNG responded that this was speculation.

CUCA dismissed most of NCNG's cost comparisons because they compare the cost--and benefits--of the Pine Needle and the Cardinal projects in tandem with the costs of the on-system option. CUCA asserted that "the Cardinal project could have been constructed independent of the Pine Needle project." The Commission recognizes that all of the off-system peak storage options--including Pine Needle--required either the construction of the Cardinal project or the expansion of NCNG's system in order to deliver gas to NCNG's customers. It would be improper to compare any of the off-system options to the Barragan on-system option without including the delivery costs of the off-system project. And by the same token, it is also reasonable to consider the advantages of an option that requires additional pipeline capacity into the center of NCNG's service territory. No evidentiary predicate exists permitting CUCA--when making the comparison to Barragan--to view Pine Needle "stripped of the benefits associated with the Cardinal project."

CUCA's dismissal of NCNG's primary reason for contracting with Pine Needle rather than expanding Barragan--to reserve the on-system option for a time when an off-system option may be unavailable--is also not supported by a convincing argument. The justification for NCNG's decision is supported by the evidence produced by NCNG at the hearing. The evidence in this case is that interstate capacity projects, including off-system storage projects, are built in a cyclical pattern, leaving periods of years when options for new capacity are limited or nonexistent. CUCA dismissed this testimony by stating that "NCNG's unverified speculation about the potential that there might be no storage projects available in the future is not based upon any study and appears inconsistent with the fact that in 1995 when Pine Needle was considered, 11 different storage projects and variations of projects were available to NCNG." The Commission notes that it is not appropriate to count variations of projects; NCNG did not have 11 different projects available in 1995. NCNG witness Davis testified that, at the present time, he knew of only two options to meet NCNG's projected need for storage capacity in 2003 or 2004. One was Barragan and the other was additional storage in the Pine Needle project. NCNG's argument that it was prudent to reserve the Barragan option for a later date was compelling. Furthermore, Mr. Davis testified that NCNG expected that it would sell at least one and a half to two million dekatherms of additional gas to industrial customers by having the Cardinal Pipeline available. Revenue from those sales would more than meet the break-even transportation rate for the Cardinal project.

The standard for determining the prudence of NCNG's decision to contract with Pine Needle for the needed storage capacity is that its decision must have been made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or should have been known at that time. See Order in Docket No. E-2, Subs 537 and 333 dated August 5, 1988, 78th Report NCUC Orders and Decisions, 238, 251 (1988) citing *State ex rel. Utilities Commission v. General Telephone Co.*, 281 N.C. 318, 345, 189 S.E.2d 705, 722 (1972). NCNG is not required to choose the least cost option when other considerations suggest that another decision is prudent and reasonable.

After reviewing the evidence offered by NCNG explaining its peaking needs and the process the Company followed to examine alternatives, the Commission concurs with NCNG that it acted prudently in selecting Pine Needle as the appropriate project to meet the anticipated storage needs. No evidence was offered to contradict NCNG's evidence. That evidence shows that NCNG began planning well in advance of the point in time when new storage capacity would be needed and considered a range of different options. There is no dispute that the LNG storage capacity was needed. Among off-site options, Pine Needle was no more costly than other potential options and less costly than nearly all the others. In looking at cost differences, NCNG looked beyond unit costs to consider both fixed and variable costs and the differences in services offered. NCNG determined that the Pine Needle had a high probability of being built at forecast cost and of coming on line when NCNG needed the capacity. Pine Needle capacity would be available through Cardinal at a point on NCNG's system where NCNG needed it the most. Finally, the Pine Needle capacity was available for and priced to fit NCNG's needed peaking requirements. While expansion of the on-system Barragan facility was less costly, this option remains available for future storage needs and provides NCNG needed flexibility to add storage capacity when reasonably priced off-system options may not be available. Looking at the totality of the circumstances, the Commission concludes that NCNG acted prudently.

Although the Commission concludes that NCNG's decision to contract with Pine Needle for storage capacity was prudent, it nevertheless must express concern over one issue. NCNG has contracted for capacity with an entity in which, through an affiliate, it has an equity interest. Furthermore, NCNG's affiliate is a partner with Transco, its major interstate capacity provider.

Commissioner Ervin noted during the hearing that Pine Needle's rates were set by the FERC and asked NCNG witness Davis what the Company's plans were to keep rates at Pine Needle as low as possible. Mr. Davis' response was that the FERC rates were "cost-based." Aside from the fact that differences of opinion can and do occur over whether a particular set of rates are cost-based, Mr. Davis' comment begs the question of whether NCNG would actively seek to maintain reasonable "cost-based rates." Even if the rates which were originally established for Pine Needle were appropriately cost-based, the appropriateness of those rates could well change over time.

In FERC Docket No. CP96-52-000, one issue raised by this Commission was whether Pine Needle would rest on its initial "cost based" rates as its rate base declined. In exchange for withdrawing an appeal, this Commission negotiated an agreement for Pine Needle to come in for a rate case at a set point in the future. Without that agreement, Pine Needle, with its high capital cost and relatively low operating costs, would reasonably have been quite content to collect its initial "cost-based" rates far into the future, freezing the same rate base and income even as annual depreciation ate into its net plant. The Commission notes that the record in that FERC docket shows that NCNG sat silently by while hard questions asked by this Commission went unanswered by Transco, the Pine Needle operating partner.

Witness Davis added that the Commission intervened in the hearing to "set Pine Needle's rates," "so . . . there's an opportunity there to be a participant in setting those rates." The Commission is well aware that it can intervene in FERC cases. The question is whether NCNG will intervene on behalf of its ratepayers to keep Pine Needle rates as low as possible.

When asked whether he was aware that there was a rate increase related to Pine Needle's electric costs pending before the FERC and, if so, did he know what action NCNG planned to take with respect to that rate increase, Mr. Davis responded that he was not aware if NCNG was taking action or not. This response is of concern to the Commission, which expects NCNG and other LDCs to vigorously protect the interests of their ratepayers in FERC proceedings. Mr. Davis' assertions that Pine Needle's rates are "cost based" and that this Commission can take its "opportunities" to participate in setting Pine Needle's rates do not relieve NCNG of the responsibility to ensure that its

Pine Needle costs are as low as possible. Furthermore, there should be no question of whether NCNG's new business relationship with Transco will alter NCNG's participation in Transco's proceedings before the FERC. The Commission wishes to make clear that it intends make use of NCNG's annual gas cost prudency reviews, as well as other proceedings, to scrutinize NCNG's behavior in future Pine Needle and Transco's proceedings before the FERC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT 16

The evidence and conclusions for this finding of fact are contained in the testimony and exhibits of NCNG witnesses Davis and Monaghan and Public Staff witnesses Kibler and Davis.

CUCA asked many questions of NCNG's witnesses at the April 11, 2000, hearing implying that NCNG transferred gas to its subsidiaries, NC Energy and Cape Fear, at prices below the cost of gas that NCNG sought to pass through to its ratepayers and recover through rates. CUCA offered no affirmative evidence that NCNG favored its subsidiaries through the establishment of favorable transfer prices.

In its brief submitted May 25, 2000, CUCA accused NCNG of transferring gas to its affiliates at prices "below cost," of maintaining accounting records that are questionable and unreliable, of failing adequately to document subsidiary transactions, and, in effect, of circumventing Commission orders requiring that ratepayers be credited with 75% of the net compensation from secondary market transactions. CUCA accused the Public Staff of failing to fulfill its duties to audit NCNG's books and protect the interests of ratepayers and instead of rubber stamping the Company's requests. As its remedy for all the abuses CUCA claimed to have uncovered, CUCA asked in its May 25, 2000 brief for refunds of all of the net compensation from the affiliate sales not previously credited to ratepayers under the Commission's Order on Secondary Market Transactions in Docket No. G-100, Sub 57. Specifically, CUCA asked for the sum of the amount calculated using the difference between the ratepayer purchase price and the Station 65 price (a total of $220,277) and the amount calculated using the difference between the Station 65 price and the affiliate transaction price (a total of $91,406), for a total of $311,863. Alternatively, CUCA asked for at least the $91,406 derived from the alleged difference between the Station 65 price and the affiliate transfer price.

In its September 28, 2000 brief, CUCA's remedy was modified. CUCA maintained that, "NCNG's failure or refusal to memorialize transactions . . . obligates NCNG to refund to its ratepayers the differential between an appropriate gas transfer benchmark and the price that NCNG assigned to its affiliates." CUCA contended that the benchmark should be either the marginal (spot) cost of NCNG's system gas (with any remaining gas transferred to the marketing affiliates at the price of the most expensive long-term contracts) or the average cost of NCNG's system gas.

The Commission determines that no remedy is warranted as CUCA advocated because, as discussed below, the factual predicate for the CUCA-sponsored remedy does not exist. No justification exists for the accusation that NCNG transfers gas to its subsidiaries at "below costs."

NCNG presented testimony and exhibits that clearly indicate that in limited circumstances with respect to limited volumes on limited occasions NCNG may be able to purchase gas that is then transferred to an affiliate for resale at a cost below NCNG's average cost to resell gas to its ratepayers for the particular month. The evidence does not support the contention that NCNG unlawfully reduced the transfer price to its subsidiaries below the cost NCNG incurred to acquire the gas.

In questioning NCNG's affiliate transfer price, CUCA first compared the cost of gas charged to ratepayers with the cost charged to the NCNG affiliates on an annual basis. In its May 25, 2000 brief, CUCA contended that "NCNG's schedules indicate that ratepayers were charged $2.31 on an average cost basis but were credited with only $2.10 or less on an average cost basis if the dekatherm was transferred to an NCNG affiliate." The $2.31 average cost for the test year computed by CUCA's counsel is the average unit cost incurred by NCNG for all volumes purchased, and related commodity transportation charges, including gas that became part of system gas supply, gas transferred to affiliates, gas used in system operations, and gas added to storage. NCNG ratepayers were not charged with volumes transferred to affiliates or volumes added to storage and remaining in storage as of the end of the test year. The Commission concludes that CUCA's attempt to take an average cost for the entire test year--which includes the cost of gas for storage injections--and the average affiliate transfer price for the entire test year and draw inferences about the appropriateness of the affiliate transfer price is misleading because the affiliate transfers were not distributed evenly throughout the test year. The only valid comparisons are comparisons of the affiliate transfer price to the actual cost of the gas in the specific months when the transactions occurred, and comparisons of the transfer price to the price offered to other, non-affiliated parties.

The evidence elicited at the hearing showed that there are differences in the monthly prices of gas transferred to affiliates from the costs of gas NCNG recovered from its ratepayers. However, these differences were readily explained by the NCNG witnesses.

A major difference in monthly prices was explained by the location at which gas was purchased for affiliates and ratepayers. With minor exceptions, NCNG transferred gas to its two marketing subsidiaries at Transco's Station 65 (Station 65) in Louisiana. In contrast, the gas charged to ratepayers through NCNG's tariffed rates was delivered to NCNG's city gate in North Carolina and therefore included the added costs of transporting the gas from Station 65 to North Carolina. NCNG witnesses testified that the cost of this transportation ranged from 13 to 17 cents per dekatherm. This 13 to 17 cents differential between the transfer prices charged to subsidiaries and the costs NCNG recovered through rates is equivalent to that set forth in NCNG's schedules offered into evidence in this docket.

CUCA contended that the affiliate transfer prices were, in some months, lower than the Station 65 price. CUCA's Table 1 on page 9 of its May 25, 2000 brief purported to show that the affiliate transfer price was understated in six of the twelve months of the test year because the average cost of all supplies purchased, after subtracting the volumes transferred to subsidiaries, exceeded the affiliate transfer price by more than the variable commodity cost of transporting gas from Station 65 to NCNG's city gate. NCNG argued that its gas supply does not all come from a single source at a single price, and that true-ups and adjustments are routinely booked to NCNG's gas costs as part of the monthly accounting cycle and therefore, CUCA's analysis was flawed.

CUCA's Table 2 in its May 25, 2000 brief showed four months (April, May, July and September) in which the affiliate transfer price appeared to be lower than *Inside FERC's* Gas Market Report Transco Station 65 index price. The affiliate transfer prices shown in Table 2 were taken from CUCA Monaghan Cross-Examination Exhibit 11. The Commission concurs with CUCA's premise that the *Inside FERC* index is a valid standard for valuing affiliate transfers at Station 65 in most circumstances because a significant part of NCNG's supply is priced on the basis of that index. However, two significant errors in data provided to CUCA by NCNG resulted in confusion.

The difference between the Station 65 index price and the affiliate transfer price in the month of April is explained by the first of two errors in NCNG's data provided to CUCA. CUCA Monaghan Cross-Examination Exhibit 11 is taken from a set of corrected gas cost detail worksheets that were prepared by NCNG to support correcting entries NCNG agreed to make as a result of the Public Staff's review of NCNG's gas cost accounting during the test year. The document provided to CUCA in discovery included a sheet that was mislabeled "Worksheet for April, 1999 Gas Cost Estimate," but was actually an uncorrected copy of the same sheet for March 1999. NCNG later determined that the mislabeled sheet had been included in the sheets provided to the Public Staff, and that no adjustment to the affiliate transfers for April was required. NCNG inadvertently overlooked the fact that a copy of the mislabeled sheet had been provided to CUCA in discovery, and therefore failed to notify CUCA that the sheet had been included in error. The April transfer price shown in CUCA Monaghan Cross-Examination Exhibit 11 is the March price inadvertently carried forward. The actual affiliate transfer price for April was the *Inside FERC* index price for that month.

A second error explains the difference between the Station 65 index price and the affiliate transfer price in the month of May. A transposition error on a work sheet significantly overstated the affiliate transfer price.

CUCA conducted a four-hour deposition of John Monaghan whom NCNG provided as a 30(b)(6) witness to respond to CUCA discovery requests on information provided in Appendix A to NCNG's June 12, 2000 reply brief. CUCA maintained that gaps still existed in NCNG's explanation as to why the NCNG transfer prices to affiliates in the months of May, July and September 1999, are below the Station 65 first-of-the-month index price. Mr. Monaghan testified that the lower prices to affiliates in these months reflected lower than beginning-of-the-month priced spot purchases from certain NCNG suppliers. NCNG provided invoices from these suppliers showing the lower prices. CUCA maintained that NCNG failed to prove that these NCNG purchases were appropriately matched to sales that Cape Fear or N.C. Energy made to one of its industrial customers.

Mr. Monaghan was unable to provide evidence at the deposition to satisfy CUCA that the NCNG mid-month purchases at below first-of-the-month index prices went to fill NCNG marketing affiliate orders because NCNG accounted for the costs and volumes of sales to affiliates at the end of the month by subtracting the costs and volumes of affiliated sales that were not made through NCNG from total sales by the affiliate.[1] The difference, if any, was attributed to the mid-month spot purchases. Mr. Monaghan did not have at the deposition copies of the contracts between NCNG marketing affiliates and its purchasers or the accounting data base that would have satisfied CUCA. NCNG did not rely upon this information in preparing its reply brief, and NCNG operated on the understanding that the post hearing discovery was to address new evidence contained in the reply brief. This was a correct understanding of the reason that the hearing was reopened.

In its May 25, 2000 brief, CUCA included an excerpt from the transcript that purported to show that NCNG witness Monaghan acknowledged that NCNG had transferred volumes to affiliates below cost at Transco's Station 65 in certain circumstances. CUCA again referred to "Mr. Monaghan's admission of below cost sales" at the top of page 12. The line of questioning leading up to the excerpt included in the CUCA brief refers to the monthly *Inside FERC*'s Gas Market Report's Transco Station 65 index price. The response from NCNG witness Monaghan refers to circumstances in which the affiliate transfer price at Station 65 might be lower that the monthly *Inside FERC* index price. Contrary to CUCA's contentions, Mr. Monaghan never testified that the transfer price would be lower than NCNG's cost.

The record in this docket shows no evidence that NCNG favored its affiliates when purchasing gas. NCNG effectively explained that the difference between the ratepayer purchase price and the affiliate transfer price was largely accounted for by the fact that the affiliate transfers occur mostly at Station 65 and the ratepayer price reflects the 13 to 17 cents transportation costs to North Carolina. That left the issue of whether the affiliates received favorable treatment at Station 65. NCNG explained that not all transactions occurred at Station 65 and not all of the Station 65 transactions were priced at the first-of-the-month *Inside FERC* index price. When NCNG's two errors are corrected, there were three months in which the amounts calculated using affiliate transfer prices exceeded the amount based on the Station 65 price and one month--November 1998--in which the affiliate prices actually led to higher costs for NCNG's affiliates. The Commission also notes that, in the three months in which affiliate transfer prices were below the Station 65 index price, the total volume of affiliate transactions was small and, when multiplied by the difference between the transfer price and the Station 65 price and then multiplied by the 25% that NCNG is allowed to retain under Commission secondary market transaction rules, the total amount gained by the Company in those months was less than $4,000. The small size of the amount in question strongly suggests that no improper cost shifting occurred. Summing all four monthly figures, the affiliates actually paid a very small amount more than they would have if Station 65 prices had been used in all cases. On page 24 of its September 28 brief, CUCA suggested that the Commission discard the excess amount paid in November 1998, stating "CUCA assumes that the 1 cent price differential is simply due to rounding

[1] Mr. Monaghan testified in the deposition that the NCNG employee who would have purchased the gas on behalf of the NCNG marketing affiliate, Paul Lawing, was the same person who would have purchased the gas from the suppliers and would have been the person with the first-hand knowledge of the timing of the supplier purchases and the timing and identification of the buyers for the sales by the NCNG affiliates to the industrial customers. However, Mr. Lawing was not employed by NCNG at the time of the deposition.

by NCNG." In calculating this excess, there are two numbers that could have been affected by rounding: the Inside FERC Station 65 Index Price could have been rounded down and the calculation of NCNG's affiliate transfer price could have been rounded up. The Inside FERC Station 65 Index Price is what it is; there is no evidence to indicate that the Index was rounded down in November. Simple math using data obtained by CUCA reveals that the affiliate transaction price calculation was rounded down, not up. The Commission concludes that no probative evidence was elicited at the hearing that NCNG favored its marketing affiliates at Station 65.

With the above differences explained, CUCA turned to an attack on NCNG's accounting. CUCA charged that NCNG's books are unreliable and that NCNG refrained from documenting affiliate transfers.

The Commission does not accept CUCA's broadside accusations that NCNG's books of account are unreliable and unworthy of the Commission's trust. CUCA did not examine or audit NCNG's books of account. CUCA examined schedules in which NCNG has transferred information from its books in an effort to present data in a form required by the Commission. In addition, NCNG presented schedules, summaries and portions of its base documents through discovery. Some errors exist in the documentation. However, no evidence supports CUCA's allegations of widespread or systematic unreliability in NCNG's books of account. Errors may temporarily exist in NCNG's books. However, each year the books are closed, reconciled and audited. Errors are rectified and corrections are made. The records are audited and certified that they comply with generally accepted accounting principles if they do and not certified if they do not. In addition, the Public Staff audits the books and records to ensure compliance with appropriate ratemaking procedures. The Public Staff witnesses testified in this docket under oath that they conducted the audit and that the records complied with the Commission's requirements. The witnesses also testified that they found errors that they required NCNG to correct. As a result, the Commission cannot conclude that NCNG's accounting records are inherently deficient or contain evidence of improper affiliate transactions.

CUCA also asserts that NCNG made a decision to refrain from documenting interaffiliate commodity transfers. During cross-examination CUCA inquired into the existence of <u>summary</u> memoranda or contracts that could be used to <u>verify</u> costs and prices. The NCNG witnesses testified that such summary documents were unnecessary. No testimony exists, as CUCA claims, that affiliate commodity transfer transactions went undocumented. CUCA's own argument undercuts its allegations: "The only information available to review and evaluate NCNG's affiliate transfers and determine whether ratepayers were properly credited are NCNG's own accounting records."

CUCA argues in its May 25, 2000 brief that NCNG witness Monaghan conceded that "NCNG's own schedules" do not distinguish between gas to be used by ratepayers and gas to be transferred to affiliates "in providing a total incurred commodity cost." The line of questions from CUCA's counsel refers to <u>specific lines</u> labeled "Total Commodity Costs Incurred" and "Total Purchases (DTs)" on two of the schedules in Hering Exhibit 1. A review of the transcript however, reveals that Mr. Monaghan testified that the specific lines on the schedules referred to by CUCA's counsel do not distinguish between gas purchased for system supply, gas transferred to affiliates and gas purchased for storage injections. Mr. Monaghan went on to state that the bottom lines of the schedules very clearly show the volume and cost of gas that was charged to ratepayers as part of system gas supply.

Witness Monaghan also noted that the specific schedules in question were prescribed by the Public Staff for use in the annual review proceedings of all the North Carolina LDCs, and therefore they are not "NCNG's own schedules."[1] Mr. Monaghan did not concede that the schedules treat "both city-gate purchases and affiliate transfers as an 'apples to apples' comparison." In fact, Mr. Monaghan stated "there are all sorts of apples and oranges in this schedule but the bottom line is the value of the gas that actually came onto NCNG's system and was sold to customers."

The Commission determines that CUCA has failed to justify any remedy. No evidence exists that NCNG conveyed gas to affiliates at below costs or refused to maintain adequate records. NCNG has credited ratepayers with 75% of the difference between the subsidiaries' costs and the price the subsidiary received for the gas. In its order of December 22, 1995, in Docket No. G-100, Sub 67 the Commission required each LDC to record 75% of the net compensation received from secondary market transactions in the PGA deferred account. Net compensation is defined as the gross compensation received by an LDC from the secondary market transaction less the transportation charges, taxes and other costs, including all costs incurred by the LDC in connection with the purchase of the gas directly related to the transaction. In the case of secondary market transactions between an LDC and its affiliate, "gross compensation" shall not be less than the gross compensation received in connection with the same or similar transactions between the LDC and non-affiliated parties. NCNG correctly has complied with the Commission's order.

NCNG met its burden of proof by showing that NCNG incurred the gas costs it did during the test year. Additional evidence in support of recovery of the gas costs in question was provided by Public Staff witnesses who testified that the costs were reasonable and prudent. CUCA has failed to challenge the reasonableness and prudence of the costs with any affirmative evidence elicited through the testimony of its own witness or on cross-examination of witnesses sponsored by other parties. CUCA's comparisons of costs were invalid and based on unsupported assumptions. After two abortive attempts to show that NCNG has favored its affiliates, CUCA was left in the end only with an argument that gaps exist in the proof NCNG has provided showing that CUCA's second set of comparisons for two months are inaccurate.

The Commission concludes that NCNG did not unreasonably favor its affiliates. The Commission is, however, concerned about a number of problems which arose during consideration of this issue. Although CUCA had a right to attempt to make its case on cross-examination of witnesses sponsored by other parties and is not required to tell the Commission what it hopes to establish on cross-examination prior to the hearing, the manner in which CUCA eventually presented its recommendations to the Commission and NCNG's witness' decision to accept certain information presented for the first time on cross subject to check made it necessary to reopening the hearing. The

[1] The Commission notes that, while the Public Staff may have recommended the format of these schedules, the Commission prescribed them.

Commission would have had an easier time resolving the issues raised in this case if CUCA had disclosed its contentions earlier in the process.

Errors in material given to CUCA in discovery made counsel for CUCA's job considerably more difficult. Both those errors had not been detected at the start of the April 11, 2000 hearing and both strengthened CUCA's suspicions that NCNG was unfairly favoring its affiliates.

The Public Staff's presentation left the Commission somewhat uncertain about the extent of the Public Staff's own investigation. From the testimony of Public Staff witnesses Kibler and Davis, it cannot be established whether they actually examined the books of account to determine the manner in which affiliate transfers were priced. Mr. Kibler was asked on cross-examination what documents were reviewed ". . . in determining whether the Company's accounting is appropriate . . ." His response--as it relates to this issue--included a reference to sources listed in his pre-filed testimony which included "gas supply contracts and responses to Public Staff's data requests." Mr. Davis, who was the Public Staff witness who testified on the prudence of NCNG's gas purchases, testified that he reviewed gas supply contracts, and also submitted data requests, ". . . containing questions relating to NCNG's gas purchasing philosophies, customer requirements, pricing determinates, and gas portfolio mixes." Although Mr. Davis testified that NCNG's gas costs were prudently incurred, it is not clear to the Commission how deeply the Public Staff delved into the question of affiliate transfer pricing. When asked about the sale of gas to affiliates at a price that was below market, Mr. Davis testified that he was aware of such a circumstance, but in another proceeding and dealing with the transfer of gas at a point other than Station 65. But when asked, "So there are no situations that you are aware of in which NCNG has transferred gas from itself to its subsidiary at a cost less that NCNG paid?" (a premise that the Company questioned), Mr. Davis responded, "There may be, sir, but I'm not aware of any specifics on that."

The Commission urges all parties to work together to see if complex issues such as those which have arisen in this proceeding could be presented with greater clarity in the future.

In its September 28, 2000 brief, CUCA recommended that the Commission order NCNG to take certain actions to ensure that affiliate transactions are more clearly documented and also asked that NCNG modify the schedule designed by Public Staff on which NCNG reports its test period commodity gas costs in annual reviews to segregate the costs and credits associated with direct subsidiary transfers. Affiliate transactions raise issues of considerable concern to the Commission. Information concerning this issue should be clear and readily available. The Commission encourages NCNG to improve its documentation of such transactions in the future. CUCA's recommendations came in its final brief and therefore other parties had no opportunity to comment on them. Also, the Commission notes that NCNG's gas purchasing function has been shifted, changing the circumstances. NCNG's next Annual Review of Gas Costs has been opened in Docket No. G-21, Sub 409. The issues raised by CUCA can best be addressed in that docket.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT 17 AND 18

The evidence for these findings of fact is found in the testimony of NCNG witness Hering and Public Staff witnesses Davis and Kibler and in the records of the Commission.

Several arguments and issues were presented concerning certain long-term transportation contracts that NCNG entered into with industrial customers. The contracts in question were with customers Wiccacon, Easco-Ahoskie and Easco-Winton. These transportation contracts contained negotiated rates agreed to by NCNG to retain the customers on system and avoid bypass. In NCNG's 1998 prudency review in Docket No. G-21, Sub 368, the Public Staff first notified the Commission that it was investigating these contracts and that it would ask the Commission in a future proceeding to consider how such contracts should be handled. The Commission acknowledged this in its order in that docket, and all parties therefore had notice of the issue. These contracts were the subject of discussions held between the Public Staff and NCNG in connection with the 1999 prudency review in Docket No. G-21, Sub 374. As a result of those discussions, no issues were presented in the 1999 docket. The issues presented in this docket are as follows.

During the review period in this docket, NCNG made an accounting adjustment to credit $167,761 to its deferred account in connection with the long-term transportation contract with Wiccacon. Wiccacon, which has now gone out of business, first became a customer of NCNG in 1994 or 1995 before the conclusion of the hearing in NCNG's last general rate case. In discussions with NCNG, the Public Staff took the position that a non-representative level of Wiccacon volumes and revenues was reflected in the cost of service calculations in the general rate case and that it would therefore be inappropriate to flow through the deferred account the full level of the discount that Wiccacon enjoyed under the negotiated rates in its contract. The Public Staff and NCNG agreed that NCNG would credit S167,761 to the deferred account, representing Wiccacon discounts taken in the past. They proposed no adjustments with respect to the Easco contracts, but they agreed that NCNG would file the Easco contracts with the Commission. NCNG had taken the position that paragraph 4 of Rider B of its tariffs authorized it to negotiate such contracts and that no additional approval was needed, but, in spite of this belief, NCNG agreed to file the agreements "for inspection." The agreements were filed in Docket G-21, Sub 380 on May 12, 1999. The filing provided for the Easco contracts themselves to remain under seal, but the filing was a matter of public record. The Commission authorized NCNG to serve Easco pursuant to the contracts by order of September 17, 1999.

The first issue relates to the $167,761 deferred account adjustment in connection with the Wiccacon contract. The Commission concludes that the $167,761 adjustment is appropriate, for the reasons cited above, and should be approved.

The next issue concerns approval of the Easco contracts. During the test period and prior to Commission approval, NCNG charged approximately $900,000 in negotiated losses on the Easco contracts to all of its customers through deferred account treatment. CUCA argues that the Commission should not allow NCNG to recover the discounts that were incurred prior to Commission's approval of the contracts in September 1999. CUCA relies upon G.S. 62-138(a), which states that utilities must "file with the Commission all ... forms of service contracts used or to be used...," and Commission Rule R6-5(2), which states that LDCs must file with the Commission a "copy of each special contract for service." CUCA also cites prior Commission practice as requiring that transportation contracts with negotiated losses be filed for approval. NCNG relies upon paragraph 4 of Rider B of its approved tariffs, which provides as follows:

> The Company may negotiate with commercial and industrial customers on its sales and transportation rates to avoid the loss of deliveries to these customers. All margin loss from these customers excluding all PSVA volumes as defined in Rider A shall be charged to the Deferred Gas Cost Account. Such margin loss shall be based on the Company's tariff rates, exclusive of temporary increments and decrements.

NCNG argues that it is "far from clear" that prior approval of the contracts, other than that already provided by Rider B, was required. NCNG says that G.S. 62-138(a) does not apply since these contracts were unique, not form contracts, and that Rule R6-5(2) neither requires special contracts to be filed prior to execution nor requires Commission approval of such contracts prior to service thereunder. NCNG says that prior Commission practice with other LDCs does not apply since no other LDC has tariff language comparable to NCNG's Rider B. CUCA also argues that prior approval is needed to ensure compliance with the filed rate provisions of G.S. 62-139 and the anti-discrimination provisions of G.S. 62-140. G.S. 62-139 prohibits utilities from charging rates other than those approved by the Commission. G.S. 62-140 prohibits the charging of unlawfully discriminatory rates. NCNG responds that when the Commission approved Rider B, the requirements of these statutes were met. Finally, NCNG argues that even when a utility fails to obtain prior approval, the Commission has discretion to evaluate the contract and approve it after the fact upon finding the terms reasonable and that that is exactly what the Commission did when it authorized service pursuant to the contracts on September 17, 1999.

The Commission will not approve the deferred account adjustment proposed by CUCA with respect to the Easco contracts. Even if prior approval of the contracts had been required and NCNG had failed to obtain it (which is not decided), the Commission still had discretion to evaluate the reasonableness of the contracts and, if the Commission found them reasonable, to approve them after the fact for ratemaking purposes. See *State ex rel. Utilities Commission v. Intervenor Residents*, 52 N.C. App. 222, 278 S.E.2d 761 (1981), reversed on other grounds, 305 N.C. 62, 286 S.E.2d 770 (1982). The Commission in fact examined the contracts and authorized service under them in September 1999. The Public Staff, after investigating the Easco contracts, recommended no adjustments, and there is no evidence to support an adjustment.

It has long been the practice of NCNG and other LDCs to negotiate rates with industrial customers in order to retain them on the utility system and avoid bypass. In this way, the industrial customers continue to contribute toward a recovery of fixed gas costs. The general body of ratepayers is thus better off with the industrial customers on system. The Commission does not intend to discourage such negotiations. However, in the past there has not been a clearly defined, consistent procedure for handling such negotiations, and the Commission believes that, for the future, procedures for Commission review of negotiated contracts, as hereinafter specified, are appropriate and should be clarified and established.

NCNG's Rider B is not unique. Other LDCs also have tariffs which provide for negotiations with customers and recovery of negotiated losses through deferred accounts. The Commission recently dealt with the appropriate procedure for review of such negotiations in the annual prudency review for Public Service Company of North Carolina, Inc., in Docket No. G-5, Sub 414. In that docket, the Commission issued an order on October 18, 2000, which weighed both the utility's need to respond quickly to a customer's lower alternate fuel prices and the Commission's need for oversight of negotiated rate contracts. The Commission ordered that negotiated sales and transportation contracts of less than one month may be handled through the deferred account without being filed with the Commission. Negotiated contracts of more than one month but less than one year in duration shall be filed within 30 days of execution. There will be no pre-approval, but such contracts shall be on file and subject to review in the next annual prudency review. Negotiated contracts of more than one year shall be filed and shall require Commission approval prior to becoming effective. The Commission concludes that similar procedures should be ordered for NCNG. Copies of contracts filed with the Commission may be redacted as appropriate to protect confidential information.

IT IS, THEREFORE, ORDERED as follows:

1. That NCNG's accounting for gas costs and recoveries during the twelve-month period of review ended October 31, 1999, is approved;

2. That NCNG is authorized to recover 100 percent of its gas costs incurred during the twelve-month period of review ended October 31, 1999, as the same are reasonable and prudently incurred; and

3. That the increments and decrements in NCNG's rates, which are presently in place, remain unchanged until further Order of the Commission; and

4. That in the future, negotiated sales and transportation contracts of less than one month may be handled through the deferred account without being filed with the Commission. Negotiated contracts of more than one month but less than one year in duration shall be filed within 30 days of execution. There will be no pre-approval required, but such contracts shall be on file and subject to review in the next annual prudency review. Negotiated contracts of more than one year shall be filed and shall require Commission approval prior to becoming effective.

ISSUED BY ORDER OF THIS COMMISSION.
This the 19th day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg030901.04

DOCKET NO. G-21, SUB 409

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of North Carolina Natural Gas Corporation 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: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on April 10, 2001, at 9:30 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; and Commissioners Judy Hunt and J. Richard Conder

APPEARANCES:

For North Carolina Natural Gas Corporation:

Edward S. Finley, Jr., Hunton & Williams, P.O. Box 109, Raleigh, North Carolina 27602

Bentina D. Chisolm, Associate General Counsel, CP&L Service Company, LLC/North Carolina Natural Gas Corporation, 411 Fayetteville Street Mall, P.O. Box 1551, PEB 17, Raleigh, North Carolina 27601

For Carolina Utility Customers Association, Inc.:

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

For the Using and Consuming Public:

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

Margaret A. Force, N.C. Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On February 2, 2001, North Carolina Natural Gas Corporation (NCNG or Company) filed the direct testimony and exhibits of Fredrick W. Hering, Supervisor—Rates and Gas Accounting at NCNG; Pamela R. Murphy, Director, Gas and Oil Trading in the Energy Trading Dept., Carolina Power & Light Company; and Terrence D. Davis, Senior Vice President of Operations, NCNG, relating to the annual prudence review of NCNG's gas costs pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On February 27, 2001, the Commission issued its order scheduling a public hearing for April 10, 2001, setting dates for pre-filed testimony and intervention in this docket and ordering NCNG to publish notice of these matters in a form of notice attached to the Commission's order.

On February 21, 2001, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, which was allowed by the Commission on February 27, 2001.

On March 6, 2001, the Attorney General filed notice of intervention.

On April 3, 2001, CUCA filed a motion to compel response to its first data request. On April 5, 2001, NCNG filed a response to this motion. By order dated April 9, 2001, the Commission entered an order denying CUCA's motion to compel.

The Public Staff filed the direct testimony of Julie G. Perry, Supervisor of the Natural Gas Section in the Public Staff's Accounting Division, and Jan A. Larsen, Utilities Engineer of the Natural Gas Section, on March 29, 2001. Neither CUCA or the Attorney General filed testimony in this proceeding.

The hearing was conducted as scheduled. Witnesses Hering, Murphy and Davis for NCNG and witnesses Perry and Larsen for the Public Staff testified.

Based on the testimony and exhibits and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. NCNG is a public utility as that term is defined in Chapter 62 of the North Carolina General Statutes.

2. NCNG is engaged primarily in the purchase, distribution, and sale and transportation of natural gas to more than 173,000 customers in south central and eastern North Carolina.

3. NCNG has filed with the Commission and submitted to the Public Staff 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 test period for review of gas costs in this proceeding is the twelve months ended October 31, 2000.

5. During the period of review, NCNG incurred gas costs of $176,454,978 and recovered $169,279,353 for gas costs through its rates. This resulted in an under-recovery of $7,175,625. NCNG collected $3,031,512 through a rate increment in all sales rates during the review period. NCNG also refunded $1,169,751 to customers using rate decrements during the test year.

6. During the period from November 1999 through October 2000, NCNG generated a net recoupment of fixed costs amounting to $358,981 as a result of capacity release and buy/sell agreements. The Company credited 75% of these proceeds to its Deferred Account - All Customers in order to refund these amounts pursuant to the Commission's order in Docket No. G-100, Sub 67.

7. At October 31, 2000, NCNG had a net debit balance of $15,474,360 in its deferred gas cost accounts, consisting of a debit balance of $11,299,513 in the Commodity Deferred Account - Sales Customers Only and a debit balance of $4,174,847 in the Demand Deferred Account - All Customers.

8. The Public Staff took no exceptions to NCNG's accounting for gas costs and recoveries during the period of review.

9. NCNG has nine transportation and supply contracts with the interstate pipelines that transport gas directly to NCNG's system or term supply contracts with other suppliers.

10. Based on NCNG's contracts with gas suppliers, the gas costs incurred by NCNG during the period of review were prudently incurred.

11. NCNG should be permitted to recover 100% of its prudently incurred gas costs.

12. NCNG should be permitted to recover its storage costs associated with the Pine Needle LNG Company LLC.

13. NCNG did not unreasonably favor CP&L with respect to its Wayne County combustion turbines.

14. At the time of the hearing, NCNG did not propose to change its rates.

15. As of the date of the hearing, NCNG had a temporary rate increment of $0.3644 per dekatherm (dt) for the Deferred Gas Costs - Sales Customers Only, effective November 1, 2000, and temporary rate decrements for Deferred Gas Costs—All Customers ranging from $(.0115)/dt for industrial boiler fuel customers to $(0.0490)/dt for residential-heating only customers, also effective November 1, 2000. NCNG proposed that these rate increments and decrements be a part of the Company's rates for twelve months ending October 31, 2001.

16. It is just and reasonable to continue the current level of temporary increments and decrements in NCNG's rates until further order of the Commission.

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

The evidence for these findings of fact is contained in the official files and records of the Commission. These findings are essentially informational, procedural or jurisdictional in nature and are facts uncontradicted by any of the parties.

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

The evidence for these findings of fact is contained in the testimony of NCNG witnesses Murphy and Hering, and the findings are based on G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

G.S. 62-133.4 requires that NCNG submit to the Commission information and data for an historical twelve-month review period, which information and data include NCNG'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 there be filed weather-normalized sales volume data, work papers, and direct testimony and exhibits supporting the information filed.

Witness Hering testified that Commission Rule R1-17(k)(6) required NCNG to submit to the Commission on or before February 1, 2001, the required information based on a twelve-month review period ended October 31, 2000. Witness Hering testified that NCNG complied with the filing requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), and an examination of witness Murphy's and Hering's testimony and exhibits confirms witness Hering's testimony. Witness Hering also testified that NCNG filed with the Commission and submitted to the Public Staff throughout the review period monthly accounting of the computations required by Commission Rule R1-17(k)(5)(c). Public Staff witness Perry confirmed that the Public Staff had reviewed the filings and that after NCNG made agreed upon corrections the filings would comply with the rules.

The Commission concludes that NCNG 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 October 31, 2000.

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

The evidence supporting these findings of fact is found in the testimony of NCNG witnesses Hering and Murphy and Public Staff witnesses Perry and Larsen.

NCNG witness Hering testified that as of October 31, 2000, NCNG had a debit balance of $15,474,360 in its deferred accounts. This debit balance consists of a debit balance of $11,299,513 in the Commodity Deferred Account - Sales Customers Only and a debit balance of $4,174,847 in the Demand Deferred Account - All Customers.

According to witness Murphy, during the period from November 1999 through October 2000, NCNG received net recoupment of fixed costs amounting to $358,981 as a result of capacity release and buy/sell agreements. The Company credited 75% of the net compensation from these transactions to its all customers deferred account pursuant to the Commission's Order in Docket No. G-100, Sub 67.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Perry and Larsen and Company witness Hering and is uncontroverted.

Witness Perry testified that the Public Staff had examined NCNG's accounting for gas costs during the review period and determined that NCNG, with one exception that NCNG has agreed to rectify, had properly accounted for its gas costs.

Based upon the testimony and exhibits of the witnesses, the monthly filings by NCNG as required by Commission Rule R1-17(k)(5)(c) and the finding of fact set forth above, the Commission concludes that NCNG has properly accounted for gas costs during the period of review.

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

The evidence supporting these findings of fact is found in the testimony of NCNG witnesses Davis, Murphy and Hering and Public Staff witness Larsen.

Witness Davis testified that the primary objective of NCNG's Board of Directors' gas supply acquisition policy is to ensure that the Company has adequate volumes of competitively priced natural gas to meet the peak day demands of all firm customers on its system and to provide the maximum service possible to all customers during the other times throughout the year. Witness Davis described the policy as a "best cost" policy. The key features of the policy include the requirement of a "portfolio mix" of long-term supply contracts, that the backup of peak gas supplies is maintained (mainly in the form of gas in storage), and that firm gas supplies be acquired primarily to meet peak-season firm requirements.

NCNG sells or transports gas to two groups, which are its firm and interruptible markets. Its firm market is principally residential, commercial and small industrial. NCNG's firm market also includes customers that have firm contracts for the purchase or transportation of certain volumes of gas and demand charges in their rates, including NCNG's four municipal customers.

Witness Murphy testified that NCNG has nine long-term supply contracts, including the Transco FS sales service contract, representing a total firm supply of 215,511 dts per day for winter delivery and lesser amounts in the remainder of the year. Witness Murphy also testified that of these nine contracts, two are winter-only contracts, which are utilized only during the five winter months. Witness Murphy further stated that two of the remaining contracts provide higher quantities in the winter months than the summer months, and the remaining five contracts have a level contract quantity year-round.

Witness Murphy testified that NCNG continued to have 5,199 dekatherms per day of Rate Schedule FSS (firm storage service) and related transportation from Columbia Gas Transmission, 2,070 dekatherms per day of GSS storage service from Transco, and 5,320 dekatherms per day of Transco's five-day LGA peaking service, as well as NCNG's on-system Barragan LNG peaking facility which can provide in excess of 100,000 dekatherms on a peak day.

Public Staff witness Larsen stated that, in addition to reviewing responses to the data requests posed to NCNG, the Public Staff reviewed gas purchase and transportation contracts, reservation or fixed cost fees, design day estimates, forecasted load duration curves, forecasted gas supply needs, customer load profile changes, and projections of capacity additions and supply changes. Based upon the Public Staff's examination, witness Larsen testified that in the Public Staff's opinion, NCNG's purchasing practices were reasonable and prudent.

In its post-hearing Brief filed on May 21, 2001, CUCA asserts that NCNG was imprudent because gas costs increased under the market-based contracts with gas suppliers, yet NCNG failed to engage in hedging transactions to lock in lower gas supply costs under fixed price contractual provisions. According to CUCA, the associated cost differential between a reasonable fixed price of gas and the market price of gas should be refunded.

NCNG responds in its Reply Brief that the advisability of hedging has been an issue for natural gas utilities regulated by the Commission for a number of years, but that the Commission has never suggested that the natural gas utilities should engage in hedging. In the Commission's recent informal investigatory proceeding on the advisability of hedging, nearly all of the information presented indicated that hedging does not save ratepayers gas cost expense. Hedging reduces volatility in gas costs, but, over the long term, gas costs are not reduced and may increase. If the Commission desires LDCs like NCNG to engage in hedging, generic rules should be implemented establishing procedures to be followed to ensure fair treatment to all involved parties.

NCNG further responds that, contrary to CUCA's argument, the fact that gas supply prices increased substantially and NCNG did not hedge is no evidence of imprudence. No evidence exists that NCNG failed appropriately to anticipate that gas prices would rise as high and as quickly as they did. Likewise, no evidence was presented quantifying the costs NCNG would or should have incurred to engage in hedging transactions. CUCA argues simply that gas supply costs would have been lower during the review period if NCNG had hedged. By the same token, there have been many other review periods where gas supply costs have fallen and in which gas costs recovered through rates would have been higher if NCNG had hedged. No justification exists for penalizing an LDC for not hedging just because gas costs increased during a single review period.

The Commission concludes that the gas costs incurred by NCNG during the review period ended October 31, 2000, were reasonable and prudently incurred, and NCNG should be permitted to recover 100 percent of its prudently incurred gas costs. The Commission cannot conclude that NCNG was imprudent not to hedge and cannot quantify the possible savings if it had hedged. The Commission has recently initiated an investigation to consider issues relating to hedging of natural gas by the LDCs.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence supporting this finding of fact is found in the testimony of NCNG witnesses Davis and Hering.

NCNG purchases liquefied natural gas storage capacity from Pine Needle LNG Company LLC, an interstate storage facility in which NCNG, through an affiliate, has an equity interest. NCNG received service from Pine Needle pursuant to FERC-approved rates during the test period and seeks to recover the cost thereof in this proceeding. A Pine Needle rate filing before the FERC increased Pine Needle's rate by about 7.5% during the test year. CUCA contends that NCNG is responsible to ensure that its Pine Needle costs are as low as possible and that NCNG failed to vigorously protect the interests of their ratepayers in FERC proceedings. CUCA would preclude NCNG from recovering the amount associated with the Pine Needle increase.

NCNG responds that CUCA has failed to show any imprudence on NCNG's part with respect to the Pine Needle proposed rate increase. The NCNG witnesses questioned on the issue of whether NCNG has intervened in the FERC docket merely testified that they were not sure whether NCNG had intervened or not.

The Commission strongly agrees that NCNG should act to ensure that the rates of FERC-regulated interstate suppliers--including affiliates--are just and reasonable. However, the record in this docket does not support CUCA's contention that NCNG failed to protect ratepayer interests. Witness Davis testified, ". . . I was privy to a couple of conversations with the Pine Needle operating group as to the type of increases and the reasoning behind them. Because it was primarily these electric charges that were different from what was anticipated by the operator when the project was started up and the fact that they would be trued up at a later date if indeed it didn't occur, we went along with those charges." On redirect, he added, "Basically, the increase in cost were due to the increases of electrical costs that were incurred over and above what was anticipated by Pine Needle and we had many discussions with the Pine Needle general operator about those. Those were subsequently trued up and there was an increase. I think a week or so ago there was a filing to decrease the rate from Pine Needle because the electric cost had actually subsided." The record shows that NCNG did not allow its interstate affiliate to pass through costs without scrutiny. NCNG was aware of the reasons for the increase and concurred with them. A failure to intervene in a FERC proceeding would not necessarily show imprudency.

This Commission continues to be concerned with the potential conflicts of interest that arise with the Pine Needle project and has repeatedly expressed that concern in dockets involving NCNG as well as the other North Carolina local distribution companies. In NCNG's last annual gas cost review (Docket No. G-21, Sub 393), the Commission expressed concern over whether NCNG's status as both an owner of Pine Needle (through an affiliate) and also as a business partner with Transco in Pine Needle would interfere with NCNG's responsibility to protect the ratepayers' interests in proceedings before the FERC. The order in that docket stated that the Commission was going to use NCNG's annual gas cost prudency reviews, as well as other proceedings, to scrutinize the Company's behavior in Pine Needle and Transco proceedings before the FERC. Yet, in this docket, neither of NCNG's witnesses were able to testify as to whether or not NCNG intervened in the FERC Pine Needle proceeding discussed above. NCNG witness Davis was able to articulate the issues in that docket and explain NCNG's position in that proceeding. No party refuted his testimony. However, with an explicit warning in an order issued less than a month prior to the date of the hearing in this docket that this Commission was going to be asking questions about NCNG's activities before the FERC, NCNG chose to put on two witnesses who couldn't testify as to whether or not NCNG had intervened in that major Pine Needle docket. The Commission concludes that, in its next annual gas cost review, NCNG should file a detailed explanation of what actions it has taken to ensure that the costs passed through to ratepayers from its Pine Needle affiliate and from its business partner, Transco, are just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the testimony of NCNG witnesses Murphy and Hering.

CUCA argues in its post-hearing Brief that in the absence of a transportation service agreement, NCNG is prohibited from varying from the terms of its tariff and the general rules and regulations included therewith. CUCA contends that cross-examination of NCNG's witnesses during the evidentiary hearing in this docket nevertheless disclosed that NCNG allowed CP&L to enjoy unlawful preferential treatment with respect to its Wayne County combustion turbines. For example, CP&L was not required to pay the same full margin rates that all other general transportation customers categories must pay and CP&L was not required to pay imbalance charges for some excess deliveries and may have received a credit against transportation rates. According to CUCA, NCNG should be required to recompute the amounts owned by CP&L during the test period as if CP&L was a transportation customer without an individualized contract during the test period, without receiving the benefit of waivers during the test period, and without receiving any other form of preferential treatment. NCNG should be ordered to credit all ratepayers the difference between the amount paid by CP&L and the amount that should have been paid by CP&L.

NCNG responds that no evidence exists in the record that the rates CP&L pays NCNG under the CP&L/NCNG Wayne County combustion turbine contract are unreasonable or imprudent in any respect. No evidence exists as to how the rate was computed or how the rate compares with NCNG's costs to serve CP&L. NCNG responds that NCNG has a number of contracts with large industrial customers that contain negotiated terms under which the rates are lower than the rate that a generic tariff might contain. These negotiated rates are necessary to prevent bypass and loss of the potential customer through conversion to nonnatural gas fuels. No record evidence exists that the NCNG/CP&L rate is unreasonable.

Likewise, NCNG states that there is no record evidence that the imbalance provisions in the NCNG/CP&L contract are unreasonable or imprudent. The provisions are designed to protect NCNG's customers when CP&L creates an imbalance and the price of gas changes before the imbalance can be rectified. In other situations, CP&L is given a credit to avoid unfairness at CP&L's expense. Under the contract the credit is an offset to transportation costs. Other NCNG customers have contracts with comparable provisions. The NCNG/CP&L contract has a limit on the imbalance that CP&L can have at the end of the month that limits the impact of the credit.

According to NCNG, during the initial period of operation for the Wayne County turbines, before the units actually went on line, the parties encountered difficulty matching gas deliveries to the times CP&L was testing the units. If CP&L could not use the gas it had purchased to conduct the test, NCNG used this gas to supplement its supply. At the end of the testing period, NCNG acquired all of it. NCNG applied the contractual imbalance provisions in the contract thereafter. No harm resulted to NCNG's customers. No evidence exists that CP&L has received an unreasonable preference or that any imbalances have resulted in increased costs to any of NCNG's other customers.

In the Order in NCNG's last prudence case dated March 19, 2001, the Commission recognized the practice of NCNG and other LDCs to negotiate rates with industrial customers to retain them on the system and avoid bypass. The Commission noted that there has not been a clearly defined, consistent procedure for handling such negotiations. Accordingly, the March 19, 2001 Order required contracts of more than one month but less than one year be filed within 30 days of execution. Negotiated contracts of more than one year shall be filed and require prior Commission approval. However, that order was not issued until after the test period in this case. Adherence to these procedures should prevent issues such as this one from arising in the future.

It appears from the testimony that CP&L and NCNG were in fact operating under the terms of the Transportation Service Agreement during the test year, even though it was not until after the test year, on November 9, 2000, in Docket No. G-21, Sub 406, that NCNG submitted the subject Agreement to the Commission and the Commission authorized NCNG to provide natural gas service to CP&L at its facilities in Wayne County pursuant to the contract by Order dated January 19, 2001. Accordingly, the Commission concludes that NCNG did not unreasonably favor the Wayne County combustion turbines.

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

Witness Hering testified that as of the date of the hearing NCNG had in rates a temporary rate increment of $0.3644 per dt for the Deferred Gas Costs - Sales Customers Only effective November 1, 2000, and temporary rate decrements for Deferred Gas Costs-All Customers ranging from S(.0115) per dt for industrial customers to S(0.0490) per dt for residential - heating only customers also effective November 1, 2000. These temporaries were proposed to be in the Company's rates for the twelve months ending October 31, 2001.

Public Staff witness Larsen testified that he agreed with the Company's proposal not to change its rates at this time.

The Commission believes that it is just and reasonable to continue the increment and decrements in NCNG's rates until further Order by the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That NCNG's accounting for gas costs and recoveries during the twelve-month period of review ended October 31, 2000, is approved;

2. That NCNG is authorized to recover 100 percent of its gas costs incurred during the twelve-month period of review ended October 31, 2000, as the same were reasonable and prudently incurred; and

3. That the increments and decrements in NCNG's rates, which are presently in place, remain unchanged until further Order of the Commission.

ISSUED BY ORDER OF THIS COMMISSION.
This the 25th day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

dh072401.01

DOCKET NO G-40, SUB 15

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION:

In the Matter of		
Application of Frontier Energy, L.L.C. for	)	
Annual Review of Gas Costs Pursuant to	)	ORDER ON ANNUAL REVIEW
G.S. 62-133.4(c) and Commission Rule R1-17(k)(6)	)	OF GAS COSTS
	)	

HEARD ON: Tuesday, March 6, 2001, at 10:00 a.m., in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27602

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners J. Richard Conder and Lorinzo L. Joyner

APPEARANCES:

FOR FRONTIER ENERGY, L.L.C.:

M. Gray Styers, Jr., Kilpatrick Stockton, L.L.P, 3737 Glenwood Avenue, Suite 400, Raleigh, North Carolina 27612

FOR THE USING AND CONSUMING PUBLIC:

Vickie Moir and Gina Holt, Staff Attorneys, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326.

BY THE COMMISSION: G.S. 62-133.4 authorizes gas cost adjustment proceedings for natural gas local distribution companies. G.S. 62-133.4(c) provides that the North Carolina Utilities Commission ("Commission") shall conduct annual review proceedings to compare each natural gas utility's prudently-incurred costs with costs recovered from all of the utility's customers served during the test period. Commission Rule R1-17(k)(6) prescribes the procedures for such annual reviews of natural gas costs.

On December 1, 2000, Frontier Energy, L.L.C. ("Frontier" or "Company") filed the testimony and exhibits of William Purcell, Vice President and General Manager of Frontier, and Rodger R. Schwecke, General Manager of Bangor Gas and formerly responsible for customer assessment and market development of Frontier's services, regarding Frontier's gas costs as reviewed pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

On December 7, 2000, the Commission issued an order scheduling a hearing to conduct an annual review of the cost of gas supply, storage and transportation for Frontier, setting other procedural deadlines, issuing discovery deadline guidelines, and requiring public notice of the hearing. The Commission noted that this is the first gas cost review proceeding for Frontier since it began operations; therefore, this review covers the period from start-up through September 30, 2000.

On February 27, 2001, the Public Staff filed the joint direct testimony of witnesses James G. Hoard, Assistant Director, Accounting Division, and Jeffrey L. Davis, Utilities Engineer, Natural Gas Division. On March 1, 2001, Frontier filed an Affidavit of Publication indicating that customer notice had been provided in accordance with the Commission's procedural order. No other parties intervened, and Frontier witnesses and Public Staff witnesses were the only witnesses to present testimony in this proceeding.

Any other motions, filings, and orders not specifically mentioned above are a matter of public record. Based on the information contained in the filings, the testimony and exhibits introduced at the hearing, and the entire record of this proceeding, the Commission now 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 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). Frontier's public utility operations are subject to the jurisdiction of this Commission.

2. Frontier is an LDC primarily engaged in the purchase, transportation, distribution, and sale of natural gas to approximately 100 current customers in the State of North Carolina (fifty-two as of September 30, 2000). Approximately 99 percent of Frontier's market is comprised of deliveries to industrial or large commercial customers, which either purchase gas from Frontier or transport gas on Frontier's system. The majority of these customers have the capability to use a fuel other than natural gas (e.g., distillate fuel oil, residual fuel oil, or propane) and will use an alternate fuel when it is priced less than natural gas. The remainder of Frontier's sales are primarily to residential and small commercial customers. Frontier's primary competition for these smaller market segments is electricity.

3. In compliance with G.S. 62-133.4 and Commission Rule R1-17(k)(6), Frontier filed with the Commission and submitted to the Public Staff actual gas costs and volumes of purchased gas based on a review period beginning in October 1998 and ending September 30, 2000.

4. The contracts that Frontier entered into with its suppliers were prudent in light of the circumstances that existed when the contracts were entered, and the costs associated with the contracts during the review period were prudently incurred.

5. The appropriate deferred account balance for Frontier as of September 30, 2000, was \$513,242, composed of (1) the gas cost true-up of \$119,446, (2) negotiated losses of \$360,956 and (3) accrued interest of \$32,840.

6. On a prospective basis, the gas cost true-up should include all prudently incurred gas costs and Frontier should not record negotiated losses in the deferred account. Accordingly, Frontier's tariffs should be amended to reflect this true-up mechanism.

7. It is not appropriate at this time to implement an increment in the Company's rates to collect prudently incurred amounts in the deferred account.

8. Frontier is authorized to provide gas service to industrial customers pursuant to the special contracts it has filed in this docket.

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

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 the testimony, schedules and exhibits filed by the witnesses for Frontier and the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding is found in the testimony and exhibits of Frontier witness Purcell, the testimony of Public Staff witnesses Davis and Hoard, and the provisions of G.S. 62-133.4(c) and Commission Rule R1-17(k)(6).

The relevant statute, G.S. 62-133.4(c), requires Frontier to submit to the Commission specified information and data for a historical 12-month test 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 weather-normalized sales volume data, work papers, and direct testimony and exhibits supporting the information filed. Because this proceeding is the first annual review since Frontier began its operations, this review covers a 24-month review period beginning with Frontier's initial gas purchases in October 1998 through September 30, 2000.

An examination of witness Purcell'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). Witness Purcell testified that Frontier filed with the Commission prior to the hearing, and provided to the Public Staff, its updated monthly accounting of the computations required by Commission Rule R1-17(k)(5)(c). Attached to Mr. Purcell'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.

The Commission concludes that, based on the testimony and exhibits and the agreement between the Public Staff and Frontier, for the purposes of this proceeding Frontier has complied with all of the procedural requirements of G.S. 62-133.4(c) and Commission Rule R1-17(k) for the review period ending September 30, 2000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding is found in the testimony and exhibits of Frontier witnesses Schwecke and Purcell and Public Staff witnesses Hoard and Davis.

Frontier's witness Purcell testified that Frontier's gas supply policy is best described as a "best cost" supply strategy. This gas supply strategy is based upon several criteria: flexibility, security of supply, and the cost of the gas. The foremost criteria for Frontier are flexibility and security of supply.

This flexibility is required because of the daily changes in Frontier's market requirements related to the unpredictable nature of weather, the rapid growth of customers during the test period, and the ability of Frontier's industrial customers to switch to alternate fuels and/or purchase their own gas. While each of Frontier's gas supply agreements has different purchase commitments and swing capabilities (e.g., ability to adjust purchase volumes within the contract volume), the gas supply portfolio as a whole must be capable of handling the monthly, daily, and hourly changes in Frontier's market requirements. Frontier understands the necessity of having security of supply to provide reliable, dependable natural gas service and has demonstrated its ability to do so. The supply strategy and the contracts implementing this strategy have allowed Frontier to accomplish this objective.

Frontier's first natural gas supplier (Supplier 1) was an affiliated company of Frontier Energy. The purchasing agreement with Supplier 1 was filed and approved by Commission Order dated June 3, 1999, in Docket No. G-40, Sub 1. At that time, Frontier's primary needs were security of supply and maximum flexibility, because of the great uncertainty in Frontier's load and growth. In late 1998, Frontier had one industrial customer. By July 1999, five industrial customers were receiving gas. Total system demand was increasing arithmetically with the addition of each customer. These circumstances were magnified when, during these first few months of operations, Frontier began experiencing huge, unexplained fluctuations in Frontier's daily requirements from Transco – from near zero to far in excess of Frontier's daily nominations -- as the result of pressure changes on the Transco pipeline caused by the operation of a compressor station just downstream from Frontier's tap. These fluctuations were eliminated by the installment of a pressure regulating value.

In August 2000, Frontier switched to a second supplier (Supplier 2), chosen after competitive bidding by several suppliers, because Supplier 2 offered an economically attractive and transparent pricing structure. Frontier owns no interstate capacity but currently acquires all of its gas from Supplier 2, a wholesale gas supplier with interstate capacity. Several years in the future when Frontier's load growth levels out, Frontier witness Purcell testified that it will evaluate the economics of acquiring its own interstate capacity.

Public Staff witnesses Hoard and Davis testified that because Frontier is still essentially a start-up company with substantial construction activity, its gas procurement practices necessarily differ from those of the four mature North Carolina LDCs. As Frontier's system has developed, the first customers to attach to its system have been industrial customers, with relatively few residential customers thus far. The majority of those industrial customers were offered initial conversion rates to switch from alternative fuels and utilize natural gas, offered negotiated rates to remain on gas service, and are designated to be interruptible should the system requirements justify it. Most of them also have alternative fuel sources and can switch on or off the system each month.

Given this type of customer profile, firm long-term capacity contracts similar to those used by the mature LDCs were not only unnecessary, but would have been expensive given the fact that firm capacity demand costs would have to be paid whether or not the interruptible load was on for a given month, or if the load was lost to alternative fuels because of price sensitivity. Moreover, system demand is rapidly rising as more customers are added to the system. In this environment, flexibility of supply to adapt to changing conditions and rapid growth is essential. Therefore, in this case, the Public Staff Panel testified that the normal standard that the Public Staff uses for gas cost evaluations for the mature LDCs is not practical or relevant for Frontier given its current state of construction, customer profiles, and peak day requirements. The types of contracts that Frontier has entered into with its suppliers have allowed flexibility while providing dependable service to meet Frontier's customers' requirements. The Public Staff Panel testified that based on its investigation and review of data in this filing, the Public Staff believes the Company's gas costs were prudently incurred.

Based on the testimony described above, the Commission concludes Frontier's gas costs were prudently incurred. The gas supply contracts that Frontier has arranged had the flexibility to meet its market requirements in a secure and cost-effective manner.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence for these findings can be found in the testimony and exhibits of Public Staff witnesses Hoard and Davis and Frontier witnesses Purcell and Schwecke. The Public Staff Panel Exhibit I indicates that, as of September 30, 2000, Frontier had a deferred account balance of $513,242, composed of the gas cost true-up of $119,446, negotiated losses of $360,956, and accrued interest of $32,840. The parties were in agreement regarding the appropriateness of the deferred account amounts. The Commission therefore concludes that Frontier's deferred account balance as of September 30, 2000 is $513,242.

Frontier's original accounting had included an additional $360,956 of gas supply costs in its gas cost true-up balance; however, the Public Staff panel testified that they did not believe that Frontier had strictly complied with the definitions in Rule R1-17(k) because Frontier included all of its gas costs in its deferred account and did not distinguish between the different components of these costs. As indicated in witness Purcell's rebuttal testimony, Frontier agreed with the Public Staff regarding how the costs should be treated for purposes of this proceeding. Namely, the parties agreed that Frontier should remove $360,956 of gas costs from the commodity true-up and should be allowed to record $360,956 of negotiated losses. In support of this agreement, the Public Staff stated that, otherwise, Frontier would be entitled to recover more negotiated losses than $360,956.

There is no dispute that, in light of Frontier's unique circumstances, Frontier's gas purchases have been prudent and the costs have been prudently incurred. The Public Staff Panel testified that natural gas could not be delivered to Frontier's sales customers without Frontier incurring the capacity and other necessary costs. Unless these costs are passed along to Frontier's sales customers, Frontier would be required under its current tariffs to assume the risks of those costs for industrial customers who could then avoid them by leaving the system to use alternative fuels. The Commission believes the procedure agreed to by the Public Staff and Frontier balances Frontier's right to recover prudently incurred costs without overly burdening Frontier's small but growing number of customers.

The Public Staff Panel testified that at this stage of the Frontier's development, most of Frontier's load is composed of industrial customers who possess the ability to transport natural gas or purchase alternative fuels. With the Company's throughput growing dramatically from one month to the next, the Company is still very much in a start-up phase. The Public Staff Panel testified that some changes should be made to Frontier's deferred account procedures and tariffs on a prospective basis to better reflect Frontier's current business situation. The Public Staff and the Company agreed that, on a prospective basis, the gas cost true-up should include all prudently incurred gas costs, including capacity, interstate transportation, and other necessary costs, and that the Company will no longer be permitted to record negotiated losses in the deferred account.[1] Permitting a true-up of all prudently incurred gas costs should provide management flexibility to better meet customer needs and manage system supply. On the other hand, terminating Frontier's ability to recover negotiated losses should protect against the Company accumulating a potentially large regulatory asset that could be recoverable from future ratepayers. In addition, Frontier witness Purcell testified that adoption of the agreement between Frontier and the Public Staff, and the tariff changes that are a part of that agreement, would be consistent with Frontier's customer expectations.

The Commission concludes that, based on the evidence presented in this proceeding, on a prospective basis, the gas cost true-up should include all prudently incurred bundled costs of natural gas delivered to Frontier's city-gate, and Frontier should not record negotiated losses in its deferred account. Accordingly, Frontier's tariffs should be amended consistent with the attached Appendix A.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding is found in the testimony and exhibits of Public Staff witnesses Davis and Hoard.

Public Staff witnesses Davis and Hoard testified that the Public Staff believes that Frontier's volume level is presently at a stage that an increment placed in rates to collect the current deferred

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[1] The Commission's general gas cost procedures, definitions and rules as set forth in Rule R1-17(k) should become applicable to Frontier effective with its first general rate case order.

account balance may be counter-productive in attracting and keeping new customers. The Public Staff witnesses also stated that they expected Frontier's customer and volume level to grow significantly in the near term. Public Staff witnesses Davis and Hoard recommended that through careful monitoring of the deferred account activity, the balance can be reduced through normal operations and/or the implementation of an increment at a later date in conjunction with a future Purchased Gas Adjustment filing as conditions warrant. The Company did not object to the Public Staff's recommendation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is found in the testimony and exhibits of Public Staff witnesses Davis and Hoard and the special contracts Frontier filed in this docket.

Frontier has filed thirteen special contracts with large industrial customers in its service territory: Tyson Foods, Roaring River Feed Mill, dated August 3, 1998; Tyson Foods, Wilkesboro Plant, dated August 3, 1998; Cross Creek Apparel, dated January 5, 2000; CertainTeed Corporation, dated November 10, 1999; Sara Lee Hosiery, dated May 5, 1999; Candle Corporation of America, dated February 11, 1999; Kentucky Derby Hosiery, dated August 25, 2000; Sara Lee Sock Company, dated November 9, 1999; Pine State Knitwear, dated April 14, 2000; Tyson Foods, Hays-Wilkesboro Hatchery 3, dated August 3, 1998; North Carolina Foam Industries, dated August 24, 2000; Carl Rose & Sons, Inc., dated January 17, 2000; and Renfro Corporation, dated May 22, 2000. The Public Staff has reviewed these contracts in view of G.S. 62-140 and recommended that the Commission authorize Frontier to provide gas service pursuant to the contracts. No party objected to this recommendation.

Therefore, the Commission concludes that these special contracts do not violate G.S. 62-140 and authorizes Frontier to provide gas service consistent with their terms.

IT IS, THEREFORE, ORDERED as follows:

1. That Frontier's accounting for gas costs and recoveries during the review period ending September 30, 2000, as adjusted pursuant to the recommendations of the Public Staff, is approved, resulting in a deferred account balance of $513,242 as of September 30, 2000;

2. That the gas costs incurred by Frontier during the review period ending September 30, 2000, were reasonable and prudently incurred;

3. That Frontier no longer recover negotiated losses;

4. That Frontier amend its tariffs consistent with attached Appendix A; and

5. That Frontier is authorized to provide gas service pursuant to the special contracts filed in this docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of April, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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Appendix A

PROCEDURE FOR RATE ADJUSTMENTS UNDER G.S. 62-133.4

1. PURPOSE. The purpose of this Appendix is to set forth the procedures by which Frontier Energy, L.L.C. can file to adjust its rates pursuant to G.S. 62-133.4. The intent of these procedures is to permit Frontier to recover 100% of its prudently incurred gas costs applicable to its North Carolina operations.

2. DEFINITIONS. As used in this Appendix, the following definitions shall apply:

"LDC" shall mean Frontier Energy LLC.

"Gas Costs" shall mean the total delivered cost of gas paid or to be paid to Suppliers, including but not limited to all commodity/gas charges, demand charges, peaking charges, surcharges, emergency gas purchases, overrun charges, capacity charges, standby charges, reservation fees, gas inventory charges, minimum bill charges, minimum take charges, take-or-pay charges, take-and-pay charges, storage charges, service fees and transportation charges, and any other similar charges in connection with the purchase, storage or transportation of gas for the LDC's system supply.

"Suppliers" shall mean any person or entity, including affiliates of the LDC, who locates, produces, purchases, sells, stores and/or transports natural gas or its equivalent for or on behalf of the LDC. Suppliers may include, but not be limited to, interstate pipeline transmission companies, producers, brokers, marketers, associations, intrastate pipeline transmission companies, joint ventures, providers of Liquefied Natural Gas, Liquefied Petroleum Gas, Synthetic Natural Gas and other hydrocarbons used as feed stock, other local gas distribution companies and end-users.

"Benchmark Gas Costs" shall mean the LDC's estimate of the City Gate Delivered Gas Costs for long-term gas supplies. The Benchmark Gas Costs may be amended from time to time as provided in Section (3)(a).

"City Gate Delivered Gas Costs" shall mean the total delivered Gas Costs to the LDC at its city gate.

3. RATE ADJUSTMENTS UNDER THESE PROCEDURES.

(a) **Sales Rates.** In the event the LDC anticipates a change in its City Gate Delivered Gas Costs, the LDC may apply and file revised tariffs, effective on 14 days notice, in order to increase or decrease its rates to its customers as hereinafter provided. The Commission may issue an order allowing the rate change to become effective simultaneously with the effective date of the change or at any other time ordered by the Commission. If the Commission has not issued an order within 120 days after the application, the LDC may place the requested rate adjustment into effect. Any rate adjustment under this Section (3)(a) is subject to review under Section (6).

(b) **Transportation Rate.** Firm and/or interruptible transportation rates shall be computed on a per unit basis by subtracting the per unit Benchmark Gas Cost included in the applicable firm or interruptible sales rate schedule from the applicable firm or interruptible rate schedule exclusive of any decrements or increments. Deferred account increments or decrements shall not apply to transportation rates unless the Commission specifically directs otherwise.

4. TRUE-UP OF GAS COSTS.

(a) **Gas Costs.** On a monthly basis, the LDC shall determine with respect to gas sold (including company use and unaccounted for) during the month the per unit difference between (a) the Benchmark Gas Cost most recently approved and (b) the actual Gas Costs incurred. The product of the actual volumes multiplied by the per unit difference shall be recorded in the LDC's deferred account. Increments and decrements for Gas Costs flow to all sales rate schedules.

(b) **Supplier Refunds and Direct Bills.** In the event the LDC receives supplier refunds or direct bills with respect to gas previously purchased, the amount of such supplier refunds or direct bills will be recorded in the appropriate deferred account, unless directed otherwise by the Commission.

5. OTHER

(a) Gas Costs changes not tracked concurrently shall be recorded in the LDC's appropriate deferred account.

(b) The Gas Cost portion of gas inventories shall be recorded at actual cost and the difference in that cost and the cost last approved under Section (3)(a) shall be recorded in the deferred account when the gas is withdrawn from inventory.

(c) The LDC shall file with the Commission (with a copy to the Public Staff) a complete monthly accounting of the computations under these procedures, including all supporting work papers, journal entries, etc., within 45 days after the end of each monthly reporting period. All such computations shall be deemed to be in compliance with these procedures unless within 60 days of such filing the Commission or the Public Staff notifies the LDC that the computations may not be in compliance; provided, however, that if the Commission or the Public Staff requests additional information reasonably required to evaluate such filing, the running of the 60 day period will be suspended for the number of days taken by the LDC to provide the additional information.

(d) Periodically, the LDC may file to adjust its rates to refund or collect balances in the deferred account through decrements or increments to current rates. In filing for an increment or decrement, the LDC shall state the amount in the deferred account, the time period during which the increment or decrement is expected to be in effect, the rate classes to which the increment or decrement is to apply, and the level of volumes estimated to be delivered to those classes.

6. ANNUAL REVIEW.

(a) Annual Test Periods and Filing Dates. The LDC will submit to the Commission the information and data required in Section (6)(c) for a historical 12-month test period. This information will be filed on or before December 1 of each year based on a test period ended September 30.

(b) Public Hearings. The Commission will schedule an annual public hearing pursuant to G.S. 62-133.4(c) in order to compare the LDC's prudently incurred Gas Costs with Gas Costs recovered from all its customers that it served during the test period. The public hearing will be on the first Tuesday of March. The Commission, on its own motion or the motion of any interested party, may change the date for the public hearing and/or consolidate the hearing required by this section with any other docket(s) pending before the Commission with respect to the affected LDC.

(c) Information Required In Annual Filings. The LDC will file information and data showing the LDC's actual gas costs, volumes of purchased gas, weather-normalized sales volumes, sales volumes, negotiated sales volumes and transportation volumes and such other information as may be directed by the Commission. All such information and data will be accompanied by work papers and direct testimony and exhibits of witnesses supporting the information.

(d) Notice of Hearings. The LDC will publish a notice for two (2) successive weeks in a newspaper or newspapers having general circulation in its service area, normally beginning at least 30 days prior to the hearing, notifying the public of the hearing before the Commission pursuant to G.S. 62-133.4 and setting forth the time and place of the hearing.

(e) Petitions to Intervene. Persons having an interest in any hearing held under the provisions of this Procedure may file a petition to intervene setting forth such interest at least 15 days prior to the date of the hearing. Petitions to intervene filed less than 15 days prior to the date of the hearing may be allowed in the discretion of the Commission for good cause shown.

(f) Filing of Testimony and Exhibits by the Public Staff and Intervenors. The Public Staff and other intervenors may file direct testimony and exhibits of witnesses at least 15 days prior to the hearing date. If a petition to intervene is filed less than 15 days prior to the hearing date, it shall be accompanied by any direct testimony and exhibits of witnesses the intervenor intends to offer at the hearing.

(g) Filing of Rebuttal Testimony. The LDC may file rebuttal testimony and exhibits within 10 days of the actual receipt of the testimony of the party to whom the rebuttal testimony is addressed.

DOCKET NO. G-3, SUB 224

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of NUI Corporation for Approval of Exchange of Shares Between NUI Holding Company and NUI Corporation	)	ORDER GRANTING PETITION

HEARD: Thursday, November 2, 2000, at 9:30 a.m., in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner William R. Pittman, Presiding; Chairman Jo Anne Sanford, and Commissioner Judy Hunt

APPEARANCES:

For NUI Corporation, d/b/a NUI North Carolina Gas

James H. Jeffries IV, Amos, Jeffries & Robinson, L.L.P., Post Office Box 787, Greensboro, North Carolina 27402

For Carolina Utility Customers Association:

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

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

BY THE COMMISSION: On February 1, 2000, NUI Corporation, d/b/a NUI North Carolina Gas (NUI NC Gas or the Company), filed a Petition for approval to exchange shares between NUI Holding Company and NUI Corporation pursuant to G.S. 62-111(a) to effect a corporate restructuring and establish an exempt holding company structure under the Public Utility Holding Company Act of 1935 (PUHCA). In its Petition, NUI NC Gas also sought a determination by the Commission that NUI Holding Company's issuance of shares in conjunction with the proposed share exchange was not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

On February 23, 2000, Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene in this proceeding, which was subsequently granted by the Commission on March 6, 2000.

On September 19, 2000, the Commission issued its Order Scheduling Hearing, Establishing Procedural Deadlines, and Requiring Public Notice. This Order established a hearing date of Thursday, November 2, 2000, set prefiled testimony dates, and required NUI NC Gas to give notice to its customers of the hearing on this matter.

On September 27, 2000, the Company filed the direct testimony of A. Mark Abramovic. On October 30, 2000, CUCA filed the direct testimony of Kevin W. O'Donnell.

On November 1, 2000, the Company and the Public Staff filed a Stipulation in which they reached agreement and resolved all issues in the case as between the Company and the Public Staff. Also on November 1, 2000, the Company filed the rebuttal testimony of its witness Abramovic.

The matter came on for hearing as scheduled on November 2, 2000. No public witnesses appeared.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. NUI NC Gas is an operating division of NUI Corporation, which is a corporation organized under the laws of the state of New Jersey and duly registered to do business in North Carolina.

2. NUI NC Gas is engaged in the business of transporting, distributing, and selling natural gas in a franchised area which consists of all of Rockingham County and part of Stokes County in the northern piedmont region of North Carolina.

3. NUI NC Gas is a public utility as defined by G.S. 62-3(23), is subject to the jurisdiction of this Commission, and is lawfully before this Commission upon its Petition for approval of its corporate restructuring pursuant to G.S. 62-111(a).

4. NUI NC Gas' testimony, exhibits, affidavits of publication and published hearing notices are in compliance with the provisions of the North Carolina General Statutes and the Rules and Regulations of this Commission.

5. NUI Corporation seeks authority, pursuant to G.S. 62-111(a), to exchange its shares with NUI Holding Company for a like number of shares of NUI Holding Company to form an exempt holding company structure under PUHCA. The effect of this share exchange and holding company formation would be to transfer ultimate ownership of the regulated North Carolina public utility assets and operations of NUI NC Gas to the new holding company. NUI NC Gas also seeks a determination by the Commission that NUI Holding Company's issuance of shares in conjunction with the proposed share exchange is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

6. In order for NUI NC Gas to obtain Commission approval for its proposed share exchange, NUI NC Gas must demonstrate that the proposed share exchange is justified by the public convenience and necessity.

7. NUI NC Gas is a multi-state public utility with regulated natural gas distribution operations in the states of New Jersey, Maryland, Pennsylvania, New York, Florida and North Carolina. In addition to these regulated distribution operations, NUI NC Gas also operates a number of unregulated businesses on a multi-state basis including those engaged in energy brokering, sales outsourcing, business and environmental services.

8. Under NUI NC Gas' current corporate structure, its unregulated businesses are operated as subsidiaries of NUI Corporation – the certificated public utility providing local distribution services in North Carolina and other States.

9. NUI NC Gas' proposed restructuring will create a holding company structure through which NUI NC Gas' regulated operations will be segregated from its unregulated businesses.

10. Other than this segregation, no change in the identity of the North Carolina certificated public utility will occur as a result of NUI NC Gas' proposed share exchange.

11. No change in the rates, terms, or conditions of service pursuant to which North Carolina customers are served will occur as a result of NUI NC Gas' proposed share exchange.

12. The protective provisions agreed to by NUI NC Gas and the Public Staff in the Stipulation are sufficient to ensure that there will be no adverse impact on the rates and service of NUI NC Gas ratepayers as a result of the share exchange and will serve to protect North Carolina ratepayers, as much as possible, from any potential harm arising therefrom. These provisions are generally consistent with conditions imposed by the Commission in previous cases involving the establishment of exempt holding company structures under PUHCA, and are appropriate for use by the Commission in this docket.

13. The benefits demonstrated by NUI NC Gas outweigh the potential harms and risks associated with the proposed transactions.

14. The exchange of shares between NUI Holding Company and NUI Corporation, as proposed in NUI NC Gas' Petition in this proceeding, is justified by the public convenience and necessity.

15. The issuance of shares by NUI Holding Company, as proposed herein, is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

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

These findings of fact are jurisdictional and/or informational in nature and are not contested by any party. They are supported by the Petition, the testimony and exhibits of the various witnesses, the records of the Commission in other proceedings and the Affidavits of Publication filed with the Commission in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The nature of the authorization sought by NUI NC Gas in this docket is undisputed and is set forth in NUI NC Gas' Petition and the exhibits attached thereto as well as the testimony and exhibits of Company witness Abramovic.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The basis for this finding is found in G.S. 62-111(a) which provides that no "merger or combination affecting any public utility [shall] be made through acquisition or control by stock purchase or otherwise, except after application to and written approval by the Commission, which approval shall be given if justified by the public convenience and necessity." NUI NC Gas' Petition recites that it is brought pursuant to G.S. 62-111(a) and expressly seeks Commission approval of its proposed share exchange pursuant to that statute.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding is contained in NUI NC Gas' Petition and the testimony of Company witness Abramovic.

In its Petition, NUI NC Gas indicates that, in addition to its regulated provision of natural gas service in North Carolina, it is engaged in the "business of transporting, distributing and selling natural gas in the states of New Jersey (Elizabethtown Gas), Florida (City Gas Company), Pennsylvania (Valley Cities Gas), Maryland (Elkton Gas) and New York (Waverly Gas)." This assertion is confirmed by the direct prefiled testimony of Company witness Abramovic and is consistent with previous findings made by the Commission in other dockets involving NUI NC Gas.

In its Petition and in the prefiled direct testimony of Company witness Abramovic, NUI NC Gas also indicates that it either operates or owns a significant interest in a number of businesses which provide unregulated services on a multi-state or, in some cases, a nationwide basis. These businesses include energy brokering, sales outsourcing, business services and environmental services, among others.

The assertions contained in NUI NC Gas' Petition in this regard and affirmed in the prefiled direct testimony of Company witness Abramovic are undisputed and no other party presented evidence on these matters.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is undisputed and is contained in NUI NC Gas' Petition and the prepared direct and rebuttal testimony of Company witness Abramovic. In his direct prefiled testimony, Mr. Abramovic indicates that NUI NC Gas currently operates its unregulated businesses as indirect subsidiaries of NUI Corporation, the same company engaged in providing regulated public utility service in North Carolina, and elsewhere. This testimony is corroborated by NUI NC Gas' Rebuttal Exhibit AMA-1 attached to the prefiled rebuttal testimony of Company witness Abramovic which illustrates graphically and descriptively that NUI's unregulated businesses are currently operated through subsidiaries of NUI Corporation. No other party presented evidence on this matter.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding is undisputed and is contained in NUI NC Gas' Petition and the testimony and exhibits of Company witness Abramovic.

In its Petition, NUI NC Gas indicates that following its proposed share exchange and the establishment of a holding company structure, all of NUI's unregulated businesses will become direct subsidiaries of NUI Capital Corporation and indirect subsidiaries of NUI Holding Company instead of subsidiaries of NUI NC Gas. In his direct prefiled testimony, Mr. Abramovic indicates that following the proposed restructuring, all of NUI's regulated utility operations will remain under NUI Corporation but that all of NUI's unregulated businesses will be stripped off and consolidated under a sister company – NUI Capital Corporation. Mr. Abramovic further testified that both NUI NC Gas and NUI Capital Corporation will be direct subsidiaries of NUI Holding Company following the restructuring proposed herein. This post-exchange structure is also reflected in NUI Rebuttal Exhibit AMA-1 attached to the prefiled rebuttal testimony of Company witness Abramovic.

No other party filed testimony or presented other evidence regarding the structure of NUI after the share exchange.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding is undisputed and is contained in the Petition and the testimony and exhibits of Company witness Abramovic and the Stipulation entered into between the Company and the Public Staff.

In its verified Petition, NUI NC Gas indicates that "no change in the identity of the certificated Public Utility or the scope or nature of public utility service offered by NUI NC Gas will result from the exchange of shares discussed herein." This assertion is repeated in the prefiled direct testimony of Company witness Abramovic which provides that following the proposed restructuring "NUI Corporation will continue to be the certificated public utility providing service to customers in North Carolina." This fact is further verified by the current and post-restructuring organizational charts contained in NUI Rebuttal Exhibit AMA-1 (Proxy Statement) attached to the prefiled rebuttal testimony of Company witness Abramovic which clearly show that all regulated operations of NUI will remain consolidated under what is currently NUI Corporation (and which will be renamed NUI Utilities, Inc.) following the proposed share exchange.

In the Stipulation, the Company and the Public Staff stipulate that "there will be no change in the identity of the certificated entity providing public utility service in North Carolina" as a result of the proposed share exchange. No other party presented evidence on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding is undisputed and is contained in the Petition and the testimony and exhibits of Company witness Abramovic.

In its verified Petition, NUI NC Gas indicates that "the exchange of shares described herein will not . . . impact or result in any change to the level, quality, price or terms of service provided by NUI NC Gas to its North Carolina customers." This assertion is supported by the prefiled direct testimony of Company witness Abramovic which provides that "no change in any rates, terms or conditions of service will result from the reorganization."

This conclusion is also supported by the Stipulation entered into between the Public Staff and the Company wherein both agree that "there will be no change in . . . the rates terms or conditions [of] . . . service rendered" by NUI NC Gas as a result of the proposed restructuring.

The Commission also notes: (1) that NUI NC Gas' Petition seeks no changes to the rates, terms or conditions of its service to North Carolina customers in this docket; and (2) that the rates, terms and conditions upon which NUI NC Gas provides service are matters within the Commission's jurisdiction and cannot be changed or altered without Commission approval. No other party presented evidence on this issue.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 & 13

The evidence for these findings is contained in the Petition and in the testimony and exhibits of Company witness Abramovic and CUCA witness O'Donnell, and in the Stipulation between the Company and the Public Staff.

The Stipulation between the Company and the Public Staff recites certain stipulated facts with which the Public Staff agrees relative to NUI NC Gas' Petition in this proceeding. Among these are that "NUI NC Gas reasonably believes, based on opinions received from its [Securities and Exchange Commission (SEC)] counsel, that following its proposed restructuring, it will qualify for an exemption from the requirements of the Public Utility Holding Company Act of 1935." In the Stipulation, NUI NC Gas and the Public Staff also stipulate that any Commission order approving NUI NC Gas' proposed restructuring should contain three provisions designed to protect North Carolina ratepayers from any adverse consequences that might conceivably result from the proposed holding company structure. These provisions are:

(1) It is assumed, based on representations made by NUI NC Gas and NUI Corporation, that the transfer of 100 percent of NUI NC Gas' outstanding shares to NUI Holding Company, in exchange for a like number of shares of the stock of NUI Holding and the establishment of NUI Holding as NUI NC Gas' parent will not cause NUI Holding to become a registered holding company under the Public Utility Holding Company

Act of 1935 (PUHCA). If NUI Holding, or any of its affiliates, engage in acquisitions or other actions that could require it to become a registered holding company under PUHCA, NUI NC Gas will notify the Utilities Commission at least 30 days prior to filing with the SEC any application necessary to obtain authorization to take such actions or, where no such application is necessary, at least 60 days prior to taking such actions.

(2) NUI NC Gas and NUI Holding will bear the full risk of any preemptive effects of PUHCA. The previous sentence includes, but is not limited to, an agreement by NUI Holding and NUI NC Gas to take all such actions as the Commission finds are necessary and appropriate to hold North Carolina retail ratepayers harmless from rate increases, foregone opportunities for rate decreases or other effects of such preemption, including filing with and obtaining approval from the SEC for such commitments as the Commission deems necessary to prevent such preemptive effects.

(3) If the SEC concludes that NUI Holding became a registered holding company by virtue of the transfer approved herein, or if NUI Holding or any of its affiliates engage in acquisitions or other actions that could require it to become a registered holding company, NUI Holding is advised, and the Commission finds, that NUI Holding shall be presumptively subject to the PUHCA conditions imposed by the Commission in prior proceedings involving registered holding companies, subject to NUI Holding's right to file for a waiver or modification of such conditions upon good cause shown.

In his prefiled rebuttal testimony, Mr. Abramovic indicates that the Company has a high degree of confidence that it will qualify for an exemption from the requirements of PUHCA. Mr. Abramovic also testifies that even if this confidence turns out to be misplaced, the protective provisions agreed to in the Stipulation provide complete protection for North Carolina ratepayers from any potentially negative impacts from the proposed restructuring.

Mr. O'Donnell's testimony on this issue is that the potential for federal preemption associated with a finding by the SEC that NUI is a non-exempt holding company after the restructuring represents a "cost" to North Carolina ratepayers in the form of increased risk.

After carefully reviewing all of the evidence on this issue, the Commission concludes that there is some risk to North Carolina ratepayers associated with the possible preemption of this Commission's authority should the SEC find that NUI is a non-exempt holding company under PUHCA following restructuring. We also conclude, however, that this risk is mitigated by NUI NC Gas' agreement to hold North Carolina ratepayers harmless from any negative consequences of such a finding and its further agreement to subject itself, on a presumptive basis, to conditions imposed by the Commission on non-exempt holding companies in the past. As a result of these agreements by NUI NC Gas, its North Carolina ratepayers are protected both from any immediate adverse impacts on rates and services as well as from any future harm that could result from the formation of a holding company structure. The Commission finds it appropriate to condition its order authorizing the proposed share exchange in this docket on the stipulated ratepayer protective provisions.

In its Petition, NUI NC Gas asserts that the purpose of its establishment of an exempt holding company structure under PUHCA is to more fully segregate its regulated business operations from its unregulated operations. The Petition further indicates that the proposed restructuring will "provide increased organizational, managerial and financial flexibility, and will better position the NUI companies (including NUI NC Gas) to operate in the changing regulatory and economic environment of the natural gas industry."

Company witness Abramovic, in his prefiled direct testimony, testified that the proposed restructuring will benefit NUI by reorganizing its business structure in a manner that is consistent with the existing dichotomy of regulated and unregulated businesses operated by NUI as a whole. According to Mr. Abramovic, such reorganization will simplify the financial and accounting management for NUI's various businesses and will enhance NUI's ability to engage in new unregulated business ventures. Mr. Abramovic further testified that a holding company structure will allow for easier allocation of revenues and expenses between regulated and unregulated entities and will enhance financial reporting, capitalization and debt structuring for NUI's regulated utility businesses. Mr. Abramovic reaffirmed these conclusions in his prefiled rebuttal testimony.

Company witness Abramovic also presented evidence of potential benefits to North Carolina ratepayers that may accrue from the proposed restructuring. These include: (1) lower overall costs associated with the streamlined financial management of the NUI companies; (2) greater financial stability for NUI's public utility operations resulting from the segregation of non-regulated businesses into a different and more distant corporate entity; and (3) the potential for a lower required rate of return on common equity for NUI NC Gas in its next general rate case as a result of lower risk from unregulated operations.

In his prefiled direct testimony, CUCA witness O'Donnell questioned several aspects of Mr. Abramovic's testimony, including his assertions that the proposed restructuring will enhance and simplify NUI's accounting and financial management and that it will avoid any detrimental impact associated with "skewed" financial ratings resulting from increased involvement in unregulated business. Mr. O'Donnell's conclusions in this regard were based on the lack of immediate cost savings associated with the restructuring and the relatively small percentage of NUI's pretax operating income associated with non-regulated businesses. CUCA witness O'Donnell also challenged what he perceived as Mr. Abramovic's conclusion that "flexibility" and "enhanced positioning" to capitalize on business opportunities constituted ratepayer benefits. Finally, Mr. O'Donnell challenged Mr. Abramovic's conclusion that the restructuring could have a beneficial impact on NUI's rate of return requirements in its next general rate case as a result of lowered risk factors on the basis of an NUI Data Response and further expressed concern over the possibility that NUI's debt structure could potentially be adversely impacted by the restructuring.

In his prefiled rebuttal testimony, Mr. Abramovic indicated that no immediately quantifiable projected cost savings were available for the streamlined financial management that would result from restructuring because NUI had no immediate plans to terminate any employees as a result of the restructuring. Mr. Abramovic added, however, that this did not mean that no efficiencies would be gained. To the contrary, Mr. Abramovic testified that such efficiencies and ultimately cost-savings were anticipated from the share exchange (which might later result in quantifiable cost savings to ratepayers). Mr. Abramovic also indicated that while NUI's current percentage of pretax operating income attributable to unregulated business was relatively small (14 percent), NUI's articulated corporate policy was to expand its involvement in unregulated businesses and that this policy had resulted in acquisitions of several new unregulated businesses in the recent past. Thus, in Mr. Abramovic's view, the possibility of skewed financial management figures were a real possibility if NUI's unregulated businesses were not further segregated from its regulated operations. Mr. Abramovic further testified that his comments regarding the ability to capitalize on new unregulated business opportunities were meant to reflect a benefit to NUI as a whole and were not intended to be interpreted as an immediate projected ratepayer benefit associated with the share exchange. Mr. Abramovic indicated that Mr. O'Donnell's conclusion regarding an apparent contradiction in NUI NC Gas' discovery responses over the potential impact of the share exchange on NUI NC Gas' rate of return requirement was the result of Mr. O'Donnell's misinterpretation of the discovery response in question. Finally, Mr. Abramovic testified that the possibility of impacts on NUI's capital structure resulting from the restructuring did not constitute potential detriments to ratepayers and that NUI had considered those potential impacts and was prepared to take appropriate corrective measures if they occurred.

The Proxy Statement attached to Mr. Abramovic's rebuttal testimony as NUI Rebuttal Exhibit AMA-1 also provides a detailed discussion of the possible benefits (and detriments) associated with the share exchange. The Commission takes note of the fact that this Proxy Statement was provided to NUI's shareholders prior to their approval of the proposed share exchange and subject to SEC disclosure and enforcement regulations.

Finally, the Stipulation entered into between the Public Staff and the Company indicates that, after review of NUI NC Gas' Petition and prefiled direct testimony in this proceeding, the Public Staff agreed that "NUI reasonably believes that the proposed restructuring will benefit the Company and may have beneficial impacts on North Carolina ratepayers."

The Commission has carefully reviewed the testimony and exhibits of Company witness Abramovic and CUCA witness O'Donnell, as well as the Stipulation, and concludes that the benefits demonstrated by NUI NC Gas from the proposed restructuring outweigh the potential harms identified in the record. These benefits include simplified accounting and financial management, simplified allocation of revenues and expenses between regulated and unregulated entities, and enhanced and simplified debt structuring, capitalization and financial reporting. It is also apparent from the record in this proceeding that the Company's management has carefully considered this transaction and has reasonably concluded that the benefits of forming a holding company structure outweigh the potential detriments of such a structure in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence for this finding is contained in the Petition, in the prefiled testimony and exhibits of Company witness Abramovic and CUCA witness O'Donnell and in the Stipulation entered into between the Public Staff and the Company. This finding is supported by the evidence and conclusions supporting Findings of Fact Nos. 7 through 13.

In summary, the Commission has previously found, and supported its findings, that:

(1) Under NUI's current corporate structure, its unregulated business operations are subsidiaries of its regulated public utility company – NUI Corporation.

(2) Under NUI's proposed restructuring, the resulting holding company structure will further segregate NUI's regulated utility operations from its unregulated non-utility businesses.

(3) NUI's proposed restructuring will have no effect on the identity of the certificated public utility providing natural gas service to North Carolina ratepayers and the rates, terms and conditions of such service will not change as a result of the proposed share exchange.

(4) North Carolina ratepayers will be held harmless from any detrimental impacts of the proposed share exchange under the ratepayer protective provisions that NUI and the Public Staff have agreed should be made a part of any order approving NUI NC Gas' proposed share exchange.

(5) The benefits demonstrated by NUI NC Gas outweigh the potential harms and risks associated with the proposed transactions.

On the basis of these findings, and the evidence supporting them, the Commission concludes that NUI NC Gas' proposal to form an exempt holding company structure under PUHCA will provide positive benefits to NUI as well as potential benefits to its ratepayers. The Commission also concludes that what risk may be associated with the proposed transaction has been mitigated by the ratepayer protective provisions set forth in the Stipulation between the Company and the Public Staff and the fact that the restructuring will effectively be seamless to North Carolina ratepayers who will see no immediate change in either the entity providing service to them or the rates, terms or conditions of that service after the restructuring. To the extent that any future event associated with or arising out of the share exchange may threaten harm to North Carolina ratepayers, that risk has either been provided for in the stipulated ratepayer protective provisions or is within the jurisdiction and, therefore, ultimate control of this Commission.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding is contained in the Petition and in the prior findings of this Commission.

In the Petition, NUI NC Gas asserts that the issuance of shares by NUI Holding Company in conjunction with the proposed share exchange is exempt from the requirements of G.S. 62-161 and Commission Rule R1-16 under the holding of the North Carolina Supreme Court in State ex rel. Utilities Commission v. Southern Bell Tel. & Tel. Co., 288 N.C. 201, 217 S.E.2d 543 (1975). In that opinion, the North Carolina Supreme Court held that the issuance of shares by a foreign utility with the majority of its operations and assets outside the state of North Carolina is not subject to G.S. 62-161 or Commission Rule R1-16.

In the past, the Commission has determined on several occasions that the issuance of shares by NUI NC Gas, a certificated North Carolina public utility, is not subject to G.S. 62-161 and Commission Rule R1-16 on the basis of the Southern Bell opinion because NUI is a foreign corporation with the majority of its assets and operations outside the state of North Carolina. See, e.g., In the Matter of Applications for Authority to Transfer Control of International Telephone Group, Inc. to NUI Capital Corp., Order Approving Transfer of Control, NCUC Docket No. G-3, Sub 219 (October 14, 1999). In this case, the entity proposing to issue shares, NUI Holding Company, is an unregulated foreign affiliate of NUI NC Gas which is neither certificated to provide nor providing utility service within this state. Under these facts, and in light of its previous rulings, the Commission has no difficulty in concluding that NUI Holding Company's proposed issuance of shares in this instance is not subject to the requirements of G.S. 62-161 and Commission Rule R1-16.

CONCLUSIONS OF LAW

1. Under the relevant statute, G.S. 62-111, the Commission has broad authority to review all aspects of the proposed share exchange, formation of an exempt holding company and transfer of the ultimate ownership of NUI NC Gas' regulated utility assets and operations in North Carolina to that holding company and to balance all potential benefits and costs of the transactions to determine if they should be authorized.

2. Approval should be given to NUI NC Gas' proposed share exchange, formation and transfer only if sufficient conditions are imposed to ensure that they will have no known adverse impact on the rates and service of NUI NC Gas' ratepayers; its ratepayers are protected as much as possible from potential harm; and its ratepayers will receive sufficient benefit from the proposed activities to offset any potential costs, risks and harms.

3. Based on its application of the foregoing standards to the facts of this case, with particular attention paid to the conditions approved herein, the Commission concludes that the requirements of G.S. 62-111 have been met and that the proposed share exchange, holding company formation, and transfer are justified by the public convenience and necessity and should be approved.

IT IS, THEREFORE, ORDERED as follows:

1. That the proposed share exchange, formation of a holding company and the resulting transfer of ultimate ownership of NUI NC Gas' regulated public utility assets and operations in North Carolina to NUI Holding Company are hereby authorized and approved upon the following conditions:

(a) It is assumed, based on representations made by NUI NC Gas and NUI Corporation, that the transfer of 100 percent of NUI NC Gas' outstanding shares to NUI Holding Company, in exchange for a like number of shares of the stock of NUI Holding and the establishment of NUI Holding as NUI NC Gas' parent will not cause NUI Holding to become a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). If NUI Holding, or any of its affiliates, engage in acquisitions or other actions that could require it to become a registered holding company under PUHCA, NUI NC Gas will notify the Utilities Commission at least 30 days prior to filing with the Securities and Exchange Commission (SEC) any application necessary to obtain authorization to take such actions or, where no such application is necessary, at least 60 days prior to taking such actions.

(b) NUI NC Gas and NUI Holding will bear the full risk of any preemptive effects of PUHCA. The previous sentence includes, but is not limited to, an agreement by NUI Holding and NUI NC Gas to take all such actions as the Commission finds are necessary and appropriate to hold North Carolina retail ratepayers harmless from rate increases, foregone opportunities for rate decreases or other effects of such preemption, including filing with and obtaining approval from the SEC for such commitments as the Commission deems necessary to prevent such preemptive effects.

(c) If the SEC concludes that NUI Holding became a registered holding company by virtue of the transfer approved herein, or if NUI Holding or any of its affiliates engage in acquisitions or other actions that could require it to become a registered holding company, NUI Holding is advised, and the Commission finds, that NUI Holding shall be presumptively subject to the PUHCA conditions imposed by the Commission in prior proceedings involving registered holding companies, subject to NUI Holding's right to file for a waiver or modification of such conditions upon good cause shown.

(d) The ratepayers of NUI NC Gas will be held harmless from any detrimental impacts of the proposed share exchange, formation and transfer, and there will be no change in the identity of the certificated public utility providing natural gas service in North Carolina.

2. That the issuance of shares by NUI Holding Company in connection with the proposed share exchange is exempt from the requirements of G.S. 62-161 and Commission Rule R1-16;

3. That NUI NC Gas shall file a written notice in this docket within thirty (30) days after consummation of the transaction approved herein; and

4. That this docket shall remain open for the purpose of receiving the notice required herein above.

ISSUED BY ORDER OF THE COMMISSION.
This the 11th day of January, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg011001.02

DOCKET NO. P-7, SUB 825
DOCKET NO. P-10, SUB 479
DOCKET NO. P-7, SUB 959

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. P-7, SUB 825 DOCKET NO. P-10, SUB 479 In the Matter of Petition of Carolina Telephone and Telegraph Company and Central Telephone Company for Approval of Price Regulation Plan Pursuant to G.S. 62-133.5 DOCKET NO. P-7, SUB 959 In the Matter of Spring Hope to Raleigh and Zebulon InterLATA Extended Area Service	)	ORDER CONCERNING RULE R9-7 EAS AS GOVERNMENTAL ACTION

BY THE COMMISSION: On August 1, 2001, the Commission issued an Order Seeking Comments in these dockets on whether extended area service (EAS) arrangements authorized under Rule R9-7 even fall under the governmental action provision of Carolina Telephone and Telegraph Company's and Central Telephone Company's (collectively, Carolina's) price plan. The Commission concluded that they do not, but believed that it was appropriate to seek comments from interested parties.

The Commission's reasoning was that Rule R9-7 constitutes a comprehensive method by which incumbent local exchange companies (ILECs) may recover their costs for the institution of EAS arrangements mandated by the Commission. Rule R9-7 preexisted the price regulation plans and has been regularly utilized after the price regulation plans were implemented. The price regulation plans make no reference to EAS other than the cryptic and undefined reference to it in passing in the governmental action section. The operative question is what does this phrase in the governmental action section refer to in view of the fact that not all EAS can emanate from the Commission? It was the Commission's belief that this reference can logically only refer to cases by which EAS is mandated outside the usual R9-7 channels. For example, if the General Assembly simply mandated that the ILECs should provide EAS on a county-wide basis, then that would arguably be a good case for the application of the governmental action provision. The Commission can understand that certain ILECs may not find Rule R9-7 as it is written today to be fully satisfactory, but their remedy is to seek changes to Rule R9-7, not to seek to invoke the governmental action provision--which, in any event, is permissive in nature.

Comments

Public Staff agreed with the Commission's reasoning, calling it the most reasonable and appropriate way of reconciling two apparently conflicting regulations while giving proper effect to the provisions of each. Thus, the Public Staff recommended that the Commission clarify the governmental action provision to exclude EAS arrangements arising under Rule R9-7. Furthermore, the Public Staff questioned whether any rule changes were either necessary or appropriate. The Public Staff stated that Rule R9-7 has worked well over the years, and expressed concern that the price plan companies may seek rule changes which would either undermine the principles embodied in the rule or result in discrimination against rate base/rate of return companies or both.

Verizon South, Inc. (Verizon) noted that the governmental action provisions were common to the various price plans. These provisions do not attempt to enumerate all governmental actions but allow for price adjustments generally with a few specific examples. Verizon argued that the application of governmental actions to extended area service was clear and is consistent with Rule R9-7. Prior to implementation of the price regulation plans, financial impacts of EAS changes not addressed by Rule R9-7 could be addressed by comprehensive rate cases; but, since price plan companies no longer file rate cases, financial impacts resulting from EAS changes are intended to be addressed through the governmental action provision. Rule R9-7 reduces, but does not eliminate, the need to seek recovery under the governmental action provision. Whether an extended area service proposal has a specific impact on the telephone industry as a whole or upon any segment of it is an analysis that can be made on a case-by-case basis.

ALLTEL Carolina, Inc. (ALLTEL) argued that the Commission's interpretation of the governmental action provision works a fundamental change in the plan. When it entered into its plan, it believed that this provision was a mechanism to offset exogenous governmental actions having an adverse financial impact and that the enumeration of extended area service under it was plain. Because of the difficulty in projecting costs accurately, ALLTEL believes that it is imperative for the Commission to use its authority to ensure that ILECs are fully compensated when they are required to implement extended area service. The rate additive in its matrix is not always sufficient to enable ALLTEL to fully recover its EAS expenses and avoid revenue losses. This is probably true of other companies. Hence, the matter rises to the level of an impact at least on a segment of the industry. ALLTEL also expressed doubt that, given the level of financial information that would need to be provided, there would be the possibility of double recovery.

Carolina Telephone and Telegraph Company and Central Telephone Company (collectively, Carolina) argued that Rule R9-7 is designed to recover only a telephone company's incremental costs of extended area service, not to recover unusual or unexpected costs associated with extended area service; nor the recovery of toll loss, access revenue loss, or expanded local calling area revenue loss. This was adequate under rate base/rate of return regulation because a company could always seek recovery in a general rate case; but price plan companies do not have that option. Carolina entered into a stipulation with the Public Staff which includes a governmental action provision with a specific reference to extended area service. This provision is intended to provide companies under price regulation an alternative means of recovering "unusual and unexpected costs and revenue losses incurred in implementing EAS" not otherwise recoverable under Rule R9-7. Price regulation is, as the Commission itself noted, "a form of regulation entirely distinctive and different from traditional rate of return regulation." House Bill 161 specifically contemplates that companies under price regulation are to be allowed to rebalance their rates. The governmental action provision was "designed to consider the full economic impact of establishing EAS." The Commission's view that Rule R9-7 is the exclusive means to recover EAS costs is erroneous. Administering extended area service pricing under the governmental action provisions need not inhibit the expansion of extended area service or otherwise require alteration of matrix rates or other relevant procedures under Rule R9-7, but will only require the application of the criteria set out in the governmental action provision. In entering into price regulation, Carolina made a basic good-faith compact with the Commission and the Public Staff, but the Public Staff, Attorney General, and the Commission have taken positions that frustrate the fair and reasonable application of this provision.

BellSouth Telecommunications, Inc. (BellSouth) noted that the price plans were enacted comparatively recently but Rule R9-7 goes back much further in time and has not ben recently updated. The extended area service rules appear to be somewhat inconsistent with the price regulation plans and also fail to recognize Expanded Local Calling Plans. Most extended area service requests fall within the Expanded Local Calling Plan areas, but community of interest factors and percentage making calls criteria in Rule R9-7 were formulated in a toll environment. Toll calling studies are outdated because most extended area service routes do not involve toll calling. BellSouth therefore encouraged the Commission to undertake a full-blown reexamination of Rule R9-7.

Reply Comments

Public Staff stated that nothing in the comments of other parties dissuaded the Public Staff from its view that the conclusion reached by the Commission in this matter is the most reasonable way of reconciling Rule R9-7 and the governmental action provision. The provisions of Rule R9-7 are sufficient to prevent any undesirable financial effects to the companies from implementing EAS, and the rules by their terms provide for extenuating circumstances. With respect to the argument that, under rate of return regulation, financial impacts of EAS arrangements not addressed under the Rule could have been addressed in a general rate case--something that price plan companies cannot avail themselves of--this is more theoretical than real. Commissions records show that none of the current price plan companies filed general rates cases between 1988 and 1996, although together they implemented a total of 107 EAS arrangements (33 for BellSouth; 43 for Carolina; 14 for Central; 7 for Verizon (formerly, GTE); and 7 for ALLTEL. This undercuts the argument that EAS increments, particularly those determined under matrix tariffs, have failed to recover EAS costs and revenue losses. Indeed, the trend is downward in EAS arrangements since the price plans were adopted. In the past five years, there have been a total of 18 (including 3 for BellSouth, 9 for Carolina, 2 for Central, 2 for Verizon and 2 for ALLTEL. Thus, the parties are hardly disadvantaged under Rule R9-7. Moreover, continued operation under the Rule does not infringe upon rebalancing as authorized under G.S. 62-133.5(a). All the price plan companies have used rebalancing; that they have not used it more may be because competition, which is supposed to force rebalancing, has not developed as anticipated. Finally, the Public Staff noted that, when the price plans were presented, the Commission modified the governmental action provisions to be permissive rather than mandatory and to be pursuant to the public interest. The companies accepted these changes. Thus, the likelihood that the Commission could and would view earnings levels as a facet of the public interest in considering governmental action requests cannot have been entirely unexpected.

Carolina argued that the plain meaning of "EAS arrangements" would include all EAS arrangements, not simply those mandated outside of usual Rule R9-7 channels. Carolina also maintained that the meaning of "any segment" as used in the price plan would refer to any of the Sprint companies. A segment need not refer to more than one company. In any event, the implication of the matter before the Commission reaches beyond a single company. EAS arrangements can have a negative financial impact on Carolina and the price regulation plan was designed to provide some protection from governmental action and inflation. Carolina also pointed out that if the term "segment" is interpreted so as not to apply to a single company, it would follow that governmental actions that provide a benefit to a specific company will not require the company to reduce prices and flow those benefits to consumers.

Verizon stated that it disagreed with the Public Staff's comments and believed that there would be discrimination against price plan companies because they could not avail themselves of a rate case to recover monies in addition to those under Rule R9-7. Verizon also endorsed BellSouth's recommendation that Rule R9-7 may need to be reexamined if the governmental action provision is not deemed to apply to EAS enacted under the rule.

ALLTEL restated its view that the governmental action provision was available to enable companies to recover costs they cannot recover under Rule R9-7, observing that rate base/rate of return companies can recover such monies by way of rate cases. The underlying principle is that the Commission should allow full cost recovery for EAS.

The Alliance of North Carolina Independent Telephone Companies (Alliance) supported Carolina's interpretation of the governmental action provision. The Alliance cited three underlying reasons: (1) carriers in a competitive marketplace need the ability to reasonably adjust their rates to recover revenue losses they cannot control; (2) denial of recovery for EAS could "threaten the long term financial stability" of the local exchange companies; and (3) it should be clear that the governmental action provision, by reference to EAS, was intended to allow for the recovery of EAS revenue losses.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that it should uphold its conclusion in the August 1, 2001 Order in these dockets in which the Commission found that EAS arrangements authorized under Rule R9-7 do not fall under the governmental action provision of Carolina's price plan. In a nutshell, the Commission's reasoning was that Rule R9-7 constitutes a comprehensive method by which ILECs may recover their expenses for the institution of EAS arrangements mandated by the Commission and that this rule pre-existed the price plans and was not modified or superseded by them. The operative question is the meaning of the reference to EAS in the governmental action provision. The Commission's view was that it would logically only refer to EAS arrangements enacted through other means, as, for example, by direct action of the General Assembly.

Before examining the major arguments that ILECs have interposed against this reasoning, it is useful to refer to Rule R9-7 to appreciate how comprehensive it is meant to be in the matter of consideration of costs. There are two methods by which EAS additives can be calculated--cost studies or the application of a matrix rating plan. Generally speaking, the EAS policy allows only for the recovery of incremental costs through these methods. Rule R9-7(e)(1) reads in relevant part:

> Past Commission practice in developing applicable rate increases has generally allowed consideration of only the incremental equipment costs necessary to provide the EAS in question. As a general rule, the Commission has not authorized telephone companies to consider lost toll revenues in developing applicable EAS charges.

However, Rule R9-7(e)(1) contains important exceptions. Companies that have matrix plans can utilize cost studies "under unusual and extenuating circumstances," and lost toll revenues can be recovered if "it can be clearly demonstrated in a particular case that a failure to consider lost toll revenues will in fact result in severe financial distress to the LEC and, in turn, to its remaining local customers." Thus, Rule R9-7 by its terms has built-in safeguards that can lead to the recovery of costs beyond incremental costs.

Turning now to the arguments raised by the various ILECs, the Commission has identified three major ones as follows: (1) the governmental action provision is clear on its face that the costs of EAS arrangements of all sorts are recoverable; (2) the governmental action provision allows for recovery of EAS costs for price plan companies in lieu of the privilege to do so which the companies enjoyed formerly in rate cases; and (3) a single company can be a "segment" of the industry under the terms of the governmental action provision.

The first argument--that the reference to EAS in the governmental action provision plainly refers to EAS arrangements under Rule R9-7--is belied by the fact that there is this controversy. As noted above, Rule R9-7 preexisted the price plans and provides a comprehensive means for the recovery of EAS costs. This is not to say, however, that the reference is meaningless. The logical conclusion, then, is that the term refers to EAS arrangements brought about <u>outside</u> of Rule R9-7. This conclusion is fortified by the fact that instances that give rise to possible recovery under governmental action are generic in nature and are not specific to one company as such.

The second argument is that, in essence, the reference to EAS in the governmental action provision was intended to substitute for price plan companies what the rate case would offer for rate base/rate of return companies–that is, an opportunity to recover expenses not recovered under Rule R9-7. There are several arguments against this view. First, the argument assumes that the reference to EAS in the governmental action provision refers to Rule R9-7 EAS arrangements. This is precisely what is in dispute and which view Commission does not endorse. Second, there is no evidence that the reference to EAS was inserted for that purpose. Indeed, it would be somewhat anomalous. The ILECs are constantly emphasizing how different price regulation is from rate base/rate of return regulation, and that price regulation represents an entirely different type of regulation, yet they now argue that the governmental action provision acts as a functional substitute for what they assert they could obtain in a rate case. In fact, this argument is highly dubious. As the Public Staff pointed out, recovery for EAS expenses in a rate case was more theoretical than real. None of the price plan companies even filed for rate cases in the 1988 to 1996 period when some 107 EAS arrangements were implemented. By contrast, the number of EAS arrangements in the last five years has dwindled dramatically, yet now there appears to be a sudden interest in recovering more than Rule R9-7 would ordinarily (although not necessarily extraordinarily) allow.

Lastly, the ILECs argue that EAS arrangements are recoverable even as to one company as such. However, the language of the governmental action provision refers to actions that have "a specific impact upon the telephone industry as a whole or upon any segment that includes the Company." (Emphasis added). There is a further reference to "general changes." From this language, it is apparent that the governmental action must be one which impacts a class of companies, not simply an individual company as such (as distinct from a company as a member, or even the sole constituent, of a class). Generally speaking, EAS arrangements under Rule R9-7 are specific by the terms to a given company and have no direct financial impact outside of it. By contrast, an EAS arrangement imposed outside of Rule R9-7--such as a legislative mandate to provide county-wide EAS--would clearly be of more general application to a class of companies and more nearly falls within the intent of the governmental action provision. This "general class" requirement, as noted above, in fact strengthens the argument that the reference to EAS in the governmental action provision cannot refer to Rule R9-7 EAS arrangements.

Accordingly, the Commission affirms its tentative conclusion expressed in its August 1, 2001, Order Seeking Comments that EAS arrangements authorized under Rule R9-7 do not fall under the governmental action provision of Carolina's Price Plan and that, therefore, having clarified the meaning of this provision, Carolina's June 1, 2001, Petition Seeking Clarification of EAS Issues is hereby dismissed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of October, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb101601.01

DOCKET NO. P-7, SUB 825
DOCKET NO. P-10, SUB 479
DOCKET NO. P-89, SUB 75

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

<table>
<tr><td>DOCKET NO. P-7, SUB 825
DOCKET NO. P-10, SUB 479

In the Matter of
Petition of Carolina Telephone and Telegraph Company and Central Telephone Company for Approval of Price Regulation Plans Pursuant to G.S. 62-133.5

DOCKET NO. P-89, SUB 75

In the Matter of
AT&T Communications of the Southern States, Inc.
Complainant

v.

Carolina Telephone and Telegraph and Central Telephone Company
Respondents</td><td>ORDER ALLOWING TARIFFS TO BECOME EFFECTIVE, REQUIRING FLOW THROUGH, AND CLARIFYING PROCEDURE</td></tr>
</table>

BEFORE: Chairman Jo Anne Sanford and Commissioners J. Richard Conder, Lorinzo L. Joyner, and James Y. Kerr, II

BY THE COMMISSION: On November 30, 2001, Carolina Telephone and Telegraph Company (Carolina) and Central Telephone Company (Central) filed tariffs to make rate revisions in all three service categories. The purpose of these filings was to propose a decrease in access charge rates, offset by increases in basic exchange rates and optional services from the Interconnection and Non-Basic 1 service categories.

<u>Carolina</u>

In the Basic category, Carolina proposed a rate increase in individual line rates for both business and residential customers. A rate increase was also proposed for key trunks, PBX trunks, and rotary lines. The increase in basic exchange rates resulted in increases for other services, which are tied to basic rates, such as ISDN lines, Network Access Registers (NARs), Centrex Station Line/PBX Differential and Optional Local Measured Service. The proposed increases for residential customers will apply only to rate groups 1-13. The increases in basic local rates will result in an annual revenue increase of approximately $5.3 million. Carolina proposed a rate decrease for the

Carrier Common Line and Local Transport access rates, which will result in an annual revenue decrease of approximately $14.5 million. The net for the Basic category is an annual revenue decrease of approximately $9.2 million. To offset this revenue reduction, Carolina has proposed rate increases that exceed the limits normally applicable to the Interconnection and Non-Basic 1 categories under the price plan, and it has requested a waiver of the separate category constraints of the price plan. In the Interconnection category, Carolina has proposed a rate increase for PSP Access Lines, Toll Terminals and Shared Tenant Service. These proposed rate increases will result in an annual revenue increase of approximately $84,000. In the Non-Basic 1 category, Carolina has proposed rate increases in a variety of services including Local and Toll Operator Assistance, Directory Listings, Foreign Exchange Service, Custom Calling Features, Private Line Channels and Channel Mileage, and some advanced data services. These increases will result in an annual revenue increase of approximately $9.1 million. Across all service categories, these proposed rate changes will result in an annual revenue reduction of approximately $5,100.

Central

Central also proposed increases in individual line rates for business and residential customers. The proposed increase for residential customers will apply only to rate groups 1-12. The increases will produce an annual revenue increase of approximately $600,000. A rate decrease was proposed for the Carrier Common Line and Local Transport Interconnection access rates, producing an annual revenue decrease of approximately $2.1 million. The net for the Basic category is an annual revenue decrease of approximately $1.5 million. Central has proposed to offset this reduction with increases which exceed the limits normally applicable to the Interconnection and Non-Basic 1 categories under the price plan, and it is requesting a waiver of the category constraints of the plan. In the Interconnection category, Central proposed a rate increase for PSP Access Lines, which will result in an annual revenue increase of approximately $7,000. In the Non-Basic 1 category, Central has proposed rate increases in a variety of services, including Extension Mileage, Custom Calling Features, Local and Toll Directory Assistance, Foreign Exchange Service, Local Private Line Service and some advanced data services. These proposed rate increases will produce an annual revenue increase of approximately $1.5 million. Across all services categories, these proposed rate changes will result in an annual revenue decrease of approximately $1,400.

Public Staff's Analysis and Recommendations

This matter was considered at the Regular Commission Staff Conference on December 17, 2001. The Public Staff stated it was not opposed to the companies' request to waive the price plan separate category constraints, noting that the Commission has agreed to similar proposals in order to advance the goal of access charge rate reductions. Overall, the proposed rate changes produce a very slight reduction in total company revenues, and they maintain the required relationship between the PRI and SPI. None of the proposed increases violate the respective category rate element constraints or the requirement that an individual rate element be increased only once during the plan year. In accordance with the notification requirements of the price plan, notice of the proposed rate increases was provided to all affected customers through bill inserts.

The Public Staff, therefore, requested that the Commission issue an Order requiring all facilities-based long distance carriers to file tariffs, along with any required supporting workpapers, to reflect a dollar-for-dollar flow through of the access charge reductions proposed by Caroling and Central. According to the Public Staff, this is consistent with the Commission's Order issued on September 26, 2000, in Docket No. P-55, Subs 1013 and 1161 and Docket No. P-100, Sub 72, in which access charge reductions for BellSouth were required to be flowed through by the facilities-based long distance carriers. Companies with reductions in access charge expenses that are de minimis and administratively burdensome to accomplish may submit letters attesting to such.

Accordingly, the Public Staff recommended that the tariffs implementing the rate changes should be allowed to become effective on January 1, 2002, and that the facilities-based long distance carriers should be required to file tariffs by January 15, 2002, to be effective January 1, 2002, to flow through the access charge reductions on a dollar-for-dollar basis in accordance with the Commission's June 15, 1999 Order in Docket No. P-100, Sub 72.

Mr. John Policastro of AT&T Communications of the Southern States, Inc. (AT&T) stated that AT&T had filed a Notice of Withdrawal of Complaint in Docket No. P-89, Sub 75 and acknowledged that these matters were related to it.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

After careful consideration, the Commission concludes that the proposed tariffs implementing rate changes should be allowed to become effective on January 1, 2002, and that the facilities-based long distance carriers should be required to file tariffs by January 15, 2002, to be effective January 1, 2002, to flow through the access charge reductions on a dollar-for-dollar basis in accordance with the Commission's June 15, 1999 Order in Docket No. P-100, Sub 72. Companies with reductions in access charge expenses that are de minimis and administratively burdensome to accomplish may submit letters attesting to such.

Furthermore, the Commission wishes to express concern about the procedure that was chosen by the companies to present this matter to the Commission. It is both obvious and undisputed that the rate adjustments, particularly the access charge reductions, were related to the resolution of the AT&T complaint in Docket No. P-89, Sub 75. The latest activity in that docket was AT&T's September 6, 2001 Notice of Withdrawal of Complaint, which, however, was not acted upon by this Commission since the Commission anticipated that the parties would thereupon file and request approval of a stipulation regarding their agreement. The Commission strongly believes that filing the stipulation or agreement first is the better practice and admonishes parties entering into future stipulations to present those stipulations to the Commission for our review and approval prior to submitting tariffs that would effectuate those stipulations. In the instant case, in order to at least partially remedy our concerns, the parties shall file, by no later than December 31, 2001, in Docket No. P-89, Sub 75, the text of their stipulation or agreement in settlement of that complaint. Upon review of same, the Commission will issue an Order allowing withdrawal of the Complaint, entering its dismissal, and closing the docket.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

pb121801.02

DOCKET NO. P-294, SUB 23

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Petition of Sprint Communications Company L.P. for	)	
Arbitration with BellSouth Telecommunications, Inc.	)	RECOMMENDED
Pursuant to Section 252(b) of the Telecommunications	)	ARBITRATION ORDER
Act of 1996	)	

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on January 22, 2001

BEFORE: Commissioner Sam J. Ervin, IV, Presiding, and Commissioners Judy Hunt and Robert V. Owens, Jr.

APPEARANCES:

For Sprint Communications Company L.P.:

Jack Derrick, Senior Attorney, Sprint Communications Company L.P., 14111 Capital Boulevard, Wake Forest, North Carolina 27587

William R. Atkinson, Sprint Communications Company L.P., 3100 Cumberland Circle, Atlanta, Georgia 30030

For BellSouth Telecommunications, Inc.:

Edward L. Rankin, III, General Counsel-NC, BellSouth Telecommunications, Inc., Post Office Box 30188, Charlotte, North Carolina 28230

Kip Edenfield, General Attorney, BellSouth Telecommunications, Inc., 675 West Peachtree Street, Suite 4300, Atlanta, Georgia 30305

For the Using and Consuming Public:

Lucy E. Edmondson, Staff Attorney, and Robert S. Gillam, Staff Attorney, Public Staff - North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

BY THE COMMISSION: This matter is before the Commission pursuant to Sections 251 and 252 of the Telecommunications Act of 1996 (TA96 or the Act), G.S. 62-110(f1), and various Commission Orders, on a petition of Sprint Communications Company L.P. (Sprint), requesting the Commission to arbitrate unresolved issues that arose in negotiations with BellSouth Telecommunications, Inc. (BellSouth) for an Interconnection Agreement (Agreement).

BACKGROUND

Section 251 of TA96 requires each incumbent local exchange carrier (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 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 pursuant to the Act.

On August 28, 2000, Sprint filed a Petition for Arbitration, with an issues matrix and the testimony of Melissa L. Closz, Angela Oliver, Mark G. Felton, and David T. Rearden.

On August 24, 2000 (prior to the filing of the petition), BellSouth and Sprint filed a joint motion to transfer certain issues in the arbitration to generic proceedings currently pending before the Commission. An Order transferring these issues was issued on August 28, 2000. On September 11, 2000, BellSouth filed a motion to transfer certain additional issues to pending generic proceedings. Sprint responded to this motion on September 18, 2000, and on September 20, 2000, the Commission transferred the issues in accordance with the motion.

On September 12, 2000, the Commission issued an Order setting this matter for hearing beginning on January 22, 2001, and adopting other procedural requirements.

On September 22, 2000, BellSouth filed its Response to Sprint's Petition for Arbitration, an issues matrix, and the testimony of John A. Ruscilli.

On October 13, 2000, Sprint filed the rebuttal testimony of Melissa L. Closz, Angela Oliver and Mark G. Felton.

On January 16, 2001, the Public Staff filed its Notice of Intervention.

The Commission issued a Prehearing Order on January 18, 2001.

Initially there were 26 issues in dispute between the parties. As a result of the referral of certain issues to generic proceedings and the settlement of other issues, the number of issues currently in dispute has been reduced to three. At the hearing, which was held as scheduled on January 22, 2001, the prefiled testimony of Sprint witness Rearden was not admitted, because all of the issues he addressed had been resolved.

WHEREUPON, based on the foregoing and the entire record in this matter, the Commission now makes the following

FINDINGS OF FACT

1. BellSouth is required to make stand-alone Custom Calling Services and other vertical features available to Sprint for resale at the applicable wholesale discount rate.

2. Sprint may designate its own points of interconnection (POIs) with BellSouth's network. Further, if Sprint interconnects at points within the local access and transport area (LATA) but outside of BellSouth's local calling area from which traffic originates, Sprint should be required to compensate BellSouth for, or otherwise be responsible for, transport beyond the local calling area.

3. BellSouth shall determine the reasonable cost for performing the modifications necessary to permit the same trunk groups to transport traffic from multiple jurisdictions. BellSouth shall provide Sprint with two-way trunking when technically feasible and when there is insufficient traffic to justify one-way trunks.

4. The issue of whether voice-over-Internet (IP telephony) traffic should be included in the definition of "Switched Access Traffic" was settled after the hearing by Sprint and BellSouth.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

MATRIX ISSUE NO. 2: Should BellSouth make its Custom Calling Features/ Services and other vertical features/services available for resale on a stand-alone basis and at the applicable wholesale discount rate?

POSITIONS OF PARTIES

SPRINT: Yes. BellSouth should be required to permit Sprint to purchase Custom Calling Services and other vertical features for resale on a stand-alone basis and at the applicable wholesale discount rate without also requiring Sprint to purchase basic local service.

BELLSOUTH: No. BellSouth agrees to make available for resale any telecommunications service that BellSouth offers on a retail basis to BellSouth's end-user customers. As BellSouth does not provide Custom Calling Features to BellSouth end-users on a stand-alone basis, BellSouth will not make them available to Sprint for resale on a stand-alone basis.

PUBLIC STAFF: No. BellSouth is not required to make vertical features (Custom Calling Features) available to Sprint at wholesale rates on a stand-alone basis.

DISCUSSION

This issue concerns whether the Commission should require BellSouth to permit Sprint to purchase Custom Calling Services and other vertical features for resale on a stand-alone basis and at the applicable wholesale discount without also requiring Sprint to purchase basic local service.

Custom Calling Services are optional features, such as call waiting and call forwarding, available to end-users which enhance the functionality of basic local exchange service. Sprint contended that, under Section 251(c)(4) of the Telecommunications Act of 1996 (the Act), BellSouth is required to "offer for resale at wholesale rates *any* telecommunications service that the carrier provides at retail to subscribers who are not telecommunications carriers." [Emphasis added.] Sprint stated that Custom Calling Services and other vertical features are clearly "telecommunications services" under the definition set forth in the Act[1], and, just as clearly, BellSouth provides Custom Calling Services and other vertical features at retail to end-users who are not telecommunications carriers.

Sprint asserted that BellSouth witness Ruscilli admitted that Custom Calling Services are described as "optional services" on BellSouth's web site, that end-users are charged extra for Custom Calling Services, and that the monthly recurring rates for these services are shown as a separate line item on BellSouth's customers' bills. Sprint noted that witness Ruscilli also agreed that it is technically feasible to offer Custom Calling Services on a stand-alone basis.

Therefore, for the foregoing reasons, Sprint argued that Custom Calling Services are the kinds of services BellSouth is obligated to offer to Sprint and other competing local providers (CLPs) for resale at the applicable wholesale discount. Sprint further argued that its position in this regard was further supported by the Federal Communications Commission's (FCC's) Local Competition Order,[2] at paragraph 871, which states in pertinent part as follows:

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1 See 47 U.S.C. 153(46): "The term 'telecommunications service' means the offering of telecommunications for a fee directly to the public, or to such classes of users as to be effectively available directly to the public, regardless of the facilities used."

2 *In the Matter of Implementation of the Local Competition Provisions in the Telecommunications Act of 1996*, First Report and Order, CC Docket Nos. 96-98, 95-185, FCC No. 96-325 (1996) ("Local Competition Order").

> We conclude that an incumbent LEC must establish a wholesale rate for <u>each</u> retail service that: (1) meets the statutory definition of a "telecommunications service"; and (2) is provided at retail to subscribers who are not "telecommunications carriers". [Emphasis added.]

Sprint observed that other state commissions have recently determined that incumbent local exchange carriers (ILECs) must offer to CLPs vertical features for resale on a stand-alone basis and at the applicable wholesale discount. For example, according to Sprint, the California Public Utilities Commission (California PUC) has ordered Pacific Bell (Pacific) to provide stand-alone vertical features to Sprint at wholesale rates, holding: [1]

> The vertical services Sprint wants to purchase from Pacific are clearly telecommunications services, not enhanced services. Sprint, operating as a CLEC, is entitled to purchase retail telecommunications services at a wholesale discount. It is irrelevant what use Sprint plans to make of the vertical features it purchases for resale . . . .
>
> [E]ven if Sprint is able to purchase the call forwarding service it needs from Pacific's CNS [Complementary Network Services] tariff, that does not eliminate Pacific's obligation under Section 251(c)(4) to offer for resale any service which it offers at retail. <u>Custom calling features fall under that requirement and must be resold, even if Pacific provides the underlying access line</u>. [Emphasis added.]

BellSouth's position is that Sprint's request is contrary to BellSouth's tariff language[2] that would, according to BellSouth, prevent Sprint from purchasing Custom Calling Services except where Sprint also purchases the underlying basic local exchange service. According to Sprint, BellSouth's action in this regard is contrary to the plain meaning of Section 251(c)(4) of the Act and paragraph 939 of the Local Competition Order which states unequivocally that "resale restrictions

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[1] See California PUC Final Arbitrator's Report, Application 00-05-053, September 5, 2000, at 25 (adopted by California PUC October 5, 2000).

[2] Section A13.9.2(B) of BellSouth's General Subscriber Service Tariff states in pertinent part that ". . . Custom Calling Services are furnished only in connection with individual line residence and business main service . . . ."

are presumptively unreasonable" including "conditions and limitations contained in the incumbent LEC's underlying tariff."[1] Sprint argued further that Custom Calling Services are retail services regardless of whether BellSouth has a restriction in its tariffs that these services may only be purchased in conjunction with another retail service. According to Sprint, as explained by its witness Felton, the product is the vertical feature, and the purchase of local dial tone from BellSouth is only the prerequisite condition which must be met before the customer can purchase the vertical feature. Sprint stated that, contrary to BellSouth's claims, BellSouth's condition for the purchase of a product is distinct from the product itself. In support of this contention, Sprint noted that the Texas Public Utility Commission (Texas PUC) has recently declared that tying the purchase of separately tariffed vertical services to the purchase of local service is an unreasonable restriction on resale. See Texas PUC Docket Nos. 21425, 21475, *In Re Complaint by AT&T Communications of the Southwest, Inc. Regarding Tariff Control Number 21311, Pricing Flexibility – Essential Office Packages*, Order (issued December, 2000), at 3:

> When considering only the vertical services offered in Essential Office, [Southwestern Bell's] dominance and control over the market is evident. SWBT currently restricts customer choice through resale restrictions by tying local services to the purchase of its vertical services. The Commission is mindful of the need to promote competition in the expanding vertical services market. Both [the Texas statute] and the [Telecommunications Act of 1996] require the wholesale availability of vertical services without the imposition of unreasonable or discriminatory resale restrictions. As evidenced by the statutory mandates in this case, resale availability is a critical component to wholesale competition of vertical services. Allowing the resale of vertical services without restrictions is a step toward a telecommunications market unhindered by the dominance of any carrier. For these reasons, the Commission has determined that tying the purchase of separately tariffed vertical services to the purchase of local service is unreasonable.

Sprint contended that BellSouth's tariff language need not be modified for the Commission to grant Sprint the remedy Sprint is seeking. According to Sprint, there is no need to alter the

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[1] More fully, Paragraph 939 of the Local Competition Order provides in pertinent part as follows: "We conclude that resale restrictions are presumptively unreasonable. Incumbent LECs can rebut this presumption, buy only if the restrictions are narrowly tailored. Such resale restrictions are not limited to those found in the resale agreement. They include conditions and limitations contained in the incumbent LEC's underlying tariff. As we explained in the NPRM, the ability of incumbent LECs to impose resale restrictions and conditions is likely to be evidence of market power and may reflect an attempt by incumbent LECs to preserve their market position. In a competitive market, an individual seller (an incumbent LEC) would not be able to impose significant restrictions and conditions on buyers because such buyers turn to other sellers. Recognizing that incumbent LECs possess market power, Congress prohibited unreasonable restrictions and conditions on resale. We, as well as state commissions, are unable to predict every potential restriction or limitation an incumbent LEC may seek to impose on a reseller. Given the probability that restrictions and conditions may have anticompetitive results, we conclude that it is consistent with the procompetitive goals of the 1996 Act to presume resale restrictions and conditions to be unreasonable and therefore in violation of section 251(c)(4)."

language in Section A13.9.2 of the tariff because the tariff restriction contained therein is permissible *as applied to end-users purchasing services out of BellSouth's tariff.* Further, according to Sprint, the restrictive language in Section A13.9.2(B) does not apply to CLPs such as Sprint.

Sprint noted that BellSouth claims that Sprint is essentially asking BellSouth to disaggregate a service that is "bundled" with another service, something BellSouth contends it is not required to do. Sprint commented that, in support of BellSouth's argument, BellSouth witness Ruscilli cited paragraph 877 of the Local Competition Order which states that an ILEC is not obligated "to disaggregate a retail service into more discrete retail services" for the purposes of resale. According to Sprint, BellSouth's reliance on paragraph 877 is unfounded. Sprint witness Felton observed that, although local dial tone is necessary for a vertical feature to function properly, vertical features are not a component of a larger service. Sprint stated that, in fact, in his testimony on this issue, BellSouth witness Ruscilli referred to basic local service and a Custom Calling Service as "two discreet items you're buying". Sprint further stated that, as acknowledged by BellSouth at the hearing in this docket, Custom Calling Services are priced and billed separately from any other service and, therefore, meet the criteria of a retail service.

Sprint stated that BellSouth also contends that Sprint's proposal is problematic in situations where another CLP requests to resell the underlying basic local service. However, according to Sprint witness Felton, no problem would arise in situations where Sprint resold the vertical feature, another CLP resold the basic local service, and the end-user then wished to discontinue purchasing the vertical service from Sprint and instead purchase it from the other CLP. Witness Felton testified that in such situations Sprint would be obligated to relinquish that vertical feature to the other CLP. According to Sprint, a similar resolution would prevail in situations where a CLP purchased unbundled network element (UNE) switching for a customer to whom Sprint is reselling a vertical feature. In such instances, Sprint acknowledged that it would be required to terminate its delivery of the vertical feature to the customer or negotiate with the CLP.

BellSouth argued that its resale obligations are set forth in Section 251(c)(4) of the Act. According to BellSouth, under that provision, BellSouth has "the duty to offer for resale at wholesale rates any telecommunications service that the carrier provides at retail to subscribers who are not telecommunications carriers." BellSouth stated that, in its Local Competition Order, the FCC further refined BellSouth's resale obligations:

> The 1996 Act does not require an incumbent LEC to make a wholesale offering of any service that the incumbent LEC does not offer to retail customers. (¶ 872)[1] . . .

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[1] Paragraph 872 of the Local Competition Order provides in full as follows: "We need not prescribe a minimum list of services that are subject to the resale requirement. State commissions, incumbent LECs, and resellers can determine the services that an incumbent LEC must provide at wholesale rates by examining that LEC's retail tariffs. The 1996 Act does not require an incumbent LEC to make a wholesale offering of any service that the incumbent LEC does not offer to retail customers. State commissions, however, may have the power to require incumbent LECs to offer

.[Footnote added.]

> On the other hand, section 251(c)(4) does not impose on incumbent LECs the obligation to disaggregate a retail service into more discrete retail services. The 1996 Act merely requires that any retail services offered to customers be made available for resale. (¶ 877)[1] [Footnote added.]

Thus, according to BellSouth, under the Act, it is only required to allow Sprint to resell the same services that BellSouth provides to BellSouth's end-user customers. BellSouth stated that it provides such services to its end-user customers in accordance with the terms and conditions set forth in BellSouth's General Subscriber Service Tariff. The specific tariff addressing Custom Calling Features is A13.9. BellSouth argued that there are two subsections of A13.9 that are particularly instructive on this issue: 13.9.1A, which provides that "Custom Calling Services are auxiliary features provided *in addition to* basic telephone service" [Emphasis added.] and 13.9.2B, which provides that "Custom Calling Services are furnished *only in connection with individual line residence and business main service.*" [Emphasis added.] BellSouth stated that Sprint conceded that the tariff requires an end-user customer to have basic local service as a prerequisite for having Custom Calling Features. Therefore, BellSouth argued that the Commission should conclude (1) that BellSouth does not provision Custom Calling Features as a stand-alone service apart from basic local exchange service and (2) since Sprint is only entitled to resell the same services that BellSouth provides to BellSouth's end-users, that Sprint is not entitled to resell Custom Calling Features on a stand-alone basis.

Sprint contended that the restriction is reasonable as to the end-user customer but is unreasonable as to Sprint. BellSouth stated that this argument misses the point of the resale obligation. According to BellSouth, it is not limiting Sprint's right to resell the Custom Calling Features that BellSouth provides to the end-user customer. To the contrary, according to BellSouth, it is only insisting that Sprint resell Custom Calling Features under the same terms and conditions that BellSouth provides those services to BellSouth's end-user customers. BellSouth observed that this same Custom Calling Feature prerequisite can be found in Sprint's General Subscriber Services Tariff

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specific intrastate services.[2089]" Footnote 2089 provides as follows: "*See, e.g.*, Illinois Public Utilities Act, Section 13-505.5."

[1] Paragraph 877 of the Local Competition Order provides in full as follows: "We conclude that the plain language of the 1996 Act requires that the incumbent LEC make available at wholesale rates retail services that are actually composed of other retail services, i.e., bundled service offerings. Section 251(c)(4) states that the incumbent LEC must offer for resale "any telecommunications service" provided at retail to subscribers who are not telecommunications carriers. The resale provision of the 1996 Act does not contain any language exempting services if those services can be duplicated or approximated by combining other services. On the other hand, section 251(c)(4) does not impose on incumbent LECs the obligation to disaggregate a retail service into more discrete retail services. The 1996 Act merely requires that any retail services offered to customers be made available for resale."

(Carolina Telephone and Telegraph Company) 13.3.1(c), which provides that "Custom Calling Services are furnished only in connection with residential individual line, business individual line and key trunk service."

BellSouth stated that, even assuming for the sake of argument that the requirement for Sprint to purchase basic local exchange service in order to resell the Custom Calling Features could be viewed as a limitation, it is reasonable, nondiscriminatory, and narrowly tailored to comport with the requirements of section 251(c)(4) of the Act. BellSouth averred that a BellSouth end-user customer simply cannot obtain Custom Calling Features without the underlying basic local exchange service because the customer cannot use these features without first having dial tone. According to BellSouth, since it is imperative than an end-user have dial tone as a prerequisite to having Custom Calling Features, Sprint's suggestion that the tariff poses an unreasonable limitation on Sprints's ability to resale Custom Calling Features is baseless.

BellSouth commented that, although not binding on this Commission, other regulatory commissions have addressed this issue. Specifically, BellSouth argued that the Commission should find persuasive the decision from the Massachusetts Department of Telecommunications and Energy (Massachusetts DTE),[1] which is based on tariff provisions similar to those of BellSouth's A13.9 tariff. BellSouth noted that the Massachusetts DTE concluded at page 23 of the Order that:

> Verizon does not provide Custom Calling Features on a stand-alone basis to its retail customers, but such services are offered only in conjunction with its basic exchange service. See D.T.E. MA No. 10. The Department notes that, based on the information provided to us by the Parties on this issue, Verizon's refusal to offer vertical features on a stand-alone basis to Sprint at the wholesale discount does not violate the Act or the FCC's Local Competition rules. Therefore, we find that Verizon is not required to offer vertical features at the wholesale discount rate, on a stand-alone basis.

In its Brief, BellSouth further contended that, while Sprint cites the decision of the California PUC as authority for its position, the underlying facts of that decision are distinguishable from the facts in this arbitration. BellSouth stated the California PUC, in its decision, noted that "Pacific cannot claim technical infeasibility because its CNS tariff allows for certain vertical features to be sold without an access line." BellSouth stated that this is clearly not the situation with BellSouth's A.13.9 tariff, which provides that "Custom Calling Services are furnished only in connection with individual line residence and business main service."

Further, BellSouth noted that the California PUC's conclusion that Pacific sold vertical features on a stand-alone basis, at retail, is based on sales to enhanced service providers (ESPs). According to BellSouth, the FCC has held that such sales are not at retail, and therefore, do not trigger the requirement under section 251(c)(4) to resell at a wholesale discount. (*See*, Second Report and Order, *Deployment of Wireline Services Offering Advanced Telecommunications*

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[1] Order, *Petition of Sprint Communications Company, L.P., Pursuant to Section 252(b) of the Telecommunications Act of 1996, for Arbitration of an Interconnection Agreement between Sprint and Verizon-Massachusetts*, D.T.E. 00-54, dated December 11, 2000.

Capability, CC Docket No. 98-147 (rel. Nov. 9, 1999), at paragraph 19.) BellSouth further observed that the FCC has also amended its rules "to clarify that advanced services sold to Internet Service Providers as an input component to the Internet Service Provider's own retail Internet service offering are not subject to the discounted resale obligations of section 251(c)(4)." Thus, BellSouth argued that the Commission should not find the decision of the California PUC to be persuasive.

In conclusion, BellSouth asserted that, consistent with the Act and the FCC rules, the Commission should not require BellSouth to provide Custom Calling Features on a stand-alone basis to Sprint.

The Public Staff agreed with BellSouth on this issue. The Public Staff believes that vertical services and local dial tone together constitute a single telecommunications service. The Public Staff commented that, as Sprint points out, vertical services are priced and billed separately from local dial tone and that it is technically possible for such services to be provided by an entity other than the one who provides dial tone. Such considerations, however, according to the Public Staff, pale in comparison with the simple and obvious fact that vertical services are useless without dial tone.

The Public Staff observed that, by declining to provide stand-alone vertical services to Sprint for resale, BellSouth is not placing Sprint at a competitive disadvantage, since BellSouth does not offer stand-alone vertical services to its own customers either. On the other hand, according to the Public Staff, Sprint would obtain a substantial competitive advantage if it could purchase vertical services at the wholesale discount. The Public Staff stated that it is clear from the evidence presented at the hearing that Sprint's primary reason for seeking to purchase stand-alone vertical services is to incorporate them into its voicemail products, such as unified voice messaging. The Public Staff argued that voicemail is not a telecommunications service as defined in section 3 of the Act and that Sprint's competitors in the voicemail area generally are not telecommunications carriers. The Public Staff argued that, if Sprint could take advantage of its carrier status to purchase stand-alone vertical services at the wholesale discount, it could offer voicemail products at a lower cost than its competitors who are ineligible for the discount. The Public Staff noted that paragraph 995 of the Local Competition Order states: "[I]f a company provides both telecommunications and information services, it must be classified as a telecommunications carrier for purposes of section 251 . . . to the extent that it is acting as a telecommunications carrier."[1] The Public Staff stated, however, that in

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[1] Paragraph 995 of the Local Competition Order in full provides as follows: "We conclude that, if a company provides both telecommunications and information services, it must be classified as a telecommunications carrier for the purposes of section 251, and is subject to the obligations under section 251(a), to the extent that it is acting as a telecommunications carrier. We also conclude that telecommunications carriers that have interconnected or gained access under sections 251(a)(1), 251(c)(2), or 251(c)(3), may offer information services through the same arrangement, so long as they are offering telecommunications services through the same arrangement as well. Under a contrary conclusion, a competitor would be precluded from offering information services in competition with the incumbent LEC under the same arrangement, thus increasing the transaction cost for the competitor. We find this to be contrary to the pro-competitive spirit of the 1996 Act. By rejecting this outcome we provide competitors the opportunity to compete effectively with the incumbent by offering a full range of services to end users without having to provide some services inefficiently through distinct facilities or agreements. In addition, we conclude that enhanced service providers that do not also provide domestic or international telecommunications, and are thus not telecommunications carriers within the

purchasing vertical services for incorporation into voicemail products, Sprint is not acting as a telecommunications carrier.

The Public Staff stated that its position on this issue is consistent with that of the Massachusetts DTE decision, which has been previously discussed. The Public Staff also commented that it recognized that Sprint's position is supported by the previously mentioned decision of the California PUC and to some extent by the previously mentioned decision of the Texas PUC. However, the Public Staff asserted that it did not find those decisions persuasive. Accordingly, the Public Staff recommended that the Commission hold that BellSouth is not required to make vertical services available to Sprint at wholesale rates on a stand-alone basis.

The fundamental questions to be resolved here may be stated as follows: Are vertical features "telecommunications services" as defined by the Act? And is BellSouth's tariff language an unreasonable restriction on resale?

Sprint asserted that vertical services are telecommunications services under the definition set forth in the Act. BellSouth does not appear to contend otherwise per se.[1] However, the Public Staff seems to argue that vertical services standing alone are not telecommunications services. In its Proposed Recommended Arbitration Order, the Public Staff stated that ". . . vertical services and local dial tone together constitute a single telecommunications service." [Emphasis added in original.] Presumably then, the Public Staff is arguing that vertical services standing alone are not telecommunications services as defined by the Act. The Commission disagrees.

Section 3(a)(2)(51) of the Act defines "telecommunications service" as follows: "The term 'telecommunications service' means the offering of telecommunications for a fee directly to the public, or to such classes of users as to be effectively available directly to the public, regardless of the facilities used." Vertical features are clearly types of telephonic communication — or stated alternatively, forms of telecommunications — which are offered for a fee by BellSouth directly to the public, and as such constitute "telecommunications services", notwithstanding the fact that dial tone[2] is required to deliver such services and the fact that certain of BellSouth's tariff provisions provide that Custom Calling Services are auxiliary features furnished only in connection with individual line residence and business main service. Therefore, in consideration of the foregoing and

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meaning of the Act, may not interconnect under section 251."

[1] As previously indicated, BellSouth does strongly object to Sprint's request that the Commission require BellSouth to make Custom Calling Services and other vertical features available for resale on a stand-alone basis at the applicable wholesale discount rate. However, BellSouth's justification underlying its position is premised on arguments other than a claim to the effect that Custom Calling Services and other vertical features are not telecommunications services per se under the definition set forth in the Act.

[2] The phraseology "regardless of the facilities used" as set forth in the Act's definition of "telecommunications services" makes it abundantly clear that the facilities through which services are provided are not relevant to the determination of whether any given service is to be considered a "telecommunications service". Therefore, in deciding whether, for example, Custom Calling Services are "telecommunications services" within the meaning of the Act, the fact that dial tone, or more specifically the facilities used in providing dial tone, is needed to provide such vertical features is simply not relevant.

the entire evidence of record, particularly the evidence offered by Sprint which the Commission finds to be the most persuasive, the Commission concludes that Custom Calling Services and other vertical features are "telecommunications services" under the definition set forth in the Act.

The foregoing conclusion is entirely consistent with the previously mentioned Opinion of the California PUC, which the Commission finds to be persuasive. BellSouth and the Public Staff state that the Commission should not find that Opinion persuasive. While the Public Staff offers no argument in support of its position, BellSouth stated that the underlying facts of the California PUC Opinion are distinguishable from the facts in this arbitration. Indeed, the Commission agrees that certain facts before the California PUC on this issue may not be germane and/or may not be perfectly analogous to those in the present proceeding in all respects. However, many, if not most, of the facts and/or sub-issues are, and on balance, the Commission is of the opinion that the reasoning and analysis set forth in the Final Arbitrator's Report (FAR) and the California Opinion provide useful and meaningful information and insight that is worthy of careful consideration by the Commission in ruling on this issue. More specifically, the Commission does not find the arguments presented by BellSouth in its attempt to distinguish the facts in the California Opinion from those presented in this arbitration particularly convincing.

As previously noted, BellSouth contended that the underlying facts of the California decision are distinguishable from the facts in this arbitration. In support of that position, BellSouth argued as follows: First, BellSouth opined that

> . . . the California PUC in its Opinion notes that "Pacific cannot claim technical infeasibility because its CNS tariff allows for certain vertical features to be sold without an access line." Clearly, that is not the case with BellSouth's A.13.9 tariff, which provides that "Custom Calling Services are furnished only in connection with individual line residence and business main service."

Since technical feasibility is not an issue in this proceeding, the Commission can find little, if any, pertinence to the foregoing argument. The fact that BellSouth's tariff provides that "Custom Calling Services are furnished only in connection with individual line residence and business main service" has virtually nothing to do with the fact that it is technically feasible, as all parties agree, for BellSouth to provide Custom Calling Services and other vertical features on a stand-alone basis.

Clearly, the California PUC's statement that "Pacific cannot claim technical infeasibility because its CNS tariff allows for certain vertical features to be sold without an access line," when taken in context, was not intended to show that such services were being offered at retail to end-users, as BellSouth may be suggesting; but rather, it was simply to say that any argument to the effect that it was technically infeasible to provide the subject services was without merit because Pacific, in fact, sold certain vertical features without an access line under its CNS tariff.[1]

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[1] The context in which the California PUC used this language is more fully revealed by the following excerpt from its Opinion:

> We concur with the FAR's determination that Section 251(c)(4) requires the resale of vertical features, without purchase of the associated dial tone. Vertical features meet the Act's

Further, BellSouth argued that

> . . . the California PUC's conclusion that Pacific Bell sold vertical features on a stand-alone basis, at retail, is based on sales to enhanced service providers (ESPs). The FCC has held that such sales are not at retail, and therefore, do not trigger the requirement under section 251(c)(4) to resell at a wholesale discount.

Here again, it appears to the Commission that BellSouth has misconstrued the context and/or the significance of language contained in the California Opinion and/or the FAR.

In addition to commenting on Pacific's CNS tariff in regard to the technical feasibility of providing vertical features on a stand-alone basis, which was discussed above in the context of the California PUC Opinion, the FAR also addressed Pacific's CNS tariff from the viewpoint of whether its provisions adequately fulfilled Sprint's requirements, thereby obviating the need to grant Sprint's instant request. In that regard, the FAR stated as follows:

> In its Comments, Pacific asserts that the language quoted in the DAR [Draft Arbitrator's Report] relating to the use of the CNS tariff was taken out of context. The quoted language is not restrictive, as the DAR concluded, but inclusive, says Pacific; it simply makes it explicit that CNSs are available not only from Pacific on its lines, but are also available on resold lines and can be ordered by ESPs with the authorization of the CLEC leasing the resold line. Pacific clarifies that it provides the services in its CNS tariff to any customer, without any requirement that the customer be required to purchase the underlying exchange service. In other words, Sprint would be able to purchase the call waiting service it wants from that tariff.
>
> However, even if Sprint is able to purchase the call forwarding service it needs from Pacific's CNS tariff, that does not eliminate Pacific's obligation under Section 251(c)(4) to offer for resale any service which it offers at retail. Custom calling features fall under that requirement and must be resold, even if Pacific provides the underlying access line.
>
> In its Comments, Pacific indicates that its resale tariff (175-T, Section 18.5) requires that vertical features offered for resale are only "provided for basic access line services." However, this provision in Pacific's tariff does not overrule the Act's requirements. In this case, the Act must take precedence over Pacific's tariff, since Pacific's tariff clearly is in conflict with the Act.

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requirement of services offered at retail to end-user customers who are not telecommunications carriers. <u>Pacific cannot claim technical infeasibility because its CNS tariff allows for certain vertical features to be sold without an access line, and voice mail providers, including Pacific's affiliate PBIS, purchase those features to provide voice mail service</u>. [Emphasis added.]

Further, we concur with Sprint's assertion that it constitutes an unreasonable restriction under Rule 51.613(b) for Pacific to require that Sprint purchase the dial tone, in order to have access to the vertical services for that line. <u>The CNS tariff gives us ample proof that the two elements do not need to be tied together</u>. [Emphasis added.]

> Given the general resale requirement of Section 251(c)(4), Sprint cannot be precluded from access to a broader range of custom calling features than those found in the CNS tariff. The CNS tariff includes only those features necessary to provide voice mail service. In its Comments, Sprint asserts that it should not have to identify each and every telecommunications service it intends to provide under the ICA [Interconnection Agreement]. It wants to be able to draw on a broad range of vertical features.

The California PUC's Opinion discussed the CNS tariff in the same context as did the FAR, in the foregoing regard. Thus, it is clear to the Commission that the primary, if not the sole, context in which the California Opinion and the FAR discussed Pacific's CNS tariff, in this specific instance, was in the context of ruling on Pacific's assertion that its CNS tariff adequately fulfilled Sprint's requirements, thereby obviating the need to grant the relief requested by Sprint. The California PUC declined to adopt Pacific's position ruling as follows:

> We reject Pacific's assertion that Sprint's proposed resale language should be rejected because it is unnecessary to fulfill Sprint's only identified need for stand-alone vertical features in this arbitration. Sprint identified only one product (Sprint Internet Call Waiting) which it intended to offer, and Pacific asserts that the features it needs are available in Pacific's CNS tariff. Pacific asserts that the FAR goes beyond the mandate of the Act's resale requirements and fails to limit its consideration to the issue presented, as required by § 251 (c)(4). Pacific is incorrect. A review of Sprint's proposed language in Section 2.17 of Attachment Resale reads as follows:
>
> > Resale of Vertical Services. Except as otherwise explicitly provided by Applicable Law, there shall be no restriction on the resale, under § 251(c)(4) of stand-alone vertical services and/or vertical features.
>
> This language makes it clear that Sprint was requesting that all vertical features be made available for resale. [Emphasis added in original.] Sprint's witness mentioned its Internet Call Waiting Service as a sample of a service that Sprint wants to provide, but the specific ICA language Sprint proposed was more general. Therefore, by granting Sprint's language in Section 2.17 (as modified by the FAR), we have not expanded Sprint's request in any way and are not violating Section 252(b)(4).

After having carefully reviewed the language in the California decision regarding Pacific's CNS tariff, including the availability of the tariff to enhanced service providers, the Commission can find virtually no basis to support BellSouth's contention - to any meaningful extent, if at all - that "... the California PUC's conclusion that Pacific Bell sold vertical features on a stand-alone basis, at retail, is based on sales to enhanced service providers." To the contrary, it is the Commission's view that the California PUC reached the subject conclusion for the reasons set forth in the following excerpt from the FAR, to which the California PUC concurred in its Opinion:

> The first issue which must be resolved is whether the vertical services Sprint wants to purchase are subject to the Act's resale requirements. A review of Pacific's

> consumer and business tariffs indicates that Pacific does offer vertical features to end-user customers under its retail tariff. The tariffs also show that Pacific charges separately for vertical services; they are not included in the rate for a basic access line. Therefore, Pacific's assertion that Sprint's request would violate the FCC's ¶ 877 in its *First Report and Order* is not convincing. Pacific is not being asked to disaggregate a bundled service, but to provide a retail service which is listed and priced separately in Pacific's retail tariffs.

The Commission also finds the following excerpt from the California PUC's Opinion insightful:

> According to Pacific, Sprint should not be allowed to negotiate the use of ILEC vertical features for use in offering enhanced services which are unrelated to any interconnection arrangement between the parties. In Pacific's eyes, that is not the proper subject of an ICA. Pacific is incorrect. Sprint is a certificated local service provider in the state of California who wants to offer a unique service to Californians. The vertical services Sprint wants to purchase from Pacific are clearly telecommunications services, not enhanced services. Sprint, operating as a CLEC, is entitled to purchase retail telecommunications services at a wholesale discount. It is irrelevant what use Sprint plans to make of the vertical features it purchases for resale. The lines between so-called "advanced," "enhanced," and basic services are blurring, and we do not further the growth of competition in California by erecting a wall between the various types of services.

In summary, the Commission, after having carefully reviewed the California decision and BellSouth's comments, has found the arguments presented by BellSouth, in its attempt to distinguish certain facts in the California Opinion from those presented in this arbitration, less than convincing. Accordingly, the Commission is of the opinion that it is entirely appropriate for the Commission to consider the FAR and the California Opinion as meaningful precedent in ruling on the present issue.

It is noted that, in this instance and subsequently, the Commission's conclusions are also in keeping with those of the Texas PUC in the case cited by Sprint in support of its position. They are contrary to the ruling of the Massachusetts DTE in the case cited by BellSouth and the Public Staff in support of their positions. In reviewing the Texas decision, the Commission found it to be on point and persuasive, particularly in consideration of the discussion of the rationale underlying the decision as set forth by the Texas PUC in its Order. The Commission, in its review of the Massachusetts decision, found it to be on point but much less persuasive than both the California and Texas decisions. The Massachusetts decision offered much less discussion of the rationale underlying its decision than did the California and Texas PUCs in their respective decisions. Therefore, due to that lack of discussion, very little additional insight could be gleaned from the Massachusetts decision, that is, other than that the positions taken by the parties and the reasoning presented in support of those positions by the parties were quite similar to that presented in this proceeding.

Having concluded that the subject services are "telecommunications services" brings the Commission to the final issue to be resolved: Is BellSouth's tariff language an unreasonable restriction on resale?

Section A13.9.1A of BellSouth's General Subscriber Service Tariff states that "Custom Calling Services are auxiliary features provided in addition to basic telephone service." And, section A13.9.2B states that ". . . Custom Calling Services are furnished only in connection with individual line residence and business main service . . . . " Thus, BellSouth argued that Sprint's request is contrary to BellSouth tariff language that would, according to BellSouth, prevent Sprint from purchasing Custom Calling Services except where Sprint also purchases the underlying basic local exchange service.

As previously noted, Sprint stated that, under Section 251(c)(4) of the Act, BellSouth is required "to offer for resale at wholesale rates any telecommunications service that the carrier provides at retail to subscribers who are not telecommunications carriers" and "not to prohibit, and not to impose unreasonable or discriminatory conditions or limitations on, the resale of such telecommunications service . . . ." Further, Sprint notes that, under certain provisions of the Local Competition Order, the FCC has concluded that resale restrictions are presumptively unreasonable, including conditions and limitations contained in the ILEC's underlying tariff. The FCC also concluded that ILECs can rebut the foregoing presumption, but only if the restrictions are narrowly tailored. In explaining its position in this regard, the FCC stated as follows:

> . . . [T]he ability of incumbent LECs to impose resale restrictions and conditions is likely to be evidence of market power and may reflect an attempt by incumbent LECs to preserve their market position. In a competitive market, an individual seller (an incumbent LEC) would not be able to impose significant restrictions and conditions on buyers because such buyers turn to other sellers. Recognizing that incumbent LECs possess market power, Congress prohibited unreasonable restrictions and conditions on resale. We, as well as state commissions, are unable to predict every potential restriction or limitation an incumbent LEC may seek to impose on a reseller. Given the probability that restrictions and conditions may have anticompetitive results, we conclude that it is consistent with the procompetitive goals of the 1996 Act to presume resale restrictions and conditions to be unreasonable and therefore in violation of section 251(c)(4).[1] [Footnote added.]

Clearly then, under the Local Competition Order, an ILEC is required to bear the burden of proof in showing that its resale restrictions and limitations, if any, are reasonable, nondiscriminatory, and narrowly tailored to comport with the requirements of section 251(c)(4). The Commission is of the opinion that BellSouth has not persuasively rebutted, by the greater weight of the evidence, the presumption that tying local services to the purchase of its vertical services is not an unreasonable or discriminatory resale restriction. The Commission, therefore, concludes that BellSouth's tariff language is an unreasonable restriction on resale.

The principal reasons underlying the foregoing conclusion include the following:

- Custom Calling Services and other vertical features are "telecommunications services" under the definition set forth in the Act.

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[1] See paragraph 939 of the Local Competition Order.

- BellSouth currently provides Custom Calling Services and other vertical features at retail to end-users who are not telecommunications carriers, notwithstanding the fact that such services are not offered on a stand-alone basis but rather are offered only in addition to or in connection with BellSouth's basic local service.

- No party disputes the fact that it is technically feasible for BellSouth to provide the requested services on a stand-alone basis. More specifically, while dial tone is needed to provide vertical features, no party contends that it is technologically necessary for dial tone to be provided by the same carrier that is the provider of vertical services.

- No party disputes that Custom Calling Services are priced and billed separately from dial tone under the provisions of BellSouth's General Subscriber Service Tariff. Indeed, Custom Calling Services are also priced and billed separately when provided in conjunction with unbundled network elements, as reflected in BellSouth's price list summary of its permanent UNE rates currently on file with the Commission.

- BellSouth is not being asked to disaggregate a bundled retail service, but rather is being asked to provide a retail service which is listed and priced separately in its retail tariffs. A bundled service implies that more than one service is being offered for a single price. That is clearly not the case in this instance.

- Sprint is a certified local telecommunications service provider in the state of North Carolina and as such is entitled to purchase retail telecommunications services at a wholesale discount.

- As observed by the California PUC, "[i]t is irrelevant what use Sprint plans to make of the vertical features it purchases for resale . . . ."

- As noted by the Texas PUC, "[a]llowing the resale of vertical services without restrictions is a step toward a telecommunications market unhindered by the dominance of any carrier."

- And last but not least, while this conclusion is clearly supported by the weight of the evidence, most importantly, the Commission is of the opinion that it is mandated by the Act and the FCC's rules.

Based on the foregoing and the entire evidence of record, the Commission finds that BellSouth should be required to make its Custom Calling Services and other vertical features available for resale on a stand-alone basis and at the applicable wholesale discount rate.

CONCLUSIONS

The Commission concludes that, consistent with the Act and FCC rules, BellSouth is required to make stand-alone Custom Calling Services and other vertical features available to Sprint for resale at the applicable wholesale discount rate. Further, BellSouth and Sprint are directed to include language to that effect in their interconnection agreement.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

Matrix Issue No. 7: Should BellSouth be able to designate the network point of interconnection (POI) for delivery of local traffic?

POSITIONS OF PARTIES

SPRINT: Sprint may designate the POI for both receipt and delivery of local traffic at any technically feasible location on BellSouth's network. This right includes the ability to designate the POI for traffic originating on BellSouth's network. In order that CLPs could minimize the cost of transport and termination of traffic and other entry costs and achieve the most efficient network design, Congress and the FCC gave CLPs the ability to designate the POI for the receipt and delivery of local traffic, including BellSouth-originated traffic. The Commission should also reject BellSouth's Virtual Point of Interconnection (VPOI) proposal because it is contrary to law and could dramatically increase costs to Sprint's network deployment plans.

BELLSOUTH: BellSouth offers interconnection in compliance with the requirements of the FCC rules and regulations as well as with any state statute or regulation. Interconnection can be through delivery of facilities to a collocation or fiber meet arrangement or through the lease of facilities. Interconnection for Sprint-originated traffic must be accomplished through at least one point of interconnection within the BellSouth Local Access and Transport Area (LATA) and may be at an access tandem or local tandem. BellSouth, at its option, may designate one or more points of interconnection on its network for the delivery of its originating traffic to Sprint. BellSouth should not be required to incur additional unnecessary cost as a result of the selection of interconnection points by Sprint. If Sprint requires BellSouth to haul BellSouth-originated local traffic from the originating local calling area to a point of interconnection outside that local calling area, Sprint should be financially responsible for the facilities used for that purpose.

PUBLIC STAFF: Each party may designate the POIs for delivery of its originating traffic. A party may establish no less than one POI per LATA and no more than one POI per local calling area. The originating carrier is responsible for the cost of transporting local traffic only up to and including the boundary of the local calling area from which the traffic originated. To the extent that local traffic must be delivered to the terminating carrier at a point outside the local calling area from which the traffic originated, the terminating carrier is responsible for the cost of the transport which extends beyond the local calling area boundary.

DISCUSSION

Sprint witness Closz and BellSouth witness Ruscilli testified on this issue.

In the final analysis, this issue requires a determination of which party, Sprint or BellSouth, will be financially responsible for paying the costs of transporting a call when the POI is within the LATA, but outside the local calling area in which the call originates, and vice versa. When a BellSouth customer in a local calling area originates a call to a Sprint customer within the same local calling area, but the Sprint POI is outside the local calling area of the parties, there remains the question of who incurs the cost of transport facilities. The calls that utilize the facilities in question are calls that originate in one BellSouth local calling area and are intended to be completed in that same local calling area but have to be routed out of that local calling area because of Sprint's network design.

This issue exists because Sprint and BellSouth have each built and intend to utilize totally separate and different networks for the provision of local service in North Carolina. Each carrier's local network was designed to be the most efficient and cost effective for that carrier. BellSouth does not contest Sprint's network design, but contends that Sprint should bear the cost for transport of BellSouth's traffic if Sprint's designated POI is outside of the local calling area where the BellSouth traffic originates. The Public Staff supports BellSouth's position.

The parties interpreted this issue differently. Sprint, which petitioned for arbitration, sought only to have the Commission determine whether BellSouth may designate the POIs for its originating traffic. Sprint witness Closz pointed to paragraphs 172 and 220 of the FCC's Local Competition Order, which provide that CLPs have the right to select technically feasible points to exchange local traffic with an ILEC. She interpreted the word "exchange" to mean both the receipt and the delivery of traffic. The Local Competition Order, witness Closz argued, does not give ILECs any right to designate points of interconnection. Witness Closz explained that designating the POIs for both the delivery and receipt of BellSouth's traffic is important to Sprint because BellSouth could designate its end offices as POIs for its originating traffic and Sprint would be forced either to build facilities or pay to transport BellSouth's originating traffic.

BellSouth witness Ruscilli contended that the issue was whether BellSouth is obligated to provide facilities for local calls transported outside of the local calling area at no charge to Sprint. He explained that BellSouth does not oppose Sprint's plan to establish one POI per LATA, as long as Sprint is willing to assume financial responsibility for the costs associated with the transport of calls from a virtual POI or an end office (whichever Sprint prefers) to the POI, when the calls are in one local calling area and the POI is in another. Witness Ruscilli argued that BellSouth is not requiring Sprint to duplicate its network architecture or to build facilities to each BellSouth end office; however, Sprint cannot shift its financial responsibility to BellSouth by virtue of opting to have only one POI in the LATA.

Section 251(c)(2)(b) of the Act states that it is the duty of every ILEC "to provide for the facilities and any equipment of any requesting telecommunications carrier, interconnection with the local exchange carrier's network . . . at any technically feasible point within the carrier's network." In this case, technical feasibility is not an issue, as the parties agree that Sprint's proposal to establish one POI per LATA is technically feasible without regard to cost. Moreover, in paragraph 199 of the Local Competition Order, the FCC found that "the 1996 Act bars consideration of costs in determining a 'technically feasible' point of interconnection or access." Indeed, this approach is consistent with the FCC's decisions in its Texas[1] and Kansas/Oklahoma[2] proceedings under section 271 of the Act, where the FCC determined that a CLP could choose to interconnect at only one technically feasible point within a LATA.

Generally, each carrier is responsible for the costs of transporting its originating traffic to the POI.[3] Nonetheless, the POI might be outside the local calling area, or even the LATA or state. In paragraph 199 of the Local Competition Order, the FCC determined that a "requesting carrier that wishes a 'technically feasible' but expensive interconnection would . . . be required to bear the cost of that interconnection, including a reasonable profit." In this case, Sprint's proposal to establish only one POI per LATA would force BellSouth to incur additional transport costs to deliver local traffic from every exchange in the LATA to Sprint. This would be tantamount to requiring that BellSouth construct a portion of Sprint's local network at no cost to Sprint.

It is true that paragraph 172 of the Local Competition Order allows "competing carriers to choose the most efficient points at which to exchange traffic with incumbent LECs, thereby lowering the competing carriers' costs of, among other things, transport and termination of traffic." The fact remains, however, that Sprint's choice of POIs also affects BellSouth's costs. The Commission believes that it would be inequitable to allow Sprint to choose POIs that minimize its costs, while ignoring the effect of such a choice on BellSouth, and ultimately on BellSouth's ratepayers.

Sprint, of course, is not required to establish a POI in every local calling area. It has a wide array of choices in locating POIs. Sprint may avoid the cost of transport by establishing a POI in each BellSouth local calling area. It also may have one POI per LATA and pay the transport for calls originating in a local calling area other than that of the POI.

The basic issue here is one of ultimate cost responsibility. The Commission is of the opinion that there is no case or principle that is legally dispositive of the result on this issue. Rather, the law allows, and the greater equity demands, that, if Sprint interconnects at points within the LATA but outside BellSouth's local calling area from which traffic originates, Sprint should be required to compensate BellSouth for, or otherwise be responsible for, transport beyond the local calling area. The Commission believes that this holding does not violate any FCC rule or case law and that is more equitable than not and in the greater public interest. Clearly, there are costs incurred with the transport of calls across local calling areas, thereby resulting in facility cost elements not included in local loop costing and traditional ratemaking. The Commission believes that it would be inequitable to allow Sprint to choose POIs that minimize its costs while ignoring the effect of such choices on BellSouth.

This is not to imply that Sprint should be required to establish a POI in every local calling area. The Commission Staff is aware of several cases that hold that such a requirement is contrary

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[1] SBC Communications, Inc., 15 FCC Rcd. 18,354 (June 30, 2000).

[2] SBC Communications, Inc., CC Docket No. 00-217, 2001 WL 55637 (F.C.C. Jan. 22, 2001).

[3] 47 C.F.R. § 51.703(b).

to TA96 and FCC rules[1], and we concur in that Sprint has a wide array of choices for the location of its POIs. However, when it chooses the site of the POIs, it must consider the total cost of each alternative, not merely the direct costs, but also those costs of BellSouth that should properly be assigned to Sprint. While Sprint may avoid the cost of transport entirely by establishing a POI in each BellSouth local calling area, it certainly may choose instead to have one POI per LATA and pay the transport for calls originating in another local calling area than the one where the POI is located.

The questions addressed above, especially the question of responsibility for transport costs, were also dealt with exhaustively in the AT&T/BellSouth arbitration proceeding (Docket Nos. P-140, Sub 73 and P-646, Sub 7). The issues raised here are clearly analogous to those raised in that proceeding, and there is no need to repeat the Commission's analysis here. That analysis, including the discussion of and conclusions regarding relevant case law as well as the applicability of FCC Rule 51.703(b), is incorporated herein by reference. Accordingly, the Commission believes that the POI and associated transport issues should be resolved in the same way as in the AT&T/BellSouth proceeding.

Lastly, the Commission suggests that Sprint might want to seek clarification of this issue from the FCC, since the FCC has in fact recently solicited comments on this issue (See Notice of Proposed Rulemaking, CC Docket No. 01-92, issued April 27, 2001, ¶¶112-114). This is a further indication to the Commission that the proposition that the CLP should bear no transport costs in this context is less obvious than some parties believe.

CONCLUSIONS

The Commission concludes that, if Sprint interconnects at points within the LATA but outside of BellSouth's local calling area from which traffic originates, Sprint should be required to compensate BellSouth for, or otherwise be responsible for, transport beyond the local calling area. The Commission further concludes that this holding does not violate any FCC rules or case law and that it is equitable and in the public interest. However, if Sprint should feel aggrieved by the ruling in this Order, the Commission suggests Sprint may wish to seek a declaratory ruling from the FCC, so that a more definitive statement of this issue may be received from that source.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

MATRIX ISSUE NO. 8: Should the Parties' Agreement contain language providing Sprint with the ability to transport multi-jurisdictional traffic over the same trunk groups, including access trunk groups?

POSITIONS OF PARTIES

SPRINT: Sprint's request to route multi-jurisdictional traffic over the same trunk group, including

[1] US West Communications, Inc. v. Hix, et al., No. C97-D-152, (D. Colo., June 23, 2000); US West Communications, Inc. v. AT&T Communications of the Pacific Northwest, Inc., 31 F.Supp.2d 839 (D. Or. Dec. 10, 1998), rev'd in part, vacated in part on other grounds, US West Communications, Inc. v. Hamilton, 224 F.3d 1049, (9th Cir.(Or.) September 13, 2000)

access trunk groups, is technically feasible. In the event the parties are unable to resolve the reasonable cost aspects of Sprint's proposal, Sprint requests that the Commission determine reasonable cost upon either party's request. Further, the Commission should require BellSouth to provide two-way trunks for BellSouth-originated traffic. BellSouth is obligated to provide two-way trunks to Sprint at Sprint's request, and to use those same two-way trunks for BellSouth-originated traffic. BellSouth is obligated to provide two-way trunks to Sprint, and if BellSouth does not use those same two-way trunks, the trunks effectively cease to be two-way. In accordance with the applicable FCC rule, Sprint cannot be forced to use one-way trunks against its will.

BELLSOUTH: BellSouth has determined that Sprint's request to establish reciprocal trunk groups in some central offices and place all originating and/or terminating traffic, local or non-local, over direct end office switched access Feature Group D trunks is technically feasible. BellSouth will develop and implement Sprint's request based on Sprint's commitment to pay BellSouth for any and all reasonable development and implementation costs. BellSouth will provide two-way trunking to Sprint upon Sprint's request. However, BellSouth will utilize two-way trunking for BellSouth originated traffic in those instances where it makes economic sense to do so and upon mutual agreement of the parties.

PUBLIC STAFF: BellSouth should determine the cost of performing the modifications necessary to permit the same trunk groups to transport traffic from multiple jurisdictions. If Sprint disputes these changes, the dispute resolution process provided for in the interconnection agreement should resolve the issue. BellSouth is obliged under the FCC's Local Competition Order to accommodate two-way trunking when requested by a CLP and if it is technically feasible and if there is not sufficient traffic to justify one-way trunks.

DISCUSSION

There appear to be two separate parts to this issue: first, whether Sprint may transport traffic from multiple jurisdictions over the same trunk groups and, second, whether BellSouth is required to provide two-way interconnection trunking upon request.

Sprint witness Oliver provided extensive testimony regarding the technical feasibility of transporting traffic from multiple jurisdictions over the same trunk groups. Based upon this information, and the testimony of BellSouth witness Ruscilli, it is clear that such arrangements are technically feasible. However, there is a cost associated with modifying the existing network arrangements. BellSouth is currently attempting to ascertain the cost of such modifications, and Sprint has indicated its willingness to pay this cost, as long as it is reasonable.

The Commission concludes that BellSouth should determine the cost of performing the modifications necessary to permit the same trunk groups to transport traffic from multiple jurisdictions. If Sprint disputes the reasonableness of the costs, the dispute resolution process provided for in the interconnection agreement should be used to resolve the issue.

The second part of this issue concerns the provision of two-way trunks by BellSouth at Sprint's request. According to witness Oliver, Sprint is requesting that BellSouth be required not only to provide two-way trunks at Sprint's request but to use those trunks for BellSouth-originating traffic. Witness Oliver acknowledged that this would effectively prevent BellSouth from choosing its own point of interconnection for its originating traffic.

BellSouth witness Ruscilli testified that BellSouth does not object to providing two-way trunks for use by Sprint. However, BellSouth does object to allowing Sprint to dictate how BellSouth-originated traffic will be routed. Having recently considered and ruled on this issue in the MCI/BellSouth arbitration (Docket No. P-474, Sub 10), the Commission in this case again finds that BellSouth is obligated by the FCC's Local Competition Order to accommodate two-way trunking when requested by a CLP if technically feasible and if there is not sufficient traffic to justify one-way trunks.

CONCLUSIONS

The Commission concludes that BellSouth should determine the reasonable cost of performing the modifications necessary to permit the same trunk groups to transport traffic from multiple jurisdictions. Furthermore, BellSouth must provide Sprint with two-way trunking when technically feasible and there is not sufficient traffic to justify one-way trunking.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

MATRIX ISSUE NO. 11: Should voice-over-Internet (IP Telephony) traffic be included in the definition of "Switched Access Traffic"?

DISCUSSION

By letter filed April 11, 2001, Sprint advised the Commission that the Parties settled this issue (Matrix Issue No. 11) and that the Commission need not resolve the issue for the Parties.

CONCLUSIONS

The Commission notes that this issue has been settled by the Parties and that it is, therefore, not necessary for the Commission to further address and decide this matter.

IT IS, THEREFORE, ORDERED as follows:

1. That Sprint and BellSouth 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 August 6, 2001, 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 August 6, 2001, 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 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 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 5 above, on an MS-DOS formatted 3.5-inch computer diskette containing noncompressed files created or saved in WordPerfect format.

ISSUED BY ORDER OF THE COMMISSION.
This the _5th_ day of July, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

bb062801.01

Commissioner Sam J. Ervin, IV concurs in the result with respect to Matrix Issue No. 7 by separate opinion.

APPENDIX A

GLOSSARY OF ACRONYMS
Docket No. P-294, Sub 23

Act	Telecommunications Act of 1996
BellSouth	BellSouth Telecommunications, Inc.
CLEC	Competitive Local Exchange Company (Carrier)
CLP	Competing Local Provider
CNS	Complementary Network Services
Commission	North Carolina Utilities Commission
DAR	Draft Arbitrator's Report
ESP	Enhanced Service Provider
FAR	Final Arbitrator's Report
FCC	Federal Communications Commission
ICA	Interconnection Agreement
ILEC	Incumbent Local Exchange Company (Carrier)
IP	Internet Protocol
LATA	Local Access and Transport Area
LEC	Local Exchange Company (Carrier)
MCI	MCI Telecommunications Corporation
POI	Point of Interconnection
Public Staff	Public Staff-North Carolina Utilities Commission
RAO	Recommended Arbitration Order
Sprint	Sprint Communications Company L.P.
TA96	Telecommunications Act of 1996
UNE	Unbundled Network Element
VPOI	Virtual Point of Interconnection

DOCKET NO. P-294, SUB 23

COMMISSIONER SAM J. ERVIN, IV, CONCURRING IN THE RESULT: As is apparent from reading the Recommended Arbitration Order in this proceeding, the Commission has required Sprint to bear the cost of delivering BellSouth-originated local traffic from an existing BellSouth local calling area to a point of interconnection designated by Sprint within the same LATA and outside the BellSouth local calling area from which the call originated. I have expressed my concerns about Commission decisions reaching similar results in a number of recent dissents. See: In re Arbitration of Interconnection Agreement Between AT&T Communications of the Southern States, Inc., and TCG of the Carolinas, Inc., and BellSouth Telecommunications, Inc., Docket Nos. P-140, Sub 73, and P-646, Sub 7, Recommended Arbitration Order (March 9, 2001); In re Petition of MCImetro Access Transmission Services, L.L.C., For Arbitration of Proposed Agreement with BellSouth Telecommunications, Inc., Docket No. P-474, Sub 10, Recommended Arbitration Order (April 3, 2001); In re Arbitration of Interconnection Agreement Between AT&T Communications of the Southern States, Inc., and TCG of the Carolinas, Inc., and BellSouth Telecommunications, Inc., Docket Nos. P-140, Sub 73, and P-646, Sub 7, Order Ruling On Objections And Requiring The Filing Of Composite Agreement (June 19, 2001). Although I continue to believe for the reasons set forth in my earlier dissents that the result reached by the Commission with respect to the point of interconnection issue in those earlier proceedings and in this proceeding is contrary to the FCC's interconnection regulations and that the "equity" argument upon which the Commission has repeatedly relied in addressing this issue assumes the point in dispute, supports a different result than the one actually reached, and is not competitively neutral, I also recognize that the full Commission has now spoken definitively with respect to this issue in the AT&T and TCG/BellSouth arbitration proceeding and would undoubtedly reach the same result here if the necessity for doing so were to arise. Such additional proceedings would be a waste of time and resources for both the Commission and the parties. In order to avoid such an outcome, I hereby concur in the result reached by the Commission with respect to the point of interconnection issue in this proceeding, although I reserve the right to reassert the position which I have articulated in my dissents in previous interconnection arbitration proceedings in any matter under consideration by the full Commission now or at any time in the future.

I fully concur in the result reached and the reasoning adopted by the Commission with respect to all other issues in dispute between the parties in this proceeding.

/s/ Sam J. Ervin, IV
Commissioner Sam J. Ervin, IV

DOCKET NO. SP-77, SUB 3
DOCKET NO. SP-100, SUB 20

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

Docket No. SP-77, Sub 3		
In the Matter of Notice of Significant Changes and Request of Westmoreland-LG&E Partners for Re-Issuance of its Certificate of Public Convenience and Necessity or Confirmation of the Continued Validity Thereof for its Roanoke Valley II Project, which is Located at the Site of the Roanoke Valley I Project, a Tract of Land of 113 Acres Located near Roanoke Rapids, and Weldon, North Carolina	)	ORDER ON NOTICE OF SIGNIFICANT CHANGES AND ON REQUEST FOR DECLARATORY RULING
and	)	
Docket No. SP-100, Sub 20	)	
In the Matter of Request for a Declaratory Ruling by Westmoreland-LG&E Partners	)	

BY THE COMMISSION: On February 1, 2001, Westmoreland-LG&E Partners (WLP) filed a notice of significant changes and a request for the reissuance of its certificate of public convenience and necessity or a confirmation of its continued validity (Notice) in Docket No. SP-77, Sub 3. Also on February 1, 2001, WLP filed a request for a declaratory ruling (Request) in Docket No. SP-100, Sub 20. WLP is a general partnership formed in Virginia. It owns the Roanoke Valley I Project (ROVA I) and the Roanoke Valley II Project (ROVA II) near Weldon and Roanoke Rapids, North Carolina, in Halifax County. ROVA I and ROVA II are coal-fired cogeneration facilities, with net power production capacity of approximately 165 MW and 45 MW, respectively, which were certificated by the Commission as qualifying facilities (QFs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). The certificate for ROVA I was issued on September 27, 1990, in Docket No. SP-77, and ROVA II's certificate was issued on December 22, 1992, in Docket No. SP-77, Sub 2.

WLP has notified the Commission that it plans to terminate ROVA II's status as a QF and convert it to Eligible Facility status, and it has asked the Commission to reissue its certificate of public convenience and necessity or confirm the continued validity of the current certificate. It also has asked the Commission for a declaratory ruling that its relinquishment of ROVA II's QF status will not cause it to be regarded as a public utility under North Carolina law with respect to its sale of both electricity and steam, that the certificates for the ROVA facilities are valid and remain in full force and effect, and that WLP and the ROVA facilities will continue to be exempt from public utility regulation.

In 1993, WLP filed a notice with respect to ROVA I indicating that it planned to terminate ROVA I's QF status and convert to Eligible Facility status under the Energy Policy Act of 1992 (EPACT) and that it had applied to the Federal Energy Regulatory Commission (FERC) for status as an Exempt Wholesale Generator (EWG) under EPACT. It further stated that it intended to continue to sell electricity to Virginia Electric & Power Company (NC Power) under its existing purchased power agreement (PPA) and that, because it no longer had a minimum steam obligation to its steam host, Patch Rubber Company (Patch), it requested that it be able to sell steam to up to four additional other industries located, or to be located, in the adjacent industrial park. Because of the foregoing proposed changes, WLP also requested that the Commission declare that its proposed activities would not render it a public utility under North Carolina law.

Based on the facts and representations in WLP's notice and request, and subject to the stipulation and certain stated conditions, the Commission concluded, by Order dated October 13, 1993, that the public convenience and necessity justified the reissuance of ROVA I's certificate and that WLP should not be regarded as a public utility within the meaning of G.S. 62-3(23)(a).

With respect to the currently pending filings and the proposed termination of ROVA II's QF status and its sales of electricity, WLP identifies the following factors that mitigate against subjecting WLP to state regulation as a public utility: (a) WLP sells electricity at wholesale to NC Power and is prohibited from selling electricity to anyone else by its PPAs and its certificates; (b) WLP is not affiliated with NC Power; (c) ROVA II's PPA resulted from a competitive bidding process and arms-length bargaining; (d) the Commission has authority to regulate NC Power's rates and control its selection of generating options through the ratemaking process; and (e) regulating WLP because of its sale of electricity at wholesale will not aid the development of wholesale competition.

With respect to the sale of steam from the ROVA facilities to Patch, WLP identifies the following factors that mitigate against subjecting WLP to state regulation as a public utility: (a) Patch is free to obtain steam supply from other sources; (b) the steam sold to Patch is incidental to the production of electricity; and (c) the agreement between WLP and Patch contains limitation on Patch's use of the steam.

WLP stated in its filing that, if the Commission grants the relief it has requested, it would accept a number of conditions upon its relinquishment of ROVA II's QF status. These conditions would apply to both its electricity sales to NC Power and its steam sales to Patch and to any future steam sales to other tenants in the adjacent industrial park.

The Public Staff presented this matter at the Commission's Staff Conference on March 19, 2001, and recommended that the Commission clarify WLP's proposed conditions in several respects and add a condition stating that ROVA I remains subject to the conditions imposed by the Commission in Docket Nos. SP-77 and SP-100, Sub 2.

Based upon the foregoing, a careful consideration of the filings in these dockets, and the Public Staff's recommendations, the Commission concludes that based on the facts and representations contained in WLP's Notice and Request and subject to the conditions imposed herein, WLP's relinquishment of ROVA II's QF status will not cause WLP to be regarded as a public utility under North Carolina law with respect to its sales of electricity and steam, that ROVA I's certificate will continue to be valid, and that WLP and the ROVA facilities will continue to be exempt from public utility regulation. In addition, the Commission concludes that the public convenience and necessity justify the reissuance to WLP of the certificate for ROVA II in Docket No. SP-77, Sub 2, also subject to the following conditions:

(a) The electricity generated by the ROVA facilities shall be sold to North Carolina Power at wholesale pursuant to the PPAs;

(b) The Commission shall maintain some limited oversight over WLP and its sales of electricity, as contemplated by § 714 of EPACT, 16 U.S.C. § 824(g);

(c) ROVA I remains subject to the conditions imposed by the Commission in Docket Nos. SP-77 and SP-100, Sub 2;

(d) Steam sales will be limited to Patch and up to four other industrial entities located in the adjacent industrial park at a capacity no greater than the ROVA facilities' current capabilities;

(e) Steam sales will involve available steam capacity that is incidental to the production of electricity pursuant to the ROVA facilities' PPAs;

(f) Steam customers will have other energy options, will be free to obtain their steam supply from other sources (including self-generation), and will not be confined to purchasing steam from the ROVA facilities;

(g) Any steam sales will result from freely-bargained-for contracts;

(h) The contract between WLP and Patch provides that Patch can only use the steam it purchases from the ROVA facilities for purposes other than producing electricity and that it cannot resell the steam;

(i) Future contracts, if any, with industrial entities for sales of steam from the ROVA facilities shall prohibit the use of steam for the production of electricity and the resale of steam;

(j) WLP shall file a semi-annual report and a cumulative annual operating report summarizing the ROVA facilities' monthly operating data, including electric output (MWh), capacity factor, availability factor, forced and scheduled outage hours and rate, and fuel consumption (MMBtus and tons); and

(k) WLP shall file an annual operating report summarizing the amount of steam sold from the ROVA facilities and to whom it was sold during the preceding calendar year.

IT IS, THEREFORE, ORDERED as follows:

1. That, based on the facts and representations as set forth herein and in WLP's Notice and Request and subject to the conditions imposed herein, WLP's relinquishment of ROVA II's QF status will not cause WLP to be regarded as a public utility under North Carolina law with respect to its sales of electricity and steam, ROVA I's certificate will continue to be valid, and WLP and the ROVA facilities will continue to be exempt from public utility regulation;

2. That, based on the facts and representations as set forth herein and in WLP's Notice and Request and subject to the conditions imposed herein, the certificate of public convenience and necessity previously issued to WLP for ROVA II in Docket No. SP-77, Sub 2, should be, and hereby is, reissued in accordance with the terms and conditions set forth herein, and the reissued certificate is attached hereto as Appendix A; and

3. That future transfers, assignments, and/or other significant changes in ownership and/or control of ROVA I and II remain subject to the jurisdiction of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

pb032001.02

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. SP-77, SUB 3

Westmoreland-LG&E Partners
c/o Westmoreland-Roanoke Valley, L.P.
2302 Hunters Way,
Charlottesville, Virginia 22911

is hereby reissued this

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
PURSUANT TO G.S. 62-110.1

for a coal-fired cogeneration facility
with a nameplate capacity of 45 MW
to be known as the Roanoke Valley II Project

located

on the site of the Roanoke Valley I Project,
a tract of land of 113 acres located
near Roanoke Rapids and Weldon, North Carolina,

subject to the reporting requirements of G.S. 62-110.1(f), and
subject to all orders, rules, regulations and conditions as
are now or may hereafter be lawfully made by
the North Carolina Utilities Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 21st day of March, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

SMALL POWER PRODUCER - CERTIFICATE

DOCKET NO. SP-77, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Notice of Significant Changes and Request of Westmoreland-LG&E Partners for Re-Issuance of its Certificate of Public Convenience and Necessity or Confirmation of the Continued Validity Thereof for its Roanoke Valley II Project, which is Located at the Site of the Roanoke Valley I Project, a Tract of Land of 113 Acres Located near Roanoke Rapids, and Weldon, North Carolina	)))))))))	ORDER CLOSING DOCKET

BY THE CHAIR: On March 21, 2001, the Commission issued its Order on Notice of Significant Changes and on Request for Declaratory Ruling in the above-captioned docket and in Docket No. SP-100, Sub 20. The latter docket, relating to the request for declaratory ruling, was closed as of the date of the Order, but the above-captioned docket was held open to receive certain reports required in the Order to be filed as a condition of re-issuance of the certificate of public convenience and necessity for the Roanoke Valley II generating facility.

The Chair notes that, pursuant to Commission Order issued October 13, 1993, similar reports regarding the Roanoke Valley I generating facility are being filed in Docket No. SP-77, Sub 0. The Chair is of the opinion that the reports required to be filed in the above-captioned docket by the Commission's March 21, 2001, Order should likewise be filed in Docket No. SP-77, Sub 0, and that the above-captioned docket should now be closed.

IT IS, THEREFORE, SO ORDERED.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg060701.02

DOCKET NO. SP-132
DOCKET NO. EMP-1, SUB 0

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Rockingham Power, LLC for a Certificate of Public Convenience and Necessity to Construct Five Combustion Turbine Generators Located off Highway 65 in Rockingham County, North Carolina	)	ORDER ON REQUEST FOR APPROVAL OF CONTRACT PROVISION

BY THE COMMISSION: On January 29, 1999, Rockingham Power, LLC (Rockingham), an affiliate of Dynegy Power Corporation, filed an application for a certificate of public convenience and necessity pursuant to G.S. 62-110.1 to construct an 800 megawatt combustion turbine electric generating facility in Rockingham County. The application stated that natural gas would be provided by Transcontinental Gas Pipeline Corporation (Transco). NUI Corporation, d/b/a NUI North Carolina Gas (NUI), the local LDC for the site, intervened.

A hearing was held on May 20, 1999, and conflicting testimony was presented as to the issue of bypass of the LDC. A Rockingham witness contended that bypass was not a goal of Rockingham and that Rockingham had contracted with Transco only after learning that NUI did not have the necessary capacity to supply natural gas to the facility. An NUI witness contended that Rockingham had refused to discuss any proposal that would place NUI facilities between its generating plant and the interstate pipeline facilities of Transco and that bypass of NUI would have detrimental effects on North Carolina ratepayers. The Public Staff took the position that bypass of NUI would not serve the public interest and that "a carefully structured agreement between NUI and Rockingham Power could work to the benefit of all North Carolina ratepayers." The Public Staff recommended that Rockingham be granted a certificate conditioned upon its contracting with NUI for the interconnection through which gas for the generating plant would flow. Following the hearing, NUI and Rockingham continued to negotiate and, on June 28, 1999, they filed letters with the Commission reporting that they had reached agreement that no bypass of NUI would occur at the Rockingham facility and that natural gas service to the facility would be provided through NUI. The letters further stated that NUI and Rockingham were continuing to negotiate on the exact rates and terms for service.

On June 30, 1999, the Commission issued an order granting Rockingham a certificate. The order provided that "all natural gas service to the Rockingham facility shall be provided through facilities owned and operated by NUI." The order further provided for NUI and Rockingham to continue their negotiations as to rates and terms of service and to submit the matter to the Commission for resolution if they could not reach an agreement. NUI and Rockingham were not able to agree, and the Commission subsequently heard oral argument and issued a second order on June 23, 2000, determining the terms for service by NUI to the Rockingham facility. The disputed terms had to do with the length of the contract, the demand charge, and the operation and maintenance fee. The June 23 Order decided these disputed terms and required NUI and Rockingham to file an "executed contract for the delivery of natural gas by NUI to Rockingham Power consistent with the rates, terms and conditions found herein to be appropriate."

NUI filed a contract by letter of August 9, 2000. However, the contract had a new "limited pre-granted abandonment authority" provision that had not been discussed during the prior proceedings. By its letter, NUI asked that the Commission approve the agreement and, specifically, the pre-granted abandonment provision. This provision reads as follows:

> In the event that the amount or duration of the Demand Charge or the amount of the O&M Fee is increased other than as a result of the application of Section 4.1 or Section 4.2 of this Agreement, respectively, or Rockingham Power becomes subject to any other or additional fees or charge for the delivery of natural gas to the Project through the NUI Facilities other than as set forth in this Article IV, save and except as the result of increases, fees or charges imposed on a state-wide basis by the North Carolina Utilities Commission, North Carolina state legislature, or other North Carolina governmental or regulatory body on all customers of natural gas distribution companies within the State of North Carolina similarly situated to Rockingham power, (i) this Agreement shall immediately terminate, (ii) NUI shall, for no additional consideration from, or cost to, Rockingham Power other than the payment to NUI by Rockingham Power of any costs for the engineering, procurement or construction of the NUI Facilities that have not been recovered by NUI through the Demand Charges paid by Rockingham Power, immediately assign the NUI Facilities to Rockingham Power, and (iii) NUI shall relinquish any right or entitlement it may have to participate in, or assess any fees or charges with respect to, the delivery of natural gas to the Project. In order to ensure the effectiveness of the foregoing provisions, NUI shall seek to obtain pregranted abandonment authority to transfer the NUI Facilities to Rockingham Power under the circumstances set forth in this Section 4.4.

The Public Staff objected to the pre-granted abandonment provision and undertook negotiations with Rockingham to see if they could come up with mutually agreeable alternative language. After working for several months, they were unable to agree. On July 25, 2001, the Commission issued an order requesting that the parties file comments on the matter.

Rockingham commented that the contract was the product of arm's-length negotiations, that it represents an equitable balance of interests, and that the pre-granted abandonment provision is a major part of the agreement designed to ensure that the parties receive the benefits of the bargain they struck.

The Public Staff commented that the Commission has never pre-granted abandonment authority before and that it would be particularly inappropriate here. In this case, the Commission has already found that bypass is not in the public interest and has conditioned Rockingham's certificate on there being no bypass. The Public Staff also noted that the Commission does not typically approve negotiated contracts. To the extent that Rockingham is concerned about its fees going up, the Public Staff suggested that the Commission could approve those portions of the contract that constitute fees, but not the contract itself or the Commission could simply state that it will not change the contract or impose any additional fees on Rockingham during the contract term.

NUI filed a letter to the effect that it has no comments but "continues to support the relief sought in its initial filing on this matter."

The Commission concludes that the pre-granted abandonment provision is inconsistent with the position that Rockingham took in its June 28, 1999 letter, wherein it agreed that there would be no bypass; that it is inconsistent with the Commission's June 30, 1999 order, which granted a certificate on condition that there be no bypass; and that it is inconsistent with the Commission's June 23, 2000 order, which provided for the parties to file a contract consistent with the terms found appropriate by the Commission. The Commission will not approve the pre-granted abandonment provision as requested by NUI.

IT IS, THEREFORE, SO ORDERED

ISSUED BY ORDER OF THE COMMISSION.
This the 16th day of November, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg111601.01

DOCKET NO. W-354, SUB 236

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Ocean Club Ventures, L.L.C., Complainant v. Carolina Water Service, Inc. of North Carolina, Respondent	)	ORDER SETTING FURTHER HEARING AND REQUIRING PROVISION OF INTERIM SERVICE

BEFORE: Commissioner Sam J. Ervin, IV, presiding; and Commissioners Lorinzo L. Joyner and James Y. Kerr, II

BY COMMISSION: On March 20, 2001, the North Carolina Utilities Commission (Commission) entered an Order Requiring Provision of Service Subject to Conditions (the March 20, 2001, Order) in this proceeding, which arose from a complaint filed by Ocean Club Ventures, L.L.C. (Ocean Club), against Carolina Water Service, Inc. of North Carolina (Carolina Water Service) in which Ocean Club sought the entry of an order requiring Carolina Water Service to provide water and sewer utility service to a tract of real property located in Currituck County, North Carolina, which Ocean Club was attempting to develop known as Corolla Shores. In the March 20, 2001, Order, the Commission found that Ocean Club had standing to maintain the present complaint proceeding; that the Corolla Shores development was contained within Carolina Water Service's Monteray Shores development by virtue of a contiguous extension from Carolina Water Service's Corolla Light service territory; that Monteray Shores, Inc. (Monteray Shores), the developer of the Monteray Shores development, was subject to the Commission's regulatory jurisdiction under the de facto utility doctrine; that the provisions of a contract between Carolina Water Service, Monteray Shores, and Ship's Watch, Inc. (Ship's Watch), the developer of the Buck Island development, which allowed Monteray Shores and Ship's Watch to retain ownership of the water production and wastewater treatment facilities used to serve Carolina Water Service's Monteray Shores service territory were not in the public interest and that these contractual provisions should be modified to unify ownership and control of all of the facilities used to provide water and sewer utility service in the relevant service territory; that service should be extended to the Corolla Shores development under reasonable terms and conditions, including the making by Ocean Club of an appropriate contribution toward the cost of constructing of any necessary wells and sewer treatment facilities needed to serve that area; and that the parties should follow certain procedures in order to implement the Commission's resolution of the matters at issue between the parties. As a result, the Commission ordered that Carolina Water Service and Monteray Shores meet for the purpose of developing a plan for placing the water production and wastewater treatment facilities used to serve Monteray Shores and Buck Island under common ownership and control and file either a proposal for unifying ownership and control of the existing water and sewer facilities as contemplated in the March 20, 2001, Order or a statement of their inability to develop such a plan with the Commission; that Ship's Watch should be requested to voluntarily participate in that process;

that the Commission would enter a further order addressing the manner in which the relevant facilities should be unified and Monteray Shores' continued status as public utility following the completion of that process; that the entity ultimately responsible for serving the Buck Island, Corolla Shores, and Monteray Shores developments should extend water and sewer utility service to Corolla Shores and submit a plan for determining the amount of water production and wastewater treatment capacity needed to provide adequate service in all three developments and the manner in which any additional facilities necessary to provide service to Corolla Shores should be constructed and financed; that any interested party would be allowed an opportunity to be heard with respect to the appropriateness of the proposed expansion plan; that certain motions filed by Ocean Club seeking interim relief were denied as moot; that notice of the Commission's decision should be given to Ship's Watch; and that the Commission would retain jurisdiction over this proceeding to the extent necessary to resolve any issues which might arise during the parties' efforts to comply with this Order.

On April 6, 2001, Ocean Club filed the Renewed Motion of Ocean Club Ventures, L.L.C., for Interim Relief in which Ocean Club renewed its request that water and sewer utility service be immediately provided to Corolla Shores. On April 10, 2001, Monteray Shores and Robert R. DeGabrielle and wife, Laurie T. DeGabrielle (Monteray Shores and the DeGabrielles) filed a Motion by Interveners to Extend Time to File Notice of Appeal and Exceptions to Decision of the Commission and Motion to Deny Complainant's Motion for Interim Relief seeking an extension of time to note an appeal from the March 20, 2001, Order and expressing opposition to Ocean Club's request for interim relief. On April 16, 2001, Carolina Water Service filed a Motion for Extension of Time to Comply with the Commission's March 20, 2001, Order. On April 18, 2001, the Commission entered an Order Granting Motion to Extend Time to File Notice of Appeal and Exceptions which granted the request for an extension of time for Monteray Shores and the DeGabrielles to note an appeal from the March 20, 2001, Order and indicated that Ocean Club's request for interim relief would be addressed at a later time. On the same date, the Commission entered an Order Granting Motion for Extension of Time to Comply with the Commission's March 20, 2001, Order which allowed Carolina Water Service and Monteray Shores until March 21, 2001, to make a filing consistent with Decretal Paragraph 2 of the March 20, 2001, Order. On April 20, 2001, Ocean Club filed Complainant's Response to Intervenor's Motion to Extend Time and Motion to Deny Complainant's Motion for Interim Relief in which Ocean Club took issue with certain statements made by Monteray Shores and the DeGabrielles in seeking to persuade the Commission to reject Ocean Club's request for interim service. On the same date, Ocean Club filed the Response of Ocean Club Ventures to Carolina Water's Motion for Extension of Time in which Ocean Club argued that the important issue before the Commission was its request for interim relief and that Ocean Club was indifferent to the manner in which the issues addressed in Decretal Paragraph 2 of the March 20, 2001, Order were resolved as long as it received service promptly. On April 24, 2001, the Public Staff of the North Carolina Utilities Commission filed the Public Staff Response to Motion by Intervenors to Extend Time to File Notice of Appeal and Exceptions and Motion to Deny Complainant's Motion for Interim Relief in which the Public Staff disputed certain assertions made by Monteray Shores and the DeGabrielles in seeking to persuade the Commission to refrain from granting interim relief.

On April 30, 2001, the Commission entered an Order Requiring Additional Information in which the Commission requested Carolina Water Service, Ocean Club, and Monteray Shores to provide certain specified information concerning the present and projected demand for water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores areas. On May 10, 2001, Ocean Club filed a Response of Ocean Club Ventures, L.L.C., to Commission Order Requesting Additional Information. On May 10, 2001, Carolina Water Service filed the Response of Carolina Water Service, Inc. of North Carolina to April 30, 2001, Order Requesting Information. On May 14, 2001, Monteray Shores and the DeGabrielles filed Interveners' Response to Commission's Order Requesting Additional Information. On the same date, Monteray Shores and the DeGabrielles filed Interveners' Notice of Appeal and Exceptions to the Order of the Commission March 20, 2001, in which Monteray Shores and the DeGabrielles sought review of the March 20, 2001, Order by the North Carolina Court of Appeals.

On May 21, 2001, Carolina Water Service filed the Proposed Solution of Carolina Water Service, Inc. of North Carolina to Lack of Uniform Control to Backbone Water and Wastewater Facilities and Construction of Facilities to Serve Corolla Shores in which Carolina Water Service indicated that the parties had been unable to reach agreement on the most appropriate way to bring the water production and wastewater treatment facilities utilized to serve existing customers under common ownership and control and proposed a solution to that problem for the Commission's consideration. On May 30, 2001, Monteray Shores and the DeGabrielles filed Interveners' Response to Carolina Water Service, Inc.'s Proposal to Comply with the March 20, 2001, Order of the Commission Requiring Provision of Service Subject to Conditions in which they objected to Carolina Water Service's proposed solution, urged that Monteray Shores be made solely responsible for providing water and sewer utility service in Buck Island and Monteray Shores, and argued that Ocean Club should be made responsible for providing any necessary water and sewer utility service in Corolla Shores. On June 15, 2001, Ocean Club filed the Response of Ocean Club Ventures to Proposed Solution of Carolina Water Service, Inc., and Intervenors' Response and Request for Expedited Ruling in which Ocean Club objected to the approaches advocated by both Carolina Water Service and Monteray Shores and the DeGabrielles and reiterated its previous request that the Commission order the immediate interconnection of any facilities in Corolla Shores with those utilized to serve Buck Island and Monteray Shores.

On June 18, 2001, Monteray Shores and the DeGabrielles made an oral motion for extension of time to file and serve a proposed record on appeal. On June 19, 2001, Monteray Shores and the DeGabrielles filed Interveners' Motion Pursuant to N.C. Rules of Appellate Procedure, Rule 27(c)(1) to Extend the Time to File Record on Appeal. The Commission entered an Order Granting Interveners' Motion Pursuant to N.C. Rules of Appellate Procedure, Rule 27(c)(1), to Extend the Time to File Record on Appeal on June 22, 2001. On June 28, 2001, Carolina Water Service filed the Reply of Carolina Water Service, Inc. of North Carolina to the Response of Ocean Club Ventures to Proposed Solution of Carolina Water Service, Inc., in which Carolina Water Service indicated that Ocean Club had previously agreed that the approach embodied in its proposed solution was appropriate and that Carolina Water Service should be made solely responsible for providing water and sewer service in the relevant area. On July 13, 2001, the Commission entered an Errata Order correcting an error in the Order granting Monteray Shores' and the DeGabrielles' request for an extension of time to file and serve a proposed record on appeal. On July 16, 2001, Ocean Club filed a letter setting out its position concerning the settlement negotiations in which it had engaged with Carolina Water Service and arguing that the Commission should not consider the information contained in Carolina Water Service's prior filings concerning this subject in making its decision.

On July 17, 2001, Monteray Shores and the DeGabrielles filed Interveners' Motion Pursuant to G.S. 62-80 and 62-90, in which they requested the Commission to reconsider the March 20, 2001, Order and to set their exceptions to the March 20, 2001, Order for further hearing. On the same date, Monteray Shores and the DeGabrielles requested the North Carolina Court of Appeals to extend the time within which they were entitled to file and serve a proposed record on appeal. On July 20, 2001, the Commission entered an Order Denying Motion for Further Hearing, refusing to either reconsider the March 20, 2001, Order or to set the exceptions submitted by Monterary Shores and the DeGabrielles for further hearing. On the same date, the North Carolina Court of Appeals allowed Monteray Shores and the DeGabrielles until August 17, 2001, to file and serve a proposed record on appeal.

FILINGS BY THE PARTIES

The arguments advanced by the parties in the most important of these filings for addressing the remaining outstanding issues in this proceeding can be summarized as follows:

April 6, 2001 - Renewed Motion of Ocean Club Ventures L.L.C. for Interim Relief.

Ocean Club requested that the Commission order Carolina Water Service, Monteray Shores, and the DeGabrielles to permit the immediate interconnection of the underground water and sewer lines constructed by Ocean Club in Corolla Shores with the existing water and sewer lines being operated by Carolina Water Service and to provide water and sewer utility service to Phase 1 of Corolla Shores at such time as such service was needed. According to Ocean Club, it merely desired to be put in the same position as Currituck County had been placed as a result of the Commission's October 5, 2000, Order in Docket No. W-354, Sub 231. Based upon the Commission's March 20, 2001, Order, Ocean Club was satisfied that the Commission fully intended that it would receive water and sewer service so as to proceed with the reasonable, orderly development of Phase 1 of Corolla Shores. Carolina Water Service, Monteray Shores and the DeGabrielles should be ordered to permit the requested interconnection of underground water and sewer utility lines because Ocean Club had begun paving the streets that will serve Phase 1 as part of its development activities. The "natural" point of interconnection between the underground water and sewer lines constructed by Ocean Club and the adjacent underground water and sewer lines being operated by Carolina Water Service in Monteray Shores was located at a place where paving would be required. Since Ocean Club desired to avoid the necessity for digging up the pavement, once laid, in order to make the interconnection and then having to incur the cost of repaving the same area, it had approached Carolina Water Service with a proposition that, if Carolina Water Service would consent to the necessary interconnection of the underground water and sewer lines being made, Ocean Club would "lock" or "cap" the interconnection, allowing Carolina Water Service to have complete control over the interconnection and enabling Carolina Water Service to ensure that there were no flows, in either direction, between Monteray Shores and Corolla Shores without the knowledge and consent of Carolina Water Service. Carolina Water Service had agreed to this proposal and was about to effectuate it when Monteray Shores and the DeGabrielles filed a lawsuit blocking the interconnection. In addition, Ocean Club alleged that Monteray Shores and the DeGabrielles had taken other actions which were intended to prevent the interconnection of the Monteray Shores and Corolla Shores systems, such as accelerating certain development activities and seeking revision of the Monteray Shores wastewater discharge permit to reduce the approved capacity of the existing facility. As a result, Ocean Club requested the Commission to order Carolina Water Service, Monteray Shores and the DeGabrielles to provide water and sewer service to Phase 1 of Corolla Shores, even if such service is required prior to the ultimate determination of cost responsibility for any additional "backbone" facilities that may be needed to serve the relevant area.

April 10, 2001 - Monteray Shores Motion to Deny Complainant's Motion for Interim Relief.

According to Monteray Shores and the DeGabrielles, the Temporary Restraining Order prohibiting the interconnection of water and sewer facilities in Monteray Shores and Corolla Shores remained in full force and effect. In addition, Monteray Shores and the DeGabrielles claimed that the March 20, 2001, Order contained clear errors of law. Any attempt to implement the remedy set out in the March 20, 2001, Order pending appeal could have long lasting and potentially devastating consequences. Monteray Shores and the DeGabrielles indicated that they were scheduled to meet with Carolina Water Service for the purpose of discussing the implementation of the March 20, 2001, Order. Monteray Shores and the DeGabrielles denied Ocean Club's allegation that they had engaged in certain development activities for the purpose of preventing Ocean Club from obtaining water and sewer utility service and claimed that numerous other statements in the request for interim service were inaccurate.

April 20, 2001 - Complainant's Response to Intervenors' Motion to Deny Complainant's Motion for Interim Relief.

Ocean Club argued that Monteray Shores and the DeGabrielles were attempting to divert the Commission's attention from the time-sensitive issues raised by its motion for interim service to Phase 1 of Corolla Shores. Although Ocean Club remained willing to pay a fair and reasonable portion of the cost of extending water and sewer utility service to Corolla Shores, it should not have to wait an extended period of time to receive the service authorized in the March 20, 2001, Order. Once again, Ocean Club argued that it should be put in the same position as Currituck County, which had been provided with interim service to the restrooms at the Whalehead Club after the hearing held in Docket No. W-354, Sub 231. According to Ocean Club, the temporary injunctive relief prohibiting the interconnection of water and sewer facilities in Corolla Shores with those in Monteray Shores had not been properly extended, so that the original Temporary Restraining Order was no longer in effect. As a result of the fact that additional proceedings could delay implementation of the remedy contemplated by the March 20, 2001, Order when the only real issue which remained to be decided was the amount which Ocean Club should be required to pay to obtain expansion of any needed "backbone" facilities, Ocean Club urged the Commission to uphold the intent of the March 20, 2001, Order by requiring the immediate extension of water and sewer service to Phase 1 of Corolla Shores.

May 10, 2001 - Ocean Club Ventures L.L.C.'s Response to Commission Order Requesting Additional Information.

Pursuant to the Commission's April 30, 2001, Order Seeking Additional Information relating to present and projected demand for water and sewer service, Ocean Club submitted information which was developed by its consulting engineers. That information assumed a physical interconnection of the facilities in Corolla Shores and Monteray Shores and the receipt of service at the 19 residential lots contained in Phase 1 of Corolla Shores. The current demand upon the water production and wastewater treatment facilities in Corolla Shores is 11,400 gallons per day. The projected demand upon the water production and wastewater treatment facilities in Corolla Shores twelve months from now is 27,400 gallons per day. Water demand was assumed to equal wastewater demand. Wastewater demand was calculated in accordance with 15A NCAC 2H.0219(l)(1), which assumes that a residential unit would require 120 gallons per day per bedroom. In making its calculation, Ocean Club assumed an average of five bedrooms per residence. The increase from the estimate for the present time to the estimate for the next twelve months stemmed from the assumption that an additional 16,000 gallons per day commercial load would be added during that time period because of the opening of a 40,000 square foot food store plus general retail and food service businesses and the use of the design requirements specified in 15A NCAC 2H.0219(l)(1).

OCV argues that it continued to be harmed by the delay in obtaining water and sewer utility service for obvious business reasons and that, even if connection were ordered immediately, it would be months before a Certificate of Occupancy could be granted to a fully constructed premise (residential or commercial) in Corolla Shores. During this interval, additional water and wastewater facilities could be constructed, if required.

May 10, 2001 - Response of Carolina Water Service Inc. of North Carolina to April 30, 2001, Order Requesting Additional Information.

Carolina Water Service reported that existing wells in service in Monteray Shores produce 250 gallons per minute or 180,000 gallons per day. Two of the wells are indefinitely out-of-service due to high chloride levels. The most recent available peak demand information calculated using actual average demands for the highest two days of record in accordance with Division of Environmental Health regulations indicated an average demand for July 28-29, 2000, of 213,000 gallons per day. The projected demand twelve months in the future was estimated to be 238,000 gallons per day based on actual construction underway and previous year's growth.

The current capacity of the wastewater treatment facilities in Monteray Shores is 180,000 gallons per day. The average actual daily flow in July of last year, which is typically when the highest demand occurs in Monteray Shores, was 119,000 gallons per day on average. The actual peak daily flow during this time was 158,000 gallons per day. The projected demand on the wastewater treatment facilities twelve months in the future was estimated to be 140,000 gallons per day, with a peak flow of 172,000 gallons per day. These estimates were based on actual construction underway and previous growth data.

May 14, 2001 - Interveners' Response to Commission's Order Requesting Additional Information.

According to Monteray Shores and the DeGabrielles, the current capacity of the water production facilities in Monteray Shores is 274,320 gallons per day. Based on actual usage for 2000 and new construction for 2001, the anticipated demand for 2001 in Monteray Shores and Buck

Island is 234,400 gallons per day or 85% of the available capacity. Monteray Shores and the DeGabrielles contend that the projected demand upon the water production facilities in Monteray Shores and Buck Island in twelve months will exceed current capacity; for that reason, Monteray Shores and the DeGabrielles are constructing a water storage facility for completion during 2001. This estimated demand is based upon 13 years of history in this development in particular and the Outer Banks in general.

The current capacity of the wastewater treatment facilities at Monteray Shores is 180,000 gallons per day. The current demand for wastewater service in Monteray Shores and Buck Island is 150,000 gallons per day in season. This figure is based on actual usage for the peak period in 2000 and projections for 2001 based on construction. In twelve months, Monteray Shores and the DeGabrielles estimate that demand for sewer service will be in excess of 80% of peak capacity, with this estimate based on actual usage plus construction underway.

May 21, 2001 - Proposed Solution of Carolina Water Service, Inc. of North Carolina to Lack of Uniform Control to Backbone Water and Wastewater Facilities and Construction of Facilities to Serve Corolla Shores.

Carolina Water addresses two issues raised in the March 20, 2001, Order: the existing problem created by the contract between Carolina Water Service, Monteray Shores, and Ship's Watch that did not clearly authorize unified control over "backbone" water and wastewater facilities used to serve the Monteray Shores development, and the construction or expansion of facilities to serve end-users within Corolla Shores. CWS' proposal addresses both of these issues in the same filing to expedite a final decision.

The contract between Carolina Water Service and the developers reserved ownership of the central water supply and treatment system so that the developers could sell or donate the "backbone" facilities if bulk water supply and sewage treatment facilities became available in the future. The developers also retained ownership of the land on which the existing "backbone" facilities were situated. The developers leased the land on which the facilities were located to Carolina Water Service and made the "backbone" facilities and subsequent expansions available for use by Carolina Water Service in providing water and sewer utility service until the execution of an alternate agreement for the provision of such service. The Commission found in the March 20, 2001, Order that the lack of uniform control over these "backbone" facilities is inconsistent with the public interest and that the parties should develop a proposal for rectifying this deficiency.

According to Carolina Water Service, the parties have met in accordance with the Commission's instructions, no mutually satisfactory solution has been identified. Monteray Shores views its ownership rights as having substantial value, entitling it to substantial compensation. Carolina Water Service is unwilling to convey its rights to Monteray Shores because Carolina Water Service needs them to fulfill its public utility responsibilities. The fundamental problem here is not that Monteray Shores has retained ownership of the "backbone" facilities, but rather that Carolina Water Service neither owns nor controls land which can be used to provide service within Corolla Shores. Carolina Water Service does not believe that the Commission must completely overhaul the contractual arrangement between the parties to resolve this issue since the existing contract can be interpreted to give Carolina Water Service the necessary control over the "backbone" facilities. In other words, the Commission should interpret the contract to mean that Monteray Shores has no right to prevent Carolina Water Service from serving Corolla Shores in accordance with the March 20, 2001, Order. This implementation permits service to be provided to Ocean Club while foreclosing Monteray Shores' claims of unlawful contract interference and uncompensated taking of property thus reducing the vulnerability of the March 20, 2001, Order on appeal.

The adoption of this approach does not, in Carolina Water Services's view, solve the problem stemming from the fact that Carolina Water Service does not own or control land on which to construct expanded facilities. In order to solve this problem, the Commission should rule that Monteray Shores and Ship's Watch have leased the existing facilities, expansion rights therein, and the underlying land in such a manner that Carolina Water Service is able to serve Corolla Shores. This interpretation would not require Carolina Water Service to provide additional lease payments to the landowners and would provide Carolina Water Service with the right to use the facilities as long as it continues to carry out its public service obligations.

Carolina Water Service contends that this approach would serve the public interest. Were Carolina Water Service to lose Monteray Shores, upward pressure would be placed on the rates paid by the remaining ratepayers. Carolina Water Service, unlike Monteray Shores, has no competitive development objectives that would interfere with the fulfillment of the objectives of the March 20, 2001, Order.

Carolina Water Service states with respect to the second issue addressed in this filing that insufficient capacity exists in the water and sewer facilities currently available to serve end-users in Monteray Shores. Expansion of the existing facilities is inevitable. Land in this area is very expensive. For that reason, there should be a conversion to sewer reuse to reduce the amount of land needed for effluent disposal and to protect the environment. Monteray Shores refuses to allow the use of its land for the necessary additional facilities. As a result, Monteray Shores should construct the additional facilities required to serve its needs and Ocean Club should construct the facilities it needs on property located within Corolla Shores. The existing agreement requires Monteray Shores to construct any expansion needed to serve that development. Ocean Club has agreed to construct capacity to serve its anticipated needs within Corolla Shores so long as the facilities constructed there are connected to the Monteray Shores system. Although expanding the existing facilities would be the most cost effective alternative, Carolina Water Service is powerless to dictate that result. Since Ocean Club is amenable to either expanding the existing facilities to meet the combined needs of both Monteray Shores and Ocean Club or constructing additional facilities within Corolla Shores, Carolina Water Service has developed the recommendation which it now advances. In any event, the distribution and collection facilities within Monteray Shores and Corolla Shores should be interconnected. Under this proposal, Monteray Shores should add at least 180,000 gallons per day to both the water and sewer facilities in accordance with the existing contract and the facilities within Corolla Shores should have approximately 100,000 gallons per day of capacity.

May 30, 2001 - Interveners' Response to Carolina Water Service, Inc.'s Proposal to Comply with the March 20, 2001, Order of the Commission Requiring Provision of Service Subject to Conditions.

WATER AND SEWER - COMPLAINT

Monteray Shores and the DeGabrielles purchased a 350 acre tract in Currituck County in the mid 1980's. The development which Monteray Shores planned for this tract was to be a Planned Unit Development, which meant that the tract had to remain under single ownership or control. Monteray Shores designed, built, permitted and operated a water and wastewater system with its own funds and search for a suitable utility to operate the system. The State encouraged this approach to keep the developer from taking the profits from the development and leaving the customers holding the bag on a substandard or defective system.

Monteray Shores was reluctant to simply give the system away. As a result, Monteray Shores entered into a bifurcated contract with Carolina Water Service which gave Monteray Shores ownership and control consistent with its investment and lowered Carolina Water Service's tax liability. A material aspect of this agreement was that Carolina Water Service would obtain a franchise for the system; however, Carolina Water Service did not do so. Instead, Carolina Water Service elected to operate the system as a contiguous extension from its Corolla Light service territory because it was in its economic interest to do so. As a result, Monteray Shores and the DeGabrielles assert that they have found themselves embroiled in litigation before the Commission in which a land speculator seeks to have the Commission make a <u>de</u> <u>facto</u> ruling addressing application of the Currituck County land use ordinance.

In the early 1990's, Monteray Shores and the DeGabrielles allowed Phase III of the development to revert to the original owners. Ocean Club purchased part of Phase III and has an option on the remainder for allegedly speculative purposes. Monteray Shores and the DeGabrielles continue to develop Phases I and II and have an investment in commercial property and about 40 residential lots. Monteray Shores and the DeGabrielles contend that Ocean Club is principally interested in obtaining the right to tie into the Monteray Shores system, thereby obtaining an "enormous windfall profit."

Monteray Shores and the DeGabrielles have constructed a "state of the art" system which has functioned well for 13 years. Monteray Shores and the DeGabrielles consented to an interconnection with a neighboring system which experienced water supply problems, after which Carolina Water Service pumped water for the benefit of the neighboring system for almost 24 hours a day in violation of state law, rendering two of the Monteray Shores wells unusable. The corporate parent of Carolina Water Service is in the process of being sold to a foreign utility, a development which would effectively mean that Monteray Shores and the DeGabrielles would have invested a large amount of money into a system which Carolina Water Service would be able to sell at a profit.

Ocean Club is merely a land speculator. Monteray Shores and the DeGabrielles contend that Ocean Club's capacity figures are based on minimum averages, inaccurately assume that water and sewer and sewer flow will be identical, and overlook the fact that people wash their cars, fill their swimming pools or hot tubs, and take outside showers after coming in from the beach.

Moreover, despite its claims that time is of the essence, Ocean Club knew that there were problems and has continued to try to force a Commission solution rather than allow the marketplace to work. The real importance of Ocean Club's desire for immediate interconnection is to enable it to make a windfall profit, not to make the system more efficient.

Monteray Shores and the DeGabrielles contend that Carolina Water Service has mismanaged the system, having violated its contract with Monteray Shores and ruined two wells by overuse. Carolina Water Service wants to add Ocean Club to its "stable" to increase the profit from the impending sale even further. Carolina Water Service's proposed solution would allow Ocean Club to obtain the right to use the system for nothing despite the fact that Monteray Shores and the DeGabrielles built the system 13 years ago at a cost of $2,000,000.00. Ocean Club would reap an enormous windfall and gain a competitive advantage from interconnecting with Monteray Shores, which means that the constitutional issues which Monteray Shores and the DeGabrielles have raised are still present.

Carolina Water Service has acknowledged that Monteray Shores and the DeGabrielles have done much for Currituck County, describing Monteray Shores as a development which others would do well to emulate. Monteray Shores and the DeGabrielles have worked hard to make the development a success and have a sizable investment in commercial property, apartments, single family residences, and building lots. It is in the long term best interest of Monteray Shores and the DeGabrielles to continue their development efforts and operate the utility themselves. Monteray Shores and the DeGabrielles engineered, built and paid for the facilities which operate so well; Carolina Water Service has done nothing other than "burn out" two wells. Ocean Club's capacity figures are a "fabrication," making it obvious that it is the type of "developer" responsible for the perception that only entities like Carolina Water Service should operate the system.

The $2,000,000.00 that Monteray Shores and the DeGabrielles invested in the design and construction of the system in 1988 are the equivalent of more than $5,000,000.00 today. The existing system is designed to serve Monteray Shores Phases I and II and Buck Island at full build-out. Monteray Shores and the DeGabrielles have made the investment necessary to ensure this result and are prepared to do so in the future. Monteray Shores and the DeGabrielles have planned for the expansion of the existing system to achieve this result. Monteray Shores and the DeGabrielles are also prepared to expand the system to a full reuse quality system that would serve Ocean Club's real needs. Achieving this result involves an "elegant" engineering solution that is beyond the capability of Carolina Water Service. Carolina Water Service has no investment in the system, which deprives it of any incentive to be innovative; in fact, Carolina Water Service is discouraged from innovation because it has no investment in the system. Monteray Shores and the DeGabrielles have every incentive to innovate and maximize the use of the land and facilities and are ready to compensate Carolina Water Service for its investment in the system.

As a result, Monteray Shores and the DeGabrielles contend that the public interest, which they equate with the interests of the existing and future customers in Monteray Shores and Buck Island, would be best served if they received full control over the water and wastewater treatment facilities. Monteray Shores and the DeGabrielles would be willing to operate a system in Corolla Shores if Ocean Club furnished sufficient land and capital. However, Monteray Shores and the DeGabrielles would not allow Ocean Club to interconnect with the Monteray Shores facility since its plans are mercurial, since the best interests of existing customers would not necessarily be served by such an interconnection, and since a decision to that effect would have implications under the Currituck County land use ordinance which should be determined in the General Court of Justice or the marketplace rather than by the Commission. Ocean Club would also have the option of operating independently or interconnecting with the Corolla Light system.

WATER AND SEWER - COMPLAINT

June 15, 2001 - Response of Ocean Club Ventures to Proposed Solution of Carolina Water Service, Inc. and Interveners' Response and Request Expedited Hearing.

Ocean Club addressed in this filing both the proposed solution submitted by Carolina Water Service and the claim by Monteray Shores and the DeGabrielles that the water production and wastewater treatment facilities currently utilized to serve Monteray Shores should be unified by vesting total control over those facilities in Monteray Shores.

With respect to Carolina Water Service's proposed solution, a number of factors establish that Carolina Water Service should retain the right to serve Monteray Shores, Buck Island, and Corolla Shores with consolidated operational control over the facilities needed to provide water and sewer utility service in those areas. In the absence of an agreement between Carolina Water Service and Monteray Shores to that effect, the Commission should grant control over these facilities to Carolina Water Service.

First, Carolina Water Service's Corolla Light service territory was expanded by contiguous extension to encompass the entire Monteray Shores development, including the area now known as Corolla Shores. As a result, Carolina Water Service is required to provide reasonably adequate service within its service territory and to extend service to additional customers in that territory upon reasonable terms and conditions. According to North Carolina law, Carolina Water Service has the exclusive right to serve Corolla Shores absent a showing that it is not rendering adequate service or that it cannot or will not render such service. As a result of the fact that Carolina Water Service indicates that it is willing and able to provide such service, North Carolina law strongly suggests that Carolina Water Service should continue to provide service in Monteray Shores and Buck Island and should be designated to provide service in Corolla Shores.

Second, what is now Corolla Shores was originally part of Monteray Shores, with water and sewer service to be provided there using the "backbone" facilities at issue in this proceeding. Under the operating agreement and lease between Carolina Water Service, Monteray Shores, and Ship's Watch, operational control over these facilities was transferred to Carolina Water Service for a term of 99 years. As a result of the extension of its service territory from Corolla Light to Monteray Shores and Buck Island, Carolina Water Service is currently providing water and sewer service to all portions of this service territory except Corolla Shores, which is sandwiched in between currently served areas. These facts favor consolidation of the "backbone" facilities necessary to serve all of these areas under the control of Carolina Water Service.

Third, Carolina Water Service cites economies of scale associated with providing service to contiguous areas as a reason to consolidate the "backbone" facilities under its control. According to Carolina Water Service, these economies of scale will benefit Carolina Water Service and its ratepayers by reducing the costs associated with providing water and sewer service in this area of the Outer Banks. Carolina Water Service's logic is compelling and supports consolidating the "backbone" facilities under Carolina Water Service's control.

Fourth, Carolina Water Service has provided adequate water and sewer service to the Monteray Shores and Buck Island developments for over 12 years. Moreover, Carolina Water Service has provided water and sewer service in contiguous developments for even longer. This history of successfully operating water and sewer facilities in this area provides substantial evidence of Carolina Water Service's ability to provide reliable and adequate service in the future. Monteray Shores has no corresponding experience.

Fifth, Carolina Water Service has provided water and sewer service to a broad range of communities and developments in North Carolina. Carolina Water Service is focused upon and experienced in the provision of utility service. Carolina Water Service's economic well-being is directly derived from the quality of its utility service. Monteray Shores, on the other hand, directly competes with Ocean Club in the real estate development business. As a result, the public interest requires that the "backbone" facilities presently serving Monteray Shores and Buck Island be consolidated under the full control of Carolina Water Service.

The Commission has previously concluded that service should be provided to Corolla Shores on reasonable terms consistent with the Commission's normal rules for extending water and sewer service and that the existing "backbone" facilities must be expanded in the near future in order to provide continuing service to Monteray Shores and Buck Island. In the March 20, 2001, Order, the Commission directed Carolina Water Service (or whatever entity became responsible for providing service to Monteray Shores and Buck Island) to prepare a detailed plan setting out the most efficient way to provide expanded water and sewage treatment capacity sufficient to meet the needs of all affected areas at full buildout without subsidization of any party. The Commission provided for service of this plan on all interested parties with the opportunity for review and comment prior to a final Commission decision. The proposed solution submitted by Carolina Water Service subverts the process established by the Commission and had more to do with avoiding controversy (and potential litigation) with Monteray Shores than with providing for the efficient expansion of utility service necessary to serve Corolla Shores. Moreover, Carolina Water Service's proposal is not supported by any detailed plan and would subvert the Commission's service extension rules.

Although Decretal Paragraph 6 of the March 20, 2001, Order provided for the prompt development of a detailed, logical, and comprehensive plan for the provision of service to Corolla Shores at a reasonable expense and in the most efficient manner possible, Carolina Water Service's proposed solution results in an immediate decision to construct additional facilities on property provided by Ocean Club. Aside from the fact that Carolina Water Service's proposal involves more than a plan for unifying control over the water production and wastewater treatment facilities, which is all that the March 20, 2001, Order contemplated at this time, it lacks detailed engineering or financial analysis and is directly contrary to Carolina Water Service's stated preference for expanding the existing plant as the most efficient alternative. In other words, while Carolina Water Service's proposal would provide a form of relief to Ocean Club, this proposal is premature, conflicts with Carolina Water Service's own analysis of the most efficient way to provide service in the affected areas, and has more to do with a desire to avoid conflict with Monteray Shores than with the efficient provision of utility service. As a result, the Commission should reject Carolina Water Service's proposal that the needed facilities be constructed on Ocean Club's property and proceed to resolve the remaining issues in accordance with the procedures outlined in the March 20, 2001, Order.

Ocean Club further asserts that much of the response filed by Monteray Shores and the DeGabrielles to Carolina Water Service's proposed solution consists of unsubstantiated, conclusory allegations and an attack upon the motives and character of Carolina Water Service and Ocean Club.

At bottom, Ocean Club believes that Monteray Shores and the DeGabrielles contend that there is no urgency in providing service to Corolla Shores and that unified control over the "backbone" facilities should be given to Monteray Shores. Despite the insistence of Monteray Shores and the DeGabrielles upon their rights in the facilities needed to provide such service, the Commission has ruled that the extension of service to Corolla Shores is appropriate and established a procedure intended to result in the provision of such service. During the year when water and sewer service has been unavailable to Corolla Shores, Monteray Shores has vigorously pursued additional property development while Ocean Club has been unable to move forward with the development of Corolla Shores. The increased administrative and carrying costs which Ocean Club has incurred during this period have served no purpose other than to increase the cost which purchasers of lots in Corolla Shores will be required to pay. It is not in the public interest for Ocean Club to be compelled to incur these costs longer than necessary.

Although Monteray Shores claims that Carolina Water Service has mismanaged and overused the "backbone" facilities, that it seeks unified control over the system for the purpose of selling the system to a third party, that Carolina Water Service's attempt to obtain control over the system raises significant constitutional issues, that the successful operation of the "backbone" facilities resulted from its own design and construction activities, and that the"elegant" engineering solution which must be adopted to resolve the issues which are before the Commission at this time is beyond the capabilities of Carolina Water Service, Monteray Shores has provided no evidence that substantiates these contentions. Most significantly, Monteray Shores provides no evidence that it has ever operated a water or sewer system or has any idea how to do so, depriving the Commission of any justification for concluding that the "backbone" facilities should be unified under Monteray Shores' control. On the other hand, Monteray Shores did admit that service to Corolla Shores could be provided through expansion of the existing "backbone" facilities into a full reuse quality system. If Monteray Shores has plans which would permit such a result, it should be required to disclose them in order to permit an evaluation of the feasibility of expanding the existing facilities to serve Corolla Shores and the validity of Monteray Shores' claim to possess the technical expertise to supervise the expansion of the "backbone" facilities.

At this point, the Commission must decide to whom it will grant consolidated control over the "backbone" facilities and how and when service will be extended to Corolla Shores. Ocean Club claims that identifying the party which should control the "backbone" facilities should be simple given the present record. The Commission has already established a procedure for determining how service should be extended to Corolla Shores and should continue to follow that procedure. As a result, the only remaining issue is when service should be extended to Corolla Shores.

The Commission has already determined that the extension of service to Corolla Shores on reasonable terms and conditions is in the public interest. Ocean Club understands its obligation to provide a reasonable contribution to fund the additional capacity necessary to serve Corolla Shores. Thus, only remaining issue is the practical implementation of these earlier decisions.

Although Ocean Club agrees with the Commission's expressions of concern over the possible impact of the construction of Corolla Shores on the ability of the existing facilities to serve Monteray Shores and Buck Island at full buildout, the same concern should be displayed for other customers and potential customers of Carolina Water Service, including Ocean Club. Although the harm that may arise from the use of the existing "backbone" facilities to provide service in Corolla Shores is only a potential harm that may occur at some indeterminate future time, the substantial harm that Ocean Club has suffered, is currently suffering, and will continue to suffer due to the absence of water and sewer utility service cannot be described in the same manner. While Ocean Club has been substantially vindicated in its principal beliefs about its right to obtain water and sewer service from Carolina Water Service on reasonable terms, no relief has yet materialized due to the complicated issues of law and fact that had to be resolved first. Enough of those issues have been resolved to permit an award of interim relief in order to mitigate the continuing harm that Ocean Club is suffering. An award of interim relief is an appropriate means to provide fair and equal treatment to all parties to this proceeding.

Ocean Club's development activities are currently at a standstill due to its inability to demonstrate to Currituck County officials with some reasonable degree of certainty that water and sewer service will ultimately be available for Phases I and II of Corolla Shores. A myriad of permitting, inspection, and construction activities will be required before any demand for water or sewer service will arise from Corolla Shores. These activities could not be completed before March, 2002, even if these activities commenced tomorrow. As a result, while it is not critical that Ocean Club be provided with immediate service, it is critical that it be provided with the immediate right to interconnect. Ocean Club has installed water and sewer mains up to a planned interconnect point with the system serving Monteray Shores and Buck Island. Although actual interconnection did not occur because Carolina Water Service honored Monteray Shores' objection to that process, the physical act of interconnecting the two systems would be an uncomplicated and straightforward proposition that can be accomplished expeditiously once authorization is granted.

Ocean Club urged the Commission to permit an immediate interconnection with the existing Carolina Water Service facilities and to order Carolina Water Service to provide interim service to Phases I and II of Corolla Shores, subject to its ability to provide such service without jeopardizing service to other customers. According to Ocean Club, this proposal is just and reasonable because there is an existing level of surplus capacity; because the existing "backbone" facilities will need to be expanded in the near future, resulting in substantial excess capacity; because consolidating operational control over the "backbone" facilities in the hands of Carolina Water Service combined with Carolina Water Service's control over other facilities serving contiguous developments will increase the likelihood that it will be able to meet customer needs in all relevant developments, including Corolla Shores, in the near term; because Carolina Water Service will protect the interests of other affected customers; and because providing immediate service to Corolla Shores will maximize the opportunity for the interests of all parties to be served with no risk to any party other than Ocean Club. Ocean Club has struggled to ensure that its proposal does not violate the principles laid out in the March 20, 2001, Order in developing this proposal and has, by doing so, placed itself at a disadvantage compared to every other customer of Carolina Water Service on the Outer Banks. Even so, Ocean Club requested the Commission to accept this proposal by exercising its clear authority to modify or amend the existing contracts between Carolina Water Service and Monteray Shores to the extent necessary to serve the public interest. Ocean Club also requested the Commission to rule on the pending issues at the earliest possible time and to rule on its request for interim service within the next 30 days.

June 28, 2001 - Reply of Carolina Water Service, Inc. of North Carolina to the Response of Ocean Club Ventures to Proposed Solution of Carolina Water Service, Inc.

Carolina Water Service proposed to remedy the lack of uniform control over the backbone water and wastewater facilities and to construct the additional facilities needed to serve Corolla Shores by giving control of the water and wastewater facilities used to provide service within Monteray Shores to Carolina Water Service and to serve Corolla Shores through water and wastewater facilities to be constructed on property owned by Ocean Club and interconnected with existing Monteray Shores facilities. Carolina Water Service expressed surprise that Ocean Club objected to this proposal because Ocean Club agreed to this proposal before Carolina Water Service presented it to the Commission. During earlier discussions between Carolina Water Service and Ocean Club, Ocean Club proposed a number of solutions, one of which was the construction of capacity needed to serve Corolla Shores on Ocean Club property. After preparing a draft pleading which became the filing in which Carolina Water Service advanced its proposed solution to the problems addressed in the March 20, 2001, Order, Carolina Water Service presented this document to Ocean Club and the document was modified in a number of minor ways at Ocean Club's request. Carolina Water Service believed that it had Ocean Club's assent when it presented its proposal to the Commission.

Carolina Water Service reiterated that it has no property within Monteray Shores upon which to expand facilities to serve Ocean Club. As a result, Carolina Water Service refers the existing dispute between itself and Ocean Club to the Commission for resolution. Carolina Water Service has done its best to comply with the directives in the March 20, 2001, Order. Carolina Water Service is powerless to assist the Commission if parties are free to change their positions at will.

July 16, 2001 - Letter Dated July 14, 2001, from James H. Jeffries, Attorney for Ocean Club.

Ocean Club argues that no conclusive settlement was reached between itself and Carolina Water Service. Ocean Club's various settlement offers were conditioned, among other things, upon the agreement of all interested parties, including Monteray Shores, and the submission of a settlement agreement to the Commission within a specified time frame. Monteray Shores never assented to the proposal and no settlement agreement was ever submitted to the Commission. As a result, this matter has not been settled, which leaves all parties free to pursue the merits of their respective positions.

Although Ocean Club recognizes that the "build facilities on Ocean Club property" approach advocated by Carolina Water Service is one possible solution, Ocean Club does not believe that it is the best option. Jumping immediately to such a solution is also contrary to the March 20, 2001, Order, which directs Carolina Water Service to study and provide the Commission with a detailed analysis of the best way to provide service to Corolla Shores. Ocean Club has not waived any right to present its position on how best to serve Corolla Shores.

DISCUSSION AND CONCLUSIONS

A. UNIFICATION OF CONTROL OVER UTILITY FACILITIES

The only apparent area of agreement between the parties appears to be that the meetings between Carolina Water Service and Monteray Shores required under the March 20, 2001, Order failed to produce an agreed-upon plan for bringing the facilities used to provide water and sewer utility service in the Buck Island and Monteray Shores developments under common ownership and control. As the Commission has already noted, Carolina Water Service has submitted a proposal under which it would operate as the certified utility for the relevant area and obtain control over the existing water production and wastewater treatment facilities on the basis of its existing contractual rights over the wells and sewage treatment facilities owned by Monteray Shores and Ship's Watch. Ocean Club supports this aspect of Carolina Water Service's proposal. Monteray Shores, on the other hand, contends that Carolina Water Service should be stripped of its existing franchise and that Monteray Shores should be declared the sole certificated water and sewer utility in the area. The record does not describe the extent of Ship's Watch's participation in the discussions required by the March 20, 2001, Order or the extent to which Ship's Watch wishes to be heard with respect to its status as a de facto utility. As a result, the Commission has no choice except to schedule a further evidentiary hearing which is intended (1) to provide Ship's Watch with an opportunity to be heard with respect to both the Commission's conclusion in the March 20, 2001, Order that Ship's Watch appeared to be a public utility as defined in G.S. 62-3(23)a.2, and the manner in which its interests and the interests of the residents of Buck Island should be protected and (2) to provide the basis for the entry of an order determining the identity of the entity which should ultimately be responsible for the provision of water and sewer utility service and the manner in which the existing water production and sewage treatment facilities in the relevant area should be brought under common ownership and control. As a result, the Commission concludes that a further evidentiary hearing should be scheduled in this proceeding to address these issues, which must be resolved in order to implement the remedial plan outlined in the March 20, 2001, Order.

Although the Commission understands that Carolina Water Service and Ocean Club would prefer that this issue be resolved on the basis of the existing record, the Commission does not believe that acting in that manner would be appropriate. First, the resolution of this issue appears to involve issues of fact which are not appropriately decided on the basis of the present record. Secondly, the resolution of this issue necessarily involves the potential modification of a contract to which Ship's Watch is a party. Given that Ship's Watch has not been heard with respect to a number of issues, including its status as a de facto utility and its views concerning the problems arising from the absence of unified control over the existing water production and wastewater treatment facilities, the Commission concludes that Ship's Watch must be given an opportunity to present evidence with respect to these issues. As a result, the Commission rejects the suggestion advanced by Carolina Water Service and Ocean Club that this issue be decided on the basis of the existing record.

At least one other matter should be addressed in connection with the additional hearing which the Commission has scheduled in this proceeding. The record developed in this proceeding to date suggests the existence of a considerable degree of rancor between the parties, much of which appears to stem from considerations relating to competitive conditions in the real estate business on the Outer Banks. Although the Commission is, of course, concerned about the relative equities present in each case, we are not charged with the responsibility for regulating competitive conditions in the real estate market. Instead, our principal responsibility is to ensure that utility service is provided to end users in a reliable and efficient manner and at a reasonable price. As a result, the ultimate issue which the Commission will address at the additional hearing which we have decided to schedule in this proceeding is determining the most efficient manner in which water and sewer utility service can be provided to the end-user customers located in the developments under consideration. The factors upon which the Commission will focus at the additional hearing include identifying the entity which is best qualified to operate the water and sewer facilities in the area in a competent and efficient manner and determining the most efficient way, from a technical operations point of view, to unify control over the facilities used to provide water and sewer service in that area. The Commission urges all parties to structure their presentations to the Commission with this end in mind and to refrain from disputes over extraneous issues. The Commission will not hesitate to take appropriate action in the event that any party fails to heed this admonition.

B. **REQUEST FOR INTERIM SERVICE**

The second issue which must be resolved at the present time is the extent to which we should order the provision of interim service to Corolla Shores, including the right to interconnect with the existing water and sewer facilities used to serve the Monteray Shores and Buck Island developments. Although the Commission ordered the provision of service to Corolla Shores in the March 20, 2001, Order, it refrained from providing Ocean Club with immediate relief on mootness grounds for two different reasons. First, the Commission had serious concerns about the adequacy of the existing facilities to serve the present and anticipated demands for water and sewer service in all three developments. Put another way, the Commission was concerned that the allowance of Ocean Club's request for immediate relief would create an unacceptable risk that the water and sewer utility service provided in the Buck Island, Corolla Shores, and Monteray Shores areas would be inadequate in the event that additional loads were added to the system, particularly given the uncertainty of the capacity evidence contained in the existing record. Secondly, the Commission felt that the procedures outlined in the March 20, 2001, Order, which contemplated a two-stage process under which the issues arising from the divided ownership of the existing water and sewer utility facilities would be resolved first, after which a plan for extending service in an orderly and efficient manner to Corolla Shores would be developed and implemented. Although the Commission did, of course, recognize that there was a risk that the parties would be unable to successfully implement this remedy without additional Commission intervention, we hoped that the parties would implement the stated intent of the March 20, 2001, Order with reasonable expedition and without the necessity for our assistance. Unfortunately, as has been noted above, these hopes have been dashed. Given that water and sewer utility service is unlikely to be extended to the Corolla Shores area in the near future without additional Commission action and that the Commission had not intended that the process of extending service to Corolla Shores be delayed any longer than necessary to implement the plan outlined in the March 20, 2001, Order, the Commission will revisit the merits of Ocean Club's request for the immediate extension of service to Corolla Shores on an interim basis.

The March 20, 2001, Order clearly contemplated that water and sewer utility service would be extended to Corolla Shores by the utility ultimately determined to be responsible for providing water and sewer utility service in the area. In that sense, Ocean Club's request for immediate relief is clearly consistent with the intent of the March 20, 2001, Order. On the other hand, the

Commission has two principal concerns about the appropriateness of Ocean Club's request for interim relief. First, the Commission has not to date determined the best way in which to have water and sewer utility service provided in the Buck Island-Corolla Shores-Monteray Shores area. Although the Commission tends to believe, on the basis of the existing record and its general expertise in the area of water and sewer utility operations, that the most efficient way to provide water and utility service to end user customers in the Buck Island, Corolla Shores, and Monteray Shores developments is to require the interconnection of the facilities available to serve all three developments, the existing record does not address that question in any detail. This is, in fact, a principal reason that the Commission required the entity ultimately determined to be responsible for providing water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores developments to present a plan for serving all three areas that included a recommendation concerning the extent to which additional facilities needed to be built to ensure the provision of adequate water and sewer service in all three areas at full buildout and the manner in which the cost of constructing any additional facilities should be borne by the entities developing each area. As should be obvious from reading the March 20, 2001, Order, the Commission has simply not reached a decision as to the manner in which utility operations should be conducted in Buck Island, Corolla Shores, and Monteray Shores developments following the unification of the ownership of and control over the facilities used to provide service in those area. Secondly, the Commission's principal interest in connection with this proceeding lies in ensuring the provision of adequate and reliable water and sewer utility service to the end user customers located in each area. Although the Commission understands that Ocean Club's development interests would be served by the immediate provision of service to the Corolla Shores area, the Commission does not view Ocean Club's development interests as completely equivalent to the interests of actual end user customers in obtaining continued reliable water and sewer utility service. As a result, the Commission would be unwilling to order the immediate provision of service to the Corolla Shores area if such an action would result in deficient service to end users located in Buck Island or Monteray Shores. Ocean Club's repeated emphasis upon the Commission's decision to award interim relief to Currituck County in Docket No. W-354, Sub 231, overlooks the fact that the record developed at the hearing in that proceeding, unlike the record in this case, established that water and sewer utility service could be extended to the public restrooms at the Whalehead Club without risk of impairing service to existing and future customers in the Corolla Light because Outer Banks Ventures had planned to make sufficient capacity available to provide service at the public restrooms. The record developed prior to the entry of the March 20, 2001, Order did not permit the Commission to determine with an equal degree of assurance that granting Ocean Club's request for interim service would not unfairly prejudice end users located in Buck Island and Monteray Shores, particularly given the Commission's conclusion that financial responsibility for ensuring the availability of sufficient facilities to ensure the provision of adequate service in each area should rest upon the developer, at least in the first instance.

The Commission attempted to address the second of these concerns by issuing the Order Requesting Additional Information. Although the information submitted by the parties in response to the Commission's request was not completely consistent, a few things are clear from a close examination of that information. First, as the Commission intimated in the March 20, 2001, Order, the existing facilities are not sufficient to serve anticipated end user customers in all three developments at full buildout. Secondly, given that there is no actual demand for water and sewer capacity in Corolla Shores at the present time, the existing facilities are sufficient to provide adequate service in all three areas for the immediate future. Thirdly, the parties' filings suggest that, given anticipated growth in the demand for water and sewer utility service in all three affected areas, the Commission cannot be certain that there will be sufficient water production and wastewater treatment capacity to ensure the provision of adequate service to end users in all three areas by the beginning of the peak summer season in June, 2002. As a result, the available information suggests that interim relief could be provided while ensuring a reasonable degree of reliability for end users in all three areas for approximately the next year, but that, after that time, new facilities would be needed in order to ensure that adequate service would be provided to all affected end user customers.

As has been previously noted, the Commission is sympathetic to the impact of the pendency of this litigation on Ocean Club's development plans. Although the Commission is not, as has been repeatedly stated, primarily concerned with the impact of its decisions on the Currituck County development process, we fully understand the necessity for Ocean Club to demonstrate the availability of adequate water and sewer utility service in order to proceed with its development activities. Having previously determined that the Corolla Shores development is contained within Carolina Water's franchised service territory and that end user customers located within a utility's service territory are entitled to service to the extent that it can be reasonably made available, we are not insensitive to Ocean Club's concern that the March 20, 2001, Order gave it a right without an effective remedy. Although the Commission had been of the opinion that the procedures outlined in the March 20, 2001, Order would result in the extension of service to Corolla Shores in an orderly and reasonably expeditious manner, subsequent developments have established that there is no reasonable likelihood that service will be extended to Corolla Shores in the near future utilizing the procedures outlined in the March 20, 2001, Order. As a result, the Commission concludes that service should be extended to Corolla Shores on an interim basis, subject to the imposition of certain terms and conditions necessary to protect end users in Buck Island and Monteray Shores and to ensure the provision of adequate and reliable water and sewer utility service throughout the relevant area both now and in the future.

At the present time, Carolina Water is functioning as the water and sewer utility responsible for providing service in Buck Island and Monteray Shores. As a result of the fact that Carolina Water Service has been certificated as a utility in many service territories in North Carolina for many years, the Commission is well aware that Carolina Water Service and its affiliates are adequately capitalized and professionally operated. Although Monteray Shores contends that it should be given the responsibility for providing water and sewer utility service in Buck Island and Monteray Shores, the Commission has little information about the extent of its capacity to serve as an adequately capitalized and professionally operated water and sewer utility. In addition, Monteray Shores appears to have expressed its interest in becoming a certificated water and sewer utility only after it became apparent that the Commission might require the use of water production and wastewater treatment facilities currently owned by Monteray Shores and Ship's Watch to provide service in Corolla Shores. Under the circumstances, the Commission concludes that, until further order of the Commission and without prejudice to the right of Monteray Shores and Ship's Watch to advocate a different result on a long term basis, Carolina Water Service should continue to be designated as the utility responsible for providing water and sewer service in the Buck Island, Corolla Shores, and Monteray Shores developments.

The Commission further concludes that, pending the resolution of the further proceedings contemplated in this Order and the March 20, 2001, Order, it appears that the most efficient way to provide water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores developments given current conditions is for the existing facilities in all three areas to be interconnected and utilized to serve end user customers in all three developments. The Commission makes this determination on the basis of its tentative conclusion that interconnecting all facilities in the relevant areas is the most efficient way to provide water and sewer utility service to end user customers there. The Commission's conclusion is buttressed by Carolina Water Service's contentions concerning the most efficient way to serve the relevant area. Although the Commission is well aware that a decision to require the interconnection of facilities in Monteray Shores and Buck Island with facilities in Corolla Shores has certain implications under the Currituck County development ordinance and will order that a copy of this Order be served upon the County for that reason, the Commission does not believe that this factor justifies the adoption of a less efficient means of providing water and sewer utility service in the affected areas. This is particularly true given the fact that the relief granted in this Order is interim in nature and subject to alteration or even revocation in the event that the record developed in subsequent proceedings indicates that a different approach is preferable on a longer term basis. The Commission further notes that the March 20, 2001, Order requires Ocean Club to pay for the additional water production and wastewater treatment facilities needed to serve the demand for water and sewer utility service in Corolla Shores at full buildout, a factor which provides further protection to the interests of Monteray Shores and Ship's Watch. As a result, the Commission concludes that Carolina Water Service should provide interim service in Corolla Shores by interconnecting facilities in Corolla Shores with the existing facilities utilized to provide water and sewer utility service in Buck Island and Monteray Shores and utilizing those facilities to provide water and sewer utility service in all three areas pending further order of the Commission.

The Commission recognizes the likelihood that, at some point in the future, the facilities currently available for providing service in the Buck Island, Corolla Shores, and Monteray Shores developments will be insufficient to meet anticipated demand. According to our analysis of the information provided in response to our Order Requesting Additional Information, the demand anticipated in all three areas is likely to outstrip the capacity of the available water production and wastewater treatment facilities by the beginning of the summer peak season in June 2002. As a result, the Commission must give serious consideration to the steps that should be taken in the event that such a capacity shortage occurs. Although the Commission hopes that the parties will be well on their way to the development and implementation of a plan for providing service to all affected areas on a long term basis in accordance with the intent of the March 20, 2001, Order, the Commission also recognizes that there can be no assurance that adequate progress will be made toward the development and implementation of a long term solution by the time that the capacity of the available facilities is exhausted. In the event that such capacity exhaust occurs, the Commission concludes that priority should be given to end users in the Buck Island and Monteray Shores developments, since Monteray Shores and Ship's Watch have provided the financial support for the construction of the existing wells and sewer treatment facilities and, presumably, recouped the cost of that investment through the sale of property to end users in their respective developments. End users in those areas purchased property in Buck Island and Monteray Shores on the understanding that adequate water and sewer capacity would be available to serve their needs, and the Commission has no intention of upsetting or disturbing those settled expectations. As a result, the Commission concludes that, in the event that Carolina Water Service determines that the demand for water and sewer service in Buck Island, Corolla Shores, and Monteray Shores has outstripped the capacity of the available water production and wastewater treatment facilities, it should, after giving three months notice to Ocean Club, any end user customers in Corolla Shores, the Commission, and the other parties to this proceeding, sever or block the interconnection between the systems currently used to provide service in Buck Island and Monteray Shores and the distribution and collection facilities located in Corolla Shores or take such other steps as are needed to ensure the provision of adequate water and sewer utility service in Buck Island and Monteray Shores. The Commission is confident that Carolina Water Service will exercise this authority in a responsible manner and will provide Ocean Club and end users located in Corolla Shores with as much notice as possible in the event of a capacity deficiency in order to provide the maximum opportunity for making alternative arrangements.

The Commission is well aware that this approach requires Ocean Club to assume certain risks as it attempts to develop the Corolla Shores property. In order to protect Ocean Club's customers, the Commission will require Ocean Club to provide full disclosure to any party to whom it sells property in Corolla Shores of the circumstances under which service is provided pursuant to this Order. The Commission does not know how to provide any interim relief to Ocean Club on any other basis without significant unfairness to end user customers located in Buck Island and Monteray Shores. As a result, Ocean Club will, necessarily, be required to proceed at its own risk. On the other hand, the Commission hopes that the provision of service to Corolla Shores will be permanent in nature instead of temporary and short-lived. For that reason, the Commission hereby places all parties, including Ocean Club, on notice that all parties are expected to act reasonably in connection with the implementation of the interim relief provided under this Order and that the Commission will not hesitate to take appropriate action in the event that any party fails to act in that manner. Thus, Ocean Club is hereby placed on notice that it should remain in constant contact with Carolina Water during the period prior to the complete implementation of the March 20, 2001, Order for the purpose of making sure that it is aware of the overall water and sewer service supply situation in the relevant area and that it should develop backup plans to ensure that any end user customers located in Corolla Shores have access to alternative sources of water and sewer service in the event that Carolina Water Service is required to sever or block the interconnection between the facilities located in Buck Island and Monteray Shores and those located in Corolla Shores. In addition, Monteray Shores and the DeGabrielles should refrain from doing anything outside the scope of ordinary development activities that would accelerate the date upon which the existing water and sewer facilities become inadequate to serve Buck Island, Corolla Shores, and Monteray Shores. Finally, the Commission urges Carolina Water Service to continue attempting to work with all parties for the purpose of avoiding unnecessarily adverse consequences to any end user in Buck Island, Corolla Shores, and Monteray Shores developments. Such cooperation is imperative if the parties are to avoid further Commission action.

The Commission does not intend for the this award of interim relief to any way overshadow the importance of continued efforts to comply with the procedures outlined in the March 20, 2001, Order. On the contrary, the Commission remains hopeful that the parties will work together to develop and implement a result which is consistent with that contemplated in the March 20, 2001, Order. For that reason, the provisions of the March 20, 2001, Order, to the extent that they are not inconsistent with the provisions of this Order, remain in full force and effect. The Commission wants to be clearly understood as being committed to the implementation of a long-term solution of the type contemplated in the March 20, 2001, Order even if the parties are unable to reach agreement on the best manner in which to achieve that end. As a result, the Commission reserves jurisdiction over this matter for the purpose of conducting such additional proceedings and issuing such additional orders as are necessary to implement a final solution to the problems which have been identified in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That this matter is hereby scheduled for hearing on Tuesday, September 11, 2001, at 9:30 a.m. in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, for the purpose of considering the following issues:

(a) The extent to which Ship's Watch should be declared a de facto utility subject to the Commission's regulatory jurisdiction pursuant to G.S. 62- 3(23)a.2;

(b) A determination of the identity of the entity which should provide water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores developments as contemplated by Decretal Paragraph 2 of the Commission's March 20, 2001, Order;

(c) The manner in which the water production and wastewater treatment facilities used to serve the Buck Island and Monteray Shores developments should be brought under common ownership and control;

(d) The manner in which the existing agreement between Carolina Water Service, Ship's Watch, and Monteray Shores should be modified to ensure common ownership and control of the water production and wastewater facilities used to provide service in the Buck Island and Monteray Shores developments;

(e) The nature of any steps which should be taken to protect the interests of Ship's Watch and the individuals and businesses owning property in the Buck Island development as the Commission attempts to assure the provision of adequate and reliable water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores developments.

2. That Ship's Watch is hereby required to show cause at the September 11, 2001, hearing why it should not be found to be a utility subject to the Commission's regulatory jurisdiction pursuant to G.S. 62-3(23)a.2 and is, for that and other appropriate purposes, made a party to this proceeding.

3. That a copy of this Order shall be served upon Ship's Watch by the Chief Clerk's office in the same manner utilized in connection with the service of complaints and show cause orders.

4. That, pending further order of the Commission and subject to the remaining provisions of this Order, Carolina Water Service is designated the sole entity entitled to provide water and sewer utility service in the Buck Island, Corolla Shores, and Monteray Shores developments and shall act in that capacity without interference from any other party.

5. That, pending further order of the Commission and subject to the remaining provisions of this Order, Carolina Water Service shall provide water and sewer utility service to the Corolla Shores area by interconnecting any water distribution and sewer collection lines used to serve the Corolla Shores development with the facilities that Carolina Water Service currently utilizes to provide water and sewer utility service in the Buck Island and Monteray Shores developments.

6. That, in the event that Carolina Water Service determines at any point prior to the final disposition of this proceeding that the water production and wastewater treatment facilities available to provide service in the Buck Island, Corolla Shores, and Monteray Shores developments lack sufficient capacity to provide adequate and reliable water and sewer utility service to all three developments and after providing three months notice to Ocean Club, all end user customers receiving service in Corolla Shores, the Commission, and all parties to this proceeding, Carolina Water Service shall cease providing water and sewer service in the Corolla Shores development and shall sever or block the interconnection between the existing service facilities and the water distribution and sewage collection facilities installed in the Corolla Shores development.

7. That Ocean Club shall make full and truthful disclosure to any party to whom it sells property in Corolla Shores of the circumstances under which interim service is provided pursuant to this Order.

8. That no party to this proceeding shall take any action which shall in any way be inconsistent with the provisions of this Order or tend to frustrate the provision of the service contemplated by this Order.

9. That, except to the extent inconsistent with this order, the provisions of the March 20, 2001, Order remain in full force and effect.

10. That a copy of this Order shall be delivered to the County Manager of Currituck County by the Chief Clerk's office.

11. That the Commission shall retain jurisdiction over this proceeding to the extent necessary to resolve any further issues which may arise between the parties during their efforts to comply with the terms and conditions of this Order and the March 20, 2001, Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 17th day of August, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

rg081601.01

DOCKET NO. W-215 SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Coastal Plains Utilities Company, P.O. Box 3684, Wilmington, North Carolina, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina	))))	RECOMMENDED ORDER GRANTING PARTIAL INCREASE IN RATES

HEARD IN: Superior Courtroom 317, Judicial Building, 314 Princess Street, Wilmington, North Carolina, on October 25, 2000, at 7:00 p.m.

BEFORE: Danny Stallings, Hearing Examiner

APPEARANCES:

For Coastal Plains Utilities Company:

(No Attorney of Record)

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

STALLINGS, HEARING EXAMINER: On May 30, 2000, Coastal Plains Utilities Company (Applicant), filed an application with the Commission seeking authority to increase it rates for water utility service in all its service areas in New Hanover County, North Carolina. The Applicant also filed a request for interim rates. On June 28, 2000, the Commission issued an Order declaring the matter a general rate case, suspending the proposed rates for up to 270 days, granting interim rate relief, scheduling the matter for public hearing, and requiring customer notice. The Order also provided that the hearing could be canceled if no significant protests were received and the proposed rates were found to be reasonable.

On September 22, 2000, the Applicant filed the Certificate of Service indicating that customer notice had been given in accordance with the Commission's Order.

On October 5, 2000, the Public Staff filed the testimony of Kathy Fernald, Accounting Supervisor with the Public Staff's Accounting Division; Jay Lucas, Utilities Engineer with the Public Staff's Water Division; and a Notice of Affidavit and Affidavit of Calvin C. Craig, III, Financial Analyst with the Public Staff's Economic Research Division.

The Commission received several protests in response to the customer notice.

The hearing on the matter was held as scheduled. The Public Staff presented the testimony of Mr. Jay Lucas and Ms. Kathy Fernald, and the Affidavit of Calvin Craig was admitted into evidence. The following public witnesses testified: Teresa James and Christine Neal.

Based upon the application, the Commission's records, the testimony of witnesses, the evidence introduced at hearing and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. Coastal Plains Utilities Company is a public utility as defined by G.S. 62-3(23) and is before the Commission pursuant to its application for an increase in its rates and charges for water utility service under G.S. 62-133.

2. The Company has not had a rate increase since 1983.

3. The test year appropriate for use in this proceeding is the 12-month period ended December 31, 1999.

4. The Applicant's rates at the time it submitted its rate increase application and proposed rates are as follows:

	Existing	Proposed
Metered Residential Water Rates:		
Base charge, includes 3,000 gallons	$ 8.50	$10.00
Usage, per 1,000 gallons (Above 3,000 gallons)	$ 1.00	$ 1.75
Flat Rate Residential Water Rates:	$12.00	$18.00
Metered Non-Residential Water Rates:		
Base charge, includes 10,000 gallons	$35.00	$40.00
Usage charge per 1,000 gallons (Above 10,000 gallons)	$ 1.00	$ 2.00

5. The Applicant has requested rates designed to produce additional annual revenues of $54,149.

6. The Applicant's interim rates are as follows:

Metered Residential Water Rates:

Base charge, includes 3,000 gallons	$10.00
Usage, per 1,000 gallons (Above 3,000 gallons)	$ 1.50

Flat Rate Residential Water Rates: $14.65

Metered Non-Residential Water Rates:

Base charge, includes 10,000 gallons	$35.00 (no change)
Usage charge per 1,000 gallons (Above 10,000 gallons)	$ 1.00 (no change)

7. The Public Staff recommended rates as follows:

Monthly Flat Rate: $14.92

Monthly Metered Residential Rates:

Base charge, no usage	$ 5.95
Usage charge, per 1,000 gallons	$ 1.22

Monthly Metered Commercial Rates:

Base charge, no usage	$ 9.50
Usage charge, per 1,000 gallons	$ 1.22

8. The rates recommended by the Public Staff, and agreed to by the Applicant are designed to produce additional revenues of $23,184.

9. The original cost rate base for use in this proceeding is $54,837, consisting of plant in service of $334,312, plus cash working capital of $14,067, less accumulated depreciation of $292,180 and average tax accruals of $1,362.

10. The annualized level of service revenues under the Company's present rates is $112,460.

11. The appropriate level of operating revenue deductions requiring a return (excluding gross receipts tax, regulatory fee and income taxes) is $117,477.

12. The operating ratio method, which allows a margin on operating revenue deductions requiring a return, is the proper method for determining the Company's revenue requirement.

13. A margin of 8.5% on operating revenue deductions requiring a return is just and reasonable for use in this proceeding.

WATER AND SEWER - RATES

14. The annual level of total revenues necessary to allow the Company the opportunity to earn an 8.5% margin is $135,644. This amount results in an increase of $23,184 over the Company's existing rates.

15. The Applicant requested interim rates of $16.00 per month for flat rate water service, but the Commission approved only $14.65. The Applicant started billing flat rate customers $16.00 per month. Some customers wrote to the Commission explaining the error, and the Public Staff brought it to the Applicant's attention. The Applicant acknowledged the error and agreed to credit the amount that was overcharged to the customers' accounts.

16. The customers of the Company have poor water pressure and water quality; however, the testing levels pertaining to water quality in the Company's service areas have met State requirements.

17. The general quality of water utility service provided to the customers of Coastal Plains has been marginal primarily because of the age of the system, and the general deterioration of the Company's pipes and the prevalence of rust and corrosion in the pipes, and the Company has not been able to adequately remedy all of the problems with its systems. Although the witnesses who testified at the hearing indicated that their water pressure has improved, the pressure has not improved in all of the Applicant's service areas.

18. The Public Staff had the following recommendations for necessary improvements to the following systems. These recommendations were agreed to by the Company.

<u>Wilmington Beach/Hanby Beach System</u>

This system needs an emergency connection to the Town of Kure Beach water system. The flow meter at the Hanby Beach well house needs to be cleared of debris and readings taken by the operator at each visit.

<u>Brookfield/Brierwood System</u>

The pressure tank at Well No. 1 had a slight leak and needs repair on the center foundation support. The drain valve points toward the foundation and erodes the soil from the foundation when the tank is drained.

<u>Greenview Ranches/Oak Ridge System</u>

The well house for the Greenview Ranches/Oak Ridge system needs paint.

19. The recommendations made by the Public Staff relating to improvements that need to be made to the Applicant's systems are reasonable and justified.

20. The Towns of Kure Beach and Carolina Beach have recently annexed the entire service area serving the Wilmington Beach and Hanby Beach areas. The Towns, with the assistance of New Hanover County, are constructing water lines that will parallel this system and should have construction completed by October 2001. The Applicant has indicated that it will request that the Commission allow it to discontinue service to this area when the project is completed.

21. The Public Staff recommended the following improvements to the operations of the Applicant: (1) meters should be installed for all users of the Brookfield/Brierwood water system; and (2) all three systems should have emergency or permanent connections with the nearest municipal water system.

22. Customers complained about the problems with water outages due to power failure, and requested that the Company be required to purchase a generator for the system.

23. There was minimal testimony from the Company regarding the costs of obtaining a generator, and other related issues. It was established that if the Company purchased a generator, the costs associated with it would be recouped in another application for rate increase.

24. In accordance with the recommended rates set forth in Finding of Fact No. 7, the Company should be allowed a partial increase in its annual revenues for water utility service of $23,184. These rates are approved as the proper rates in this proceeding.

25. The Applicant shall remit to its customers the difference between the interim rates that it charged and the rates approved in this proceeding, in accordance with the Order of the Commission dated June 28,2000.

26. Regarding pursuing the option of the purchase of water from New Hanover County or other options pursued with the county water system, the Public Staff shall assist the Company and the New Hanover County Water and Sewer Department in facilitating either the purchase of water from the county or the transfer of the Coastal Plains system to the county.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-8

The evidence for these findings of fact is contained in the application, testimony and exhibits of Public Staff witnesses Fernald and Lucas and the Commission's records. This evidence is uncontroverted.

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

The evidence supporting these findings of fact is contained in the testimony and exhibits of Public Staff witnesses Fernald and Lucas. At the hearing, the Company did not present any evidence contesting the Public Staff's levels of rate base, revenues, and expenses.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-13

The evidence supporting these findings of fact is contained in the Affidavit of Public Staff witness Craig and the testimony and exhibits of Public Staff witness Fernald. The Company did not contest the 8.5% margin on operating revenue deductions proposed by Witness Craig. The Company's rate base is less than the reasonable level of operating expenses in this proceeding. Therefore, the Hearing Examiner concludes that the operating ratio method, which allows a margin on operating revenue deductions requiring a return, is the proper method for determining the Company's revenue requirement. Furthermore, a margin of 8.5% on operating revenue deductions is just and reasonable for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

Based upon the foregoing findings and conclusions, the Hearing Examiner concludes that a total annual revenue requirement of $135,644 will allow the Company the opportunity to earn a margin of 8.5% on its operating revenue deductions requiring a return. The following schedules summarize the gross revenues, operating revenue deductions, and rate base based upon the conclusions reached elsewhere in this Order.

SCHEDULE I

COASTAL PLAINS UTILITIES COMPANY
DOCKET NO. W-215, SUB 18
STATEMENT OF OPERATING INCOME FOR RETURN
For the Twelve Months Ended December 31, 1999

Item	Present Rates	Increase Approved	After Approved Increase
Operating revenues:			
Service revenues	$112,460	$23,184	$135,644
Operating revenue deductions:			
Salaries and wages	22,500	0	22,500
Contract labor	39,187	0	39,187
Administrative and office	4,047	0	4,047
Telephone expense	4,954	0	4,954
Maintenance and repairs	7,335	0	7,335
Transportation	6,579	0	6,579
Electric power	12,955	0	12,955
Testing	2,926	0	2,926
Chemicals	7,737	0	7,737
Permit fees and licenses	1,761	0	1,761
Rate case expense	986	0	986
Insurance expense	551	0	551
Miscellaneous expense	1,021	0	1,021
Total operating & maintenance expense	112,539	0	112,539
Depreciation expense	3,715	0	3,715
Property taxes	1,223	0	1,223
Regulatory fee	101	21	122
Gross receipts tax	4,498	928	5,426
State income tax	0	871	871
Federal income tax	0	1,762	1,762
Total operating revenue deductions	122,076	3,582	125,658
Net operating income for return	($9,616)	$19,602	$9,986
Operating revenue deductions requiring a return	$117,477		$117,477
Margin	-8.19%		8.50%

SCHEDULE II

COASTAL PLAINS UTILITIES COMPANY
DOCKET NO. W-215, SUB 18
STATEMENT OF ORIGINAL COST RATE BASE
For the Test Year Ended December 31, 1999

Item	Amount
Plant in service	$334,312
Accumulated depreciation	(292,180)
Net plant in service	42,132
Cash working capital	14,067
Average tax accruals	(1,362)
Original cost rate base	$54,837

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is in the testimony of Public Staff witness Jay Lucas, and in the testimony of Company witness, George Allie Moore, and is uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding is supported by the testimony of the public witnesses who testified in the hearing in this docket, and Company witness Moore.

Public witness Teresa James lives in the Brierwood Subdivision, which is served by Coastal Plains Utilities Company. She testified that because of the poor water quality, her toilets, bathtubs, and sinks are discolored, requiring her to use caustic chemicals to clean them. According to Ms. James, there is sediment left in the bottom of her glasses if water is left to sit in them. Further, as a result of the discolored water, the witness put three filters on her house, as well as a filter on her icemaker, because her icemaker was producing orange colored ice.

Ms. James testified that the water pressure was not just a seasonal problem, but year round. She recounted numerous times when she came home from work and after checking found the water pressure below 28 pounds. She said, however, in the six to eight weeks prior to the hearing, the Company repaired a well, and the water pressure in her home has improved, but the quality has not.

Ms. James further stated that if the Company does not provide continuously adequate water pressure, better water quality, and obtain an emergency generator, it should not receive a rate increase.

Additionally, Ms. James offered into evidence several used filters from her water filtering system, which were identified as James Exhibit 1. The filters were covered with black specks. She stated that she had to change these filters every 30 hours.

Ms. Christine Neal, a customer in the Brookfield Subdivision, testified that her water pressure has also improved, but she is still subject to limitations in terms of using the shower, or another source of water in the household at the same time. The water pressure continues to fluctuate from good to bad on certain days according to Ms. Neal.

Ms. Neal stated that she opposed the option of purchasing water from the county unless meters are installed. She is totally against any increase in the Company's rates at all.

Regarding water quality, she stated that she does not have a problem with sediment in her water, but has rust. Ms. Neal, who stated that she is employed by the New Hanover County Engineering Department, acknowledged, however, that there is a rust problem with most of the water systems in all of New Hanover County.

Notwithstanding the foregoing complaints of the public witnesses in this docket, witness George Allie Moore provided uncontroverted testimony that the water was tested regularly and was deemed acceptable by State standards. According to Mr. Moore, a bacteriological and chemical analysis are collected by an operator certified by the State of North Carolina to collect these samples, and no bacteria or other harmful chemicals were found according to the required tests that were run. Additionally, Mr. Moore testified that copies of the Company's 1999 and 2000 water quality reports, which were made by a state certified operator, were sent to the customers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

The evidence supporting this finding of fact is contained in the testimony of the public witnesses, Public Staff witness Jay Lucas, Company witness Moore, and contained in the formal complaints filed with the Commission since the subject rate increase application has been filed. The Hearing Examiner takes notice of the testimony of the Applicant's customers who filed formal complaints in other dockets after the Applicant's rate increase application was filed. In Docket No. W-215, Sub 19, during the hearing held on October 19, 2000, there was substantial testimony from witnesses who stated that they have not seen an improvement in their water pressure.

Mr. Moore admitted in his testimony that there are problems with his system. He stated that many of the homes in his service areas are over 25 years old and have old galvanized pipe, which after many years will develop a buildup inside the pipe. At the complaint hearing in Docket No. W-215, Sub 19, Mr. Moore also testified that there is an iron problem in the system, and that he uses flushing as a means to alleviate this problem, but there is still a problem. He testified that each system is flushed on a certain schedule; and he flushes the lines of the customers in the Brookfield and Brierwood subdivisions on a four-week schedule. The public witnesses could not confirm nor refute this, but they had never been given notice of the Company's flushing schedule.

Company witness Moore, confirmed that he has not been giving his customers notice of when he intends to flush the system, but agreed to give written notice of the flushing schedule and include it with the monthly bill.

The public witnesses both testified that Mr. Moore had recently made repairs to the system, and their water pressure has improved. However the customers who live in the Greenview Ranches subdivision who filed a formal complaint in Docket No. W-215, Sub 19, and testified at a hearing on that matter, stated that their water pressure has not improved.

Based on the foregoing, the Hearing Examiner concludes that the water utility service provided by the Company has been marginal in terms of the Company's inability to provide clear water and constant water pressure at all times. There was evidence, however, that the Applicant made efforts to remedy the problem with the water pressure and with the rust and iron in its customers' water by flushing the system, and coming out to repair leaky water lines, although it might not have been immediately. Additionally, there was no evidence that the witnesses contacted the Company directly with complaints and the Company failed to follow-up on the complaints. Ms. James testified that she contacted the Company "several years ago" with a complaint, but has not contacted the Company within the past year.

Because of the age of the system and the condition of its water lines, there might not be much that the Applicant can do to permanently correct its problems, short of replacing all the lines in its system, which would be a costly proposition. According to Commission files, the Applicant has not had a rate increase since 1983, and the Hearing Examiner concludes that it is reasonable to believe that the Company will need additional funds to survive and to make the improvements recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 18-19

The evidence supporting these findings of fact is found in the testimony of Public Staff witness Jay Lucas, and Company witness George Allie Moore.

The Hearing Examiner concludes that the improvements recommended by the Public Staff and agreed to by the Company are just and reasonable and should be implemented by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Jay Lucas.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

The evidence supporting this finding of fact is found in the testimony of Public Staff witness Jay Lucas, and the testimony of the public witnesses.

Mr. Allie Moore, testifying for the Applicant did not object to the recommendations of the Public Staff; however, he made it clear that additional funds would be needed to accomplish these objectives. Although the Public Staff offered into evidence a letter sent to Mr. Moore requesting estimates for installing meters, Mr. Moore has not provided this information.

The Hearing Examiner concludes that based on the testimony of the Public Staff and public witnesses, the improvements recommended are reasonable, and should be investigated by the Company. The costs associated with these improvements, however, will have to be just and reasonable and recouped in a subsequent rate case filing. The Hearing Examiner advises the Company to seek the assistance of the Public Staff while pursuing these improvements.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 22-23

The evidence for these findings is found in the testimony of the public witnesses Ms. Neal and Ms. James.

Ms. Neal testified that she sees a need for a generator in order to back up the system. Both witnesses testified that outages were primarily due to problems with CP&L, or occurred after hurricanes. They also testified that there have not been any outages since the last hurricane.

The Hearing Examiner acknowledges that the customers must have experienced extreme hardship when the power failed, thus causing the Company's pump to fail such that water was not available to its customers. However, these outages were unavoidable and out of the Company's control. Mr. Moore testified that the acquisition of a generator is a costly endeavor, and the Company is not financially able to purchase one. If the Company purchased a generator, it could file a subsequent rate increase application to have the cost included in its customers' rates. Since there has been evidence that the customers in the Wilmington Beach and Hanby Beach service areas will eventually be served by the county water system, and this option is being investigated for the other service areas as well, this expense might not be prudent at this time. If such a purchase were made and justified and the Commission approved of including it in the Company's rates, the cost would be spread among a few customers who remained on the system, causing a greater increase in their water rates.

Based on the testimony presented at the hearing, and without additional evidence, the Hearing Examiner will not address the purchase of generators by the Company at this time. If the Company does purchase a generator for its system and wishes to include the cost in its rates, it will have to file a subsequent application for a rate increase.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence for this finding is supported by the revised testimonies of Public Staff witnesses Lucas and Fernald, and supported by the testimony of the Company.

Based upon the findings concerning the Company's operating revenues, and operating revenue deductions, the Hearing Examiner concludes that Coastal Plains Utilities Company should be allowed a partial increase in its water service revenues of $23,184 in order to have the opportunity to earn a

8.5% margin on operating revenue deductions requiring a return, which is fair and reasonable. Accordingly, the rates set forth in Appendix A, attached hereto, are approved as the proper rates for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence for this finding of fact is supported by the testimony of Public Staff witness Lucas, Company witness Moore, and the Commission's Order of June 28, 2000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence for this finding of fact is supported by the testimony of Public Staff witness Jay Lucas.

Based upon the entire record in this proceeding, the Hearing Examiner is of the opinion that the Applicant has sufficiently demonstrated the need to increase its rates for water utility service in New Hanover County, North Carolina. The Hearing Examiner also recognizes that the improvements noted above need to be made. The Applicant has agreed to Public Staff Engineer Lucas' recommendations and has accepted the Public Staff's proposed rates. The Hearing Examiner therefore concludes that the rates recommended by the Public Staff and set forth in the attached Schedule of Rates and accepted by the Applicant are just and reasonable and should be approved, and that the improvements noted above should be made.

IT IS, THEREFORE, ORDERED as follows:

1. The Applicant is required to refund the sums due its customers as result of charging an excessive interim rate. The Applicant shall file a refund plan with the Commission within 30 days of the effective date of this Order.

2. That the Applicant is authorized to increase its rates for water utility service in its service area in New Hanover County, North Carolina, as reflected in the Schedule of Rates, attached hereto as Appendix A. These rates shall be effective for service rendered on and after the effective date of this Order.

3. The Schedule of Rates is deemed to be filed with the Commission pursuant to G.S. 62-138.

4. That the Applicant establish a program to correct the deficiencies in the water utility systems as stated in Finding of Fact No. 18 and investigate the feasibility of purchasing water or connecting all of its systems to an alternate water supply.

5. That the Public Staff shall monitor the progress of the Applicant in making necessary improvements, and assist the Applicant in making progress on investigating and/or facilitating the procurement of water or water services from an alternate source.

6. That the Notice to Customers of Increase in Rates, attached hereto as Appendix B, shall be mailed or hand delivered by the Applicant to all customers within 5 days of the effective date of this Order; and that the Applicant submit the attached Certificate of Service properly signed and notarized not later than 30 days after the effective date of this Order.

ISSUED BY ORDER OF THE COMMISSION
This the 4th day of January 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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APPENDIX A

SCHEDULE OF RATES

for

Coastal Plains Utilities Company

for providing water utility service in

All Its Service Areas

New Hanover County, North Carolina

Monthly Flat Rate:	$14.92

Monthly Metered Residential Rates:

Base charge, no usage	$ 5.95
Usage charge, per 1,000 gallons	$ 1.22

Monthly Metered Commercial Rates:

Base charge, no usage	$ 9.50
Usage charge, per 1,000 gallons	$ 1.22

Meter Fee:

New customers desiring to be supplied water at a metered rate will pay a fee of $200.00. This fee may be paid over a four-month period at $50.00 per month. This fee is not required if the customer's lot has functioning meter.

Charge for New Connections:

For the Wilmington Beach/Hanby Beach and Brookfield/Brierwood systems:

3/4-inch connection:	$400.00
>3/4-inch connection:	Actual cost

For the Greenview Ranches/Oak Ridge system:

3/4-inch connection:	No charge
>3/4-inch connection:	Actual cost

Reconnection Charge:

If water service cut off by utility for good cause:	$15.00
If water service discontinued at customer's request:	$15.00

WATER AND SEWER - RATES

Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears
Finance Charges for Late Payment:	1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-215, Sub 18, on this the 4th day of January, 2001.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-215, SUB 18

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Coastal Plains Utilities Company	)	NOTICE TO CUSTOMERS
for Authority to Increase Rates for Water Utility	)	OF PARTIAL INCREASE
Service in All Its Service Areas in New Hanover	)	IN RATES
County , North Carolina		

BY THE COMMISSION: Notice is given that the North Carolina Utilities Commission has granted a partial rate increase to Coastal Plains Utilities Company for water utility service provided in all of its subdivisions in North Carolina.

The Commission's decision followed customer notice and investigation by the Public Staff as well as a public hearing held in Wilmington, North Carolina, on October 25, 2000.

The Public Staff's investigation and audit revealed that the rates requested by the Applicant were not justified, and made adjustments, and recommended lower rates, which were agreed to by the Applicant. The new rates are as follows and are effective for service rendered on and after the effective date of the Commission's Order.

Monthly Flat Rate:	$14.92
Monthly Metered Residential Rates:	
Base Charge, no usage	$ 5.95
Usage Charge, per 1,000 gallons	$ 1.22
Monthly Metered Commercial Rates:	
Base Charge, no usage	$ 9.50
Usage Charge, per 1,000 gallons	$ 1.22

ISSUED BY ORDER OF THIS COMMISSION.
This the 4th day of January, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

WATER AND SEWER - RATES

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-215, Sub 18 and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of ___________________ 2001.

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-215, Sub 18.

Witness my hand and notarial seal, this the ____ day of ________________ 2001.

____

Notary Public

____

Address

(SEAL) My Commission Expires: ________________________________

Date

DOCKET NO. W-274, SUB 318

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Heater Utilities, Inc. Post Office Drawer 4889, Cary, North Carolina 27519, for Authority to Increase Rates to Increase Rates for Providing Water and Sewer Utility Service in Woodlake in Moore County, North Carolina	)	ORDER APPROVING PARTIAL INCREASE IN RATES

HEARD IN: Commissioner's Meeting Room, Historic Courthouse, Courthouse Square, Carthage, North Carolina, on May 8, 2001, at 7:00 p.m.; and,

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on June 26, 2001, at 10:00 a.m.

BEFORE: Commissioner Lorinzo L. Joyner, Presiding; and Commissioners Sam J. Ervin, IV and Robert V. Owens, Jr.

APPEARANCES:

For the Applicant:

Odes L. Stroupe, Jr., Attorney at Law, Bode, Call and Stroupe, LLP, 3101 Glenwood Avenue, Suite 200, Raleigh, North Carolina 27612

For the Using and Consuming Public:

Kendrick C. Fentress, Staff Attorney, Public Staff, North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4326

For the Intervenors: (Woodlake Property Owners Association and Woodlake Partners)

Laurence A. Cobb, The Sanford Holshouser Law Firm, PLLC, P.O. Box 2447, Raleigh, North Carolina 27602

BY THE COMMISSION: On December 21, 2000, Heater Utilities, Inc. (Heater, Company or Applicant), filed the above-referenced application. By Order issued on January 17, 2001, the North Carolina Utilities Commission (Commission), declared the application to be a general rate case, suspended the proposed rates, required public notice, scheduled hearings, and established testimony filing dates. By Order issued February 6, 2001, the Commission rescheduled the Raleigh hearing.

On April 24, 2001, the Woodlake Property Owners Association and Woodlake Partners (Intervenors), filed a petition with the Commission seeking to intervene, which request was allowed by the Commission Order dated May 3, 2001.

On May 15, 2001, the Applicant prefiled the testimony of William E. Grantmyre, President of Heater; Freda Hilburn, Director Of Accounting, Treasurer and Controller; and Dr. Roger Morin, Heater's rate of return witness, in support of its application.

On May 24, 2001, the Public Staff prefiled the testimony of Gina Y. Casselberry, Utilities Engineer, Water Division; Michelle M. Boswell, Staff Accountant, Accounting Division; and Thomas W. Farmer, Jr., Director, Economic Research Division.

On June 13, 2001, Heater filed the rebuttal testimony of William E. Grantmyre, President, and Jerry H. Tweed, Vice President, and rebuttal testimony and a Response to Customer Concerns prepared by Richard J. Durham, Director of Operations.

Public notice was given to the customers as evidenced by the Certificate of Service filed by Heater on February 22, 2001.

On May 8, 2001, the customer hearing was held in Carthage, North Carolina as scheduled and four witnesses testified on behalf of the Intervenors.

On June 26, 2001, the Applicant, Public Staff and Intervenors filed Joint Stipulations regarding the rates and service.

The Raleigh hearing was held as scheduled on June 26, 2001, and no customers appeared to testify. The Commission accepted the stipulations executed and filed by the Applicant, Public Staff and Intervenors. The prefiled and rebuttal testimony of Heater and the prefiled testimony of the Public Staff were accepted into the record as if given orally from the stand.

Based on the information contained in the Commission files, the verified application, the testimony, the stipulations, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. Heater Utilities, Inc. is a public utility as defined by G.S. 62-3(23) and, as such, is subject to the jurisdiction of and regulation by the North Carolina Utilities Commission. Heater is lawfully before the Commission seeking an increase in rates and charges pursuant to G.S. 62-133.

2. The Applicant's monthly present rates, applied for rates, and rates stipulated to by the Applicant, Public Staff and Intervenors are as follows:

WATER AND SEWER - RATES

METER SIZE	PRESENT WATER	PRESENT SEWER	APPLIED FOR	APPLIED FOR SEWER	STIPULATED WATER	STIPULATED SEWER
<1"	$9.00	$12.00	$ 21.00	$ 42.00	$ 12.11	$ 25.74
1"			52.50	105.00	30.29	64.35
1.5"			105.00	210.00	60.57	128.70
2"			168.00	336.00	96.91	205.92
3"			315.00	630.00	181.71	386.10
4"			525.00	1,050.00	302.86	643.50
6"			1,050.00	2,100.00	605.71	1,287.00
UsageCharge (Per 1,000 gallons)	$2.00	$ 2.00	$ 3.90	$ 7.05	$ 3.51	$ 5.30

The stipulated rates are Heater's approved uniform water rates for Heater's other service areas and Heater's approved metered sewer rates for the former Mid South service areas.

3. The parties have agreed with regard to service that Heater will:

   a. Perform sufficient but not wasteful water distribution system flushing;

   b. Provide the future testing results for chlorine, bacteriological and HPC tests, and the locations of these tests to the Woodlake Property Owners Association; and,

   c. Provide the Woodlake Property Owners Association with a list of names and telephone numbers of contact persons in both Heater's Cary Operations Center and Fayetteville area office.

4. The Public Staff has conducted a complete investigation of Heater's rate base, reasonable operating revenue deductions, and operating revenues.

5. The Public Staff, Intervenors and Heater have agreed that the stipulated uniform rates shown above should be approved by the Commission.

6. The test period established for use in this proceeding is the 12 months ended June 30, 2000.

7. The appropriate level of original cost rate base used and useful in this proceeding is $631,540 for combined water and wastewater operations, as reflected in Public Staff witness Boswell's prefiled testimony on Boswell Exhibit 1, Schedule 2 and supporting schedules.

8. The rates agreed to by the Public Staff, Intervenors and Applicant are just and reasonable and should be approved.

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. Said Schedule of Rates is hereby authorized to become effective for service rendered on and after the date of this Order.

2. That a copy of the Notice to Customers, attached hereto as Appendix B, shall be mailed or hand delivered to all affected customers by Heater in conjunction with the next regularly scheduled billing process.

3. That Heater shall file the attached Certificate of Service, properly signed and notarized, within ten days of completing the requirement of ordering paragraph No. 2.

4. That pursuant to the stipulation filed in this docket, Heater shall:

   a. Perform sufficient but not wasteful water distribution system flushing;

   b. Provide the future testing results for chlorine, bacteriological and HPC tests, and the locations of these tests to the Woodlake Property Owners Association; and,

   c. Provide the Woodlake Property Owners Association with a list of names and telephone numbers of contact persons in both Heater's Cary Operations Center and Fayetteville area office.

5. That the Joint Stipulations filed in this docket by Heater, the Public Staff and the Intervenors on June 26, 2001, be, and the same are hereby, approved; provided, however, that such approval shall have no precedential value in future proceedings.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

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WATER AND SEWER - RATES

APPENDIX A
PAGE 1 OF 3

SCHEDULE OF RATES

FOR

HEATER UTILITIES, INC.

for providing water and sewer utility service at

WOODLAKE, MOORE COUNTY, NC

WATER UTILITY SERVICE - Monthly

Metered Rates:

Base Charge, zero usage -

<1" meter	$ 12.11
1" meter	$ 30.29
1½" meter	$ 60.57
2" meter	$ 96.91
3" meter	$ 181.71
4" meter	$ 302.86
6" meter	$ 605.71

Commodity Charge, measured in gallons or cubic feet -

Per 1,000 gallons	$ 3.51

Reconnection Charges: (1)

If water service cut off by utility for good cause:	$35.00
If water service discontinued at customer's request:	$ 5.00

Connection Charges:

Per residential equivalent unit	$800.00
Irrigation meter installation fee	$300.00

New Customer Account Fee: $ 20.00

WATER AND SEWER - RATES

SEWER UTILITY SERVICE - Monthly

Metered Rates Based on Water Usage

Meter Size	Base Monthly Charge for Zero Usage
<1" meter	S 25.74
1" meter	S 64.35
1½" meter	S 128.70
2" meter	S 205.92
3" meter	S 386.10
4" meter	S 643.50
6" meter	S1,287.00

Usage charge, per 1,000 gallons S 5.30

Connection Charges: $800 per residential equivalent unit

Reconnection Charges: (1)

If sewer service cut off by Utility for good cause by disconnecting water:	None
If sewer service cut off by Utility for good cause by any method other than noted above:	Actual Cost

Grease Traps:

Utility may require installation and/or proper operation of grease traps on grease producing commercial facilities. Failure to properly operate grease traps will result in disconnection of service pursuant to Commission Rule R10-16.

New Customer Account Fee: $20.00

If customer receives both water and sewer utility service from Heater, then the customer shall only be charged a new account fee for water.

APPENDIX A
PAGE 3 OF 3

OTHER MATTERS

Returned Check Charge:	$25.00
Bills Due:	On billing date
Bills Past Due:	15 days after billing date
Billing Frequency:	Shall be monthly for service in arrears

Finance Charges for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date

Availability Rates:

Water - $5.00 per month
Sewer - $3.75 per month

(1) When service is disconnected and reconnected by the same unit owner within a period of less than nine months, the entire flat rate and/or base charge rate will be due and payable before the service will be reconnected.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-274, Sub 318, on this the 28th day of June, 2001.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-274, SUB 318

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Heater Utilities, Inc.,	)	
Post Office Drawer 4889, Cary, North	)	
Carolina 27519, for Authority to	)	NOTICE TO CUSTOMERS
Increase Rates for Water and Wastewater	)	
Utility Service in Woodlake in Moore	)	
County, North Carolina	)	

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Heater Utilities, Inc. to charge increased rates for water and wastewater service to all of its customers in Woodlake located in Moore County, North Carolina. The new approved rates are as follows:

Meter Size	Water Base Charge	Wastewater Base Charge
<1"	$ 12.11	$ 25.74
1"	30.29	64.35
1.5"	60.57	128.70
2"	96.91	205.92
3"	181.71	386.10
4"	302.86	643.50
6"	605.71	1,287.00
Commodity Charge$ (per 1,000 gallons)	3.51	$ 5.30

The new rates will increase the average monthly residential water bill from $17.12 to $26.36, based on an average month usage of 4,060 gallons and the average monthly wastewater bill from $19.67 to $46.06, based on an average monthly usage of 3,834 gallons.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of June, 2001.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

WATER AND SEWER - RATES

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-274, Sub 318, and the Notice was mailed or hand delivered by the date specified in the Order.

This the _____ day of _________________, 2001.

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-274, Sub 318.

Witness my hand and notarial seal, this the _____ day of _________________, 2001.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________________
Date

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WATER AND SEWER

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Duke Power, a Division of Duke Energy Corporation - Order Approving Experimental Program and Issuing Certificate of Public Convenience and Necessity
E-7, SUB 692 (07/25/2001)

North Carolina Municipal Power Agency Number 1 - Order Extending Certificate of Public Convenience and Necessity
E-43, SUB 2 (01/11/2001) Order Amending Certificate of Public Convenience and Necessity (05/31/2001)

NC Eastern Municipal Power Agency - Order Extending Certificate of Public Convenience and Necessity
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Carolina Power & Light Company - Order Issuing Certificate of Environmental Compatibility
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Carolina Power & Light Company - Order Approving Reallocation of Decommissioning Fund Contributions
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Carolina Power & Light Company - Order Granting Joint Motion and Closing Docket
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Dominion North Carolina Power; Virginia Electric & Power Co., dba - Order Closing Docket
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Duke Power, a Division of Duke Energy Corporation - Order Approving Revision to Option C
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Carolina Power & Light Company - Order Approving Revised Lighting Service Schedules
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Carolina Power & Light Company - Order Approving Revision
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Dominion North Carolina Power; Virginia Electric & Power Co., dba - Order Discontinuing Reporting Requirement
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Duke Power, a Division of Duke Energy Corporation - Order Revising Outdoor Lighting Schedule OL
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Carolina Power & Light Company - Order Granting Authority to Issue and Sell Securities
E-2, SUB 783 (05/24/2001)

Duke Power, a Division of Duke Energy Corporation - Order Granting Authority To Issue And Sell Securities
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Duke Power, a Division of Duke Energy Corporation - Order Granting Authority to Issue and Sell Securities
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Rockingham Power, LLC - Order Regarding Docket Number
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Rowan Generating Company, LLC - Order Issuing Certificate and Waiving Public Notice and Hearing
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Municipal Gas Authority of Georgia/City of Toccoa, Georgia - Order Authorizing Purchased Gas Adjustment Procedures
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G-21, SUB 408 (01/31/2001)

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Piedmont Natural Gas Company, Inc. - Order Allowing Rate Changes Effective October 1, 2001
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G-5, SUB 423 (08/29/2001)

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G-5, SUB 425 (11/01/2001)

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North Carolina Natural Gas Corporation - Order Allowing Interim Agreement to Become Effective
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Piedmont Natural Gas Company, Inc. - Order Allowing Contract to Become Effective
G-9, SUB 443 (06/19/2001)

Piedmont Natural Gas Company, Inc. - Order Approving Contract of Gas Service Agreement with Public Service Company of North Carolina, Inc.
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North Carolina Natural Gas Corporation - Order Closing Docket Concerning Application for Approval to Use Natural Gas Bond Funds for the Extension of Natural Gas Service in Troy in Montgomery County
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Eastern North Carolina Natural Gas Company - Order Granting Application for Waiver
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Piedmont Natural Gas Company, Inc. - Order Approving Program
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Public Service Company of N.C., Inc. - Order Amending Statistical Sampling Program
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Municipal Gas Authority of Georgia/City of Toccoa, Georgia - Order Allowing Rate Changes Effective July 16, 2001
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NUI North Carolina Gas - Order Closing Docket Concerning Application for Approval of Exchange of Shares with NUI Holding Company
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Piedmont Natural Gas Company, Inc. - Order Granting Authority to Issue and Sell Securities
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Public Service Company of N.C., Inc. - Order Closing Dockets
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NON REGULATED AUTHORITY - Certificate

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TELEPHONE - Cancellation of Certificate

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ATCALL, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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Broadband Office Communications, Inc. - Order Canceling Certificates
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Broadplex, LLC - Order Affirming Previous Commission Order Canceling Certificate
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BroadStream Corporation - Order Cancelling Certificates
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Broadstreet Communications, Inc. - Order Canceling Certificates
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Buyers United International, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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CallManage, Inc. - Order Canceling Certificate
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Cam-Comm, Inc. - Order Canceling Certificate
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Camanco Communications - Order Affirming Previous Commission Order Canceling Certificate
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Colorado River Communications Corp.- Order Affirming Previous Commission Order Canceling Certificate
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ConnectAmerica, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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CTN Telephone Network, Inc. - Order Canceling Certificate
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Digital Broadband Communications, Inc. - Order Canceling Certificate
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Discount Call Rating, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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Discount Network Services, Inc. - Order Canceling Reseller Certificate
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Efficy Group, Inc. - Order Canceling Certificate
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Empire Communications, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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Equality, Inc. - Order Canceling Certificate
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FirstWorld Communications, Inc. - Order Canceling Reseller Certificate
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Freedom Telecom Corp. - Order Affirming Previous Commission Order Canceling Certificate
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Fon Digital Network, Inc.- Order Affirming Previous Commission Order Canceling Certificate
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Global Telephone Corporation - Order Affirming Previous Commission Order Canceling Certificate
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GST Net, Inc. - Order Canceling Certificate
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IE Com - Order Affirming Previous Commission Order Canceling Certificate
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Inacom Communications, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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INET Interactive Network System - Order Affirming Previous Commission Order Canceling Certificate
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Intelicom International Corp. - Order Affirming Previous Commission Order Canceling Certificate
P-405, SUB 3 (03/21/2001)

JATO Operating Two Corp. - Order Affirming Previous Commission Order Canceling Certificate
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LDM Systems, Inc. - Order Cancelling Certificates
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LightNetworks, Inc. - Order Canceling Local and Long Distance Certificates
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LightSource Telecom I, LLC - Order Canceling Certificate
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LineDrive Communications Inc. - Order Canceling Certificates
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Long Distance America, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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Long Distance Services, Inc.- Order Affirming Previous Commission Order Canceling Certificate
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Network Access Solutions Corporation - Order Canceling Certificates
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NorthPoint Communications, Inc. - Order Canceling Certificate
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NTI Telecom, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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OnSite Access Local, LLC - Order Canceling Certificates
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Pac-West Telecom, Inc. - Order Canceling Certificate
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Prism Operations, LLC - Order Canceling Certificates
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Quintelco, Inc. - Order Canceling Certificate
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Rhythms Links Inc. - Order Granting Petition
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Southwest Communications, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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Starlink Communications, LLC - Order Canceling Certificate
P-503, SUB 2 (10/31/2001)

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P-250, SUB 2 (03/21/2001)

Telicor, Inc.- Order Affirming Previous Commission Order Canceling Certificate
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Telscape USA, Inc. - Order Affirming Previous Commission Order Canceling Certificate
P-589, SUB 2 (10/30/2001)

Tin Can Communications, Inc. - Order Affirming Previous Commission Order Canceling Certificate
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P-940, SUB 1 (03/21/2001) Order Vacating Orders of January 21, 2001, and March 21, 2001, and Reinstating Operating Authority (08/28/2001)

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USA Global Link, Inc. - Order Canceling Certificate
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USBG, Inc.- Order Affirming Previous Commission Order Canceling Certificate
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Utility.com, Inc. - Order Canceling Reseller Certificate
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Verizon Advanced Data, Inc. - Order Allowing Abandonment of Service and Canceling Certificates
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VoCall Communications Corp. - Order Canceling Certificate
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2nd Century Communications, Inc. - Order Canceling Certificates
P-891, SUB 2 (07/27/2001)

360 Telephone Company of North Carolina - Order Canceling Certificate
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@Link Networks, Inc. - Order Canceling Local Certificate and Withdrawing Application for Long Distance Authority
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TELEPHONE - Cease and Desist

TALK.COM Holding Corporation - Order Approving Consent Agreement
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TALK.COM Holding Corporation - Order Vacating April 10, 2001, Order to Cease and Desist
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Aura Communications, Inc.	P-1088, SUB 0	(04/26/2001)
Cbeyond Communications, LLC	P-1044, SUB 1	(01/31/2001)
CityNet Telecom, Inc.	P-1094, SUB 1	(05/29/2001)
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Telicor, Inc.	P-1046, SUB 1	(03/19/2001)
VarTec Telecom, Inc.	P-362, SUB 6	(08/10/2001)
Victory Communications, Inc.	P-1084, SUB 0	(05/23/2001)
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DV2, Inc. - Order Concerning Dismissal of Application
P-953, SUB 1 (11/27/2001)

Enkido, Inc. - Recommended Order Granting Certificate of Public Convenience and Necessity
P-1063, SUB 0 (04/26/2001)

eVulkan, Inc. - Order Canceling Long Distance Certificate and Allowing Withdrawal of Local Service Application
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InFLow, Inc. - Recommended Order Granting Certificate of Public Convenience and Necessity
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P-1076, SUB 0 (08/03/2001)

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Spartan Communications Corporation of North Carolina - Order Dismissing Application without Prejudice and Closing Docket
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P-118, SUB 105 (01/26/2001)

ALLTEL Carolina, Inc. - Order Approving Resale Agreement with TeleConex, Inc.
P-118, SUB 106 (03/14/2001)

ALLTEL Carolina, Inc. - Order Approving Resale Agreement with Phone-Link, Inc.
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ALLTEL Carolina, Inc. - Order Approving Interconnection Agreement with Paramount Communications, Inc.
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ALLTEL Carolina, Inc. - Order Approving Interconnection Agreement with Broadslate Networks of North Carolina, Inc.
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ALLTEL Carolina, Inc. - Order Approving Interconnection Agreement with DukeNet Communications, Inc.
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ALLTEL Carolina, Inc. - Order Approving Interconnection Agreement with CAT Communications International, Inc.
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BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with ALLTEL Communications, Inc.
P-55, SUB 1049 (11/30/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with XO North Carolina, Inc.
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BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with XO North Carolina, Inc.
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BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with DIECA Communications Company
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BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with DIECA Communications Company
P-55, SUB 1123 (12/13/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Resale Agreement with Budget Phone, Inc.
P-55, SUB 1148 (02/21/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with NEXTEL South Corporation
P-55, SUB 1157 (11/30/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with OptiLink Communications, Inc.
P-55, SUB 1198 (12/13/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with The Other Phone Company, Inc.
P-55, SUB 1211 (04/05/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with The Other Phone Company, Inc.
P-55, SUB 1211 (11/30/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with Business Telecom, Inc.
P-55, SUB 1212 (02/21/2001)

BellSouth Telecommunications, Inc. - Order on Amendments to Interconnection Agreement with Business Telecom, Inc.
P-55, SUB 1212 (09/28/2001)

BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with Business Telecom, Inc.
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BellSouth Telecommunications, Inc. - Order on Amendment to Interconnection Agreement with Global Crossing Local Services, Inc. and Global Crossing Telemanagement, Inc.
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P-656, SUB 4 (08/09/2001)

Empire Communications, Inc. - Order Closing Docket in Complaint of Kimberly Calhoun, Howard Swartz, Robert Holmes, and Christopher Cedrone
P-804, SUB 2 (05/04/2001) Order Reopening Docket (06/13/2001)

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Thrifty Call, Inc. - Final Order Denying Exceptions and Affirming Recommended Order in Complaint of BellSouth Telecommunications, Inc.
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US LEC of North Carolina, Inc. - Order Closing Docket in Complaint of BellSouth Telecommunications, Inc.
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Carolina Telephone and Telegraph Company - Order Approving Extended Area Service - Spring Hope to Raleigh and Zebulon
P-7, SUB 959 (09/26/2001) Errata Order (10/03/2001)

Carolina Telephone and Telegraph Company - Order Approving Extended Area Service - Richlands to Trenton
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Central Telephone Company - Order Approving Extended Area Service - Badin Lake to Troy
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Direct One, Inc. - Recommended Order Dismissing Application with Prejudice and Canceling Hearing
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Actel Integrated Communications, Inc.	P-1089, SUB 0	(04/04/2001)
Advanced Tel, Inc.	P-1102, SUB 0	(04/27/2001)
America's Digital Satelite Telephone	P-1114, SUB 0	(07/05/2001)
American Farm Bureau, Inc.	P-1041, SUB 0	(11/27/2001)
A.R.C. Networks, Inc.	P-1105, SUB 0	(05/24/2001)
Available Telecom Services, Inc.	P-1087, SUB 0	(06/15/2001)
Ciera Network Systems, Inc.	P-879, SUB 0	(02/28/2001)
CityNet Telecom, Inc.	P-1094, SUB 0	(04/04/2001)
CityNet Telecom, Inc.	P-1094, SUB 1	(05/29/2001)
Custom Teleconnect, Inc.	P-1085, SUB 0	(04/04/2001)
Debit One Communications, Inc.	P-1109, SUB 0	(07/05/2001)
Frontier Communications of America, Inc.	P-1100, SUB 0	(06/19/2001)
Gates Communications, Inc.	P-1086, SUB 0	(02/28/2001)
Global Crest Communications, Inc.	P-1116, SUB 0	(07/03/2001)
Keen LD, Inc.	P-1123, SUB 0	(07/20/2001)
KMC Data, LLC	P-1126, SUB 1	(08/16/2001)
Legent Communications Corporation	P-1150, SUB 0	(11/26/2001)
LightSource Telecom I, LLC	P-1076, SUB 1	(02/20/2001)
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LPM MICRONICS, LLC	P-1128, SUB 0	(07/30/2001)
Metropolitan Telecomm. of North Carolina, Inc.	P-1104, SUB 0	(05/03/2001)
Nationnet Communications Corporation	P-1008, SUB 0	(07/25/2001)
New East Telephony, Inc.	P-718, SUB 2	(07/20/2001)
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TDI Communications, Inc.	P-1137, SUB 0	(09/21/2001)
TelecomEZ Corporation	P-1101, SUB 0	(04/27/2001)
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Telegenius, Inc.	P-1118, SUB 0	(07/06/2001)
TeleUno, Inc.	P-1078, SUB 0	(08/09/2001)
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Toledo Area Telecommunications Systems, Inc.	P-1082, SUB 0	(02/20/2001)
Uni-Tel Communications Group, Inc.	P-1034, SUB 0	(02/28/2001)
United Systems Access Telecom, Inc.	P-1153, SUB 0	(12/05/2001)
U.S. Payphone, Inc.	P-1060, SUB 0	(03/26/2001)
Viva Telecom, L. L. C.	P-1107, SUB 0	(07/11/2001)
Wilkes Long Distance, Inc.	P-1090, SUB 0	(03/22/2001)
World Communications Satellite Systems, Inc.	P-1119, SUB 0	(07/09/2001)
X2Comm, Inc.	P-1147, SUB 0	(10/09/2001)
1-800-RECONEX, Inc.	P-665, SUB 5	(06/08/2001)

AFN Telecom, LLC - Recommended Order Granting Certificate of Public Convenience and Necessity
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American Fiber Systems, Inc. - Recommended Order Granting a Certificate of Public Convenience and Necessity
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Carolina Broadband, Inc. - Recommended Order Granting a Certificate of Public Convenience and Necessity
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Carolina Broadband, Inc. - Order Closing Docket in Application for a Certificate of Public Convenience and Necessity to Provide Long Distance Service as a Reseller
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Sigma Networks Telecommunications, Inc. - Order Allowing Withdrawal and Cancellation
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BellSouth Telecommunications, Inc. - Order Concerning BellSouth's and Sprint's Monthly Service Objective Result Filings
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BellSouth Telecommunications, Inc. - Order Allowing Tariff and Reminding IXCs of Flow-Through Requirement
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BellSouth Telecommunications, Inc. - Order Closing Docket in Arbitration of Interconnection Agreement with Intermedia Communications, Inc.
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BellSouth Telecommunications, Inc. - Order Granting Reserved Numbers
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BellSouth Telecommunications, Inc. - Order Ruling on the BellSouth Petition
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ITC Deltacom Communications, Inc. - Order Approving Amendment
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North State Telephone Company - Order Ruling on Petition for Review of NANPA Denial of Application for Numbering Resources
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North State Telephone Company - Order Ruling on North State Petition
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Time Warner Telecom of North Carolina, L.P. - Order Approving Amendment of Interconnection Agreement with BellSouth Telecommunications, Inc.
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Verizon South Inc. - Order Allowing Certain Tariffs to Become Effective and Requesting Comments
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Verizon South Inc. - Order Closing Docket in Collocation Office Exemption Documentation
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erbia Network, Inc. - Recommended Order Denying Request for Reinstatement of Certificate and Imposing Penalty
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Concord Telephone Company - Order Granting Authority to Borrow Under Credit Agreement
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TELEPHONE - Tariff

AT&T Communications of the Southern States, LLC - Order Approving Tariff
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BellSouth Telecommunications, Inc. - Order Approving Promotion
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BellSouth Telecommunications, Inc. - Order Allowing Tariff Subject to Notice of Opt-Out
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Carolina Telephone and Telegraph Company - Order Allowing Tariffs to Become Effective Subject to Conditions
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TELEPHONE - Sale/Transfer

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P-705, SUB 1 (02/20/2001)

Americatel Corporation - Order Approving Transfer of Control
P-705, SUB 2 (10/10/2001)

AS Telecommunications, Inc. - Order Approving Discontinuance of Service and Transfer of Customers
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AT&T Communications of the Southern States, LLC - Order Approving Corporate Reorganization
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Bell Atlantic Communications, Inc. - Order Approving Transfer of Customers
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Business Telecom, Inc. - Order Approving Transfer of Control and Exemption from Securities Regulation
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Capsule Communications, Inc. - Order Approving Transfer of Control
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Capsule Communications, Inc. - Order Approving Transfer of Control
P-942, SUB 2 (10/10/2001)

Cash Back Rebates LD.com, Inc. - Order Approving Transfer of Control
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Comcast Business Communications, Inc. - Order Approving Transfer of Control
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CTC Long Distance Services, Inc. - Order Approving Merger and Certificate Transfer
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DSLnet Communications, LLC - Order Approving Transfer of Control
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E-Z Tel, Inc. - Order Approving Transfer of Control
P-656, SUB 5 (04/05/2001)

Enhanced Communications Network, Inc. - Order Approving Transfer of Control
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Enhanced Communications Network, Inc. - Order Approving Customer Transfer and Canceling Certificate
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I-Link Communications, Inc. - Order Approving Transfer of Control
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ICG Telecom Group, Inc. - Order Approving Transfer of Customers
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IDT America, Corp. - Order Approving Transfer of Control
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InFlow, Inc. - Order Approving Transfer of Control
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KMC Telecom II, Inc. - Order Approving Transfer of Customers
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LecStar Telecom, Inc. - Order Approving Transfer of Control
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LEXCOM Long Distance, LLC - Order Approving Merger and Certificate Transfer
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Max-Tel Communications, Inc. - Order Rescinding Order Approving Transfer of Control and Closing Dockets
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NewSouth Communications Corp. - Order Approving Transfer of Control
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Single Billing Services, Inc. - Order Approving Transfer of Control
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Williams Communications, LLC - Order Approving Corporate Restructuring
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Working Assets Funding Service, Inc. - Order Approving Transfer of Control
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1-800-RECONEX, INC. - Order Approving Transfer of Control
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SPECIAL CERTIFICATE/PSP - Cancellation of Certificate

A. Classic Touch; Shirley A. Hall, DBA - Order Canceling PSP Certificate
SC-1594, SUB 1 (03/13/2001)

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Ahn; Myoung Sun - Order Canceling PSP Certificate
SC-1457, SUB 1 (04/20/2001)

Bald Head Island, Limited - Order Canceling PSP Certificate
SC-708, SUB 2 (12/07/2001)

Botsch; Paul William - Order Canceling PSP Certificate
SC-1559, SUB 1 (02/06/2001)

Burns Communication Industries; James Lester Burns & James Lief Burns, dba - Order Canceling PSP Certificate
SC-1574, SUB 1 (05/16/2001)

Cannon; Mark - Order Canceling PSP Certificate
SC-1587, SUB 1 (09/04/2001)

Canton Management, Inc. - Order Canceling PSP Certificate
SC-1292, SUB 1 (08/16/2001)

CCC Enterprises; Sandra L. Carpenter, dba - Order Canceling PSP Certificate
SC-1235, SUB 1 (08/03/2001)

Cook; Dan B. - Order Canceling PSP Certificate
SC-1082, SUB 1 (04/20/2001)

Correctional Communications, Inc. - Order Canceling PSP Certificate
SC-1610, SUB 1 (03/19/2001)

CTC Public Phone Services; CTC Long Distance Services, Inc., dba - Order Canceling PSP Certificate
SC-1361, SUB 1 (10/24/2001)

Diamond Communications Services, Inc. - Order Affirming Previous Commission Order Canceling PSP Certificate
SC-945, SUB 3 (05/29/2001) Errata Order (06/12/2001)

DuBois; Charles - Order Canceling PSP Certificate
SC-1521, SUB 1 (10/19/2001)

Eastern Telephone Service - Order Canceling PSP Certificate
SC-699, SUB 1 (12/05/2001)

Famoun Subs and Pizza of New Bern, Inc. - Order Canceling Certificate
SC-1590, SUB 1 (01/04/2001)

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G&G; Carin G. Goodall-Gosnell, dba - Order Canceling PSP Certificate
SC-1535, SUB 2 (04/27/2001)

Gamon N.; Cecil L. - Order Canceling PSP Certificate
SC-1636, SUB 1 (12/03/2001)

Gragg; Robert - Order Canceling PSP Certificate
SC-1409, SUB 1 (04/20/2001)

Harlan; Kenneth and Gail - Order Canceling PSP Certificate
SC-1503, SUB 1 (12/05/2001)

Herndon; Joel - Order Canceling PSP Certificate
SC-1617, SUB 1 (06/05/2001)

Hix; Kyle Parker - Order Canceling PSP Certificate
SC-1616, SUB 1 (04/20/2001)

Interstate Coin Telephone Incorporated - Order Canceling PSP Certificate
SC-921, SUB 2 (02/22/2001)

JA & KE; Thomas L. Jacobs and Kevin Houston, dba - Order Canceling PSP Certificate
SC-1510, SUB 1 (11/19/2001)

Jevic Transportation, Inc. - Order Canceling PSP Certificate
SC-1138, SUB 1 (03/13/2001)

JJL Enterprises, Inc. - Order Canceling PSP Certificate
SC-1241, SUB 1 (03/09/2001)

Kernersville; Town of - Order Canceling PSP Certificate
SC-1123, SUB 1 (10/19/2001)

Kristin Kirk Properties, Inc. - Order Canceling PSP Certificate
SC-1399, SUB 1 (11/29/2001)

Lester; Terri - Order Canceling PSP Certificate
SC-1608, SUB 1 (03/22/2001)

Love Communications; Abraham Mengistu, dba - Order Canceling PSP Certificate
SC-1627, SUB 1 (07/24/2001)

Micron Communications; Darrell W. Beidleman, dba - Order Canceling PSP Certificate
SC-1543, SUB 1 (04/27/2001)

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Notae Group, Inc.; Notae, Inc., dba - Order Canceling PSP Certificate
SC-1085, SUB 1 (06/05/2001)

Payphone Management Systems, Inc. - Order Canceling PSP Certificate
SC-1187, SUB 1 (04/20/2001)

R & E Pay Phones; Randy Len Bullins, dba - Order Canceling PSP Certificate
SC-1530, SUB 1 (09/06/2001)

Shelton, Jr.; William M. - Order Canceling PSP Certificate
SC-1656, SUB 1 (11/02/2001)

Shook; Terry - Order Canceling PSP Certificate
SC-1647, SUB 1 (11/09/2001)

Southwest Pay Telephone Corporation - Order Canceling PSP Certificate
SC-1327, SUB 4 (04/23/2001)

Sowers; Michael O. - Order Canceling Certificate
SC-1555, SUB 1 (01/04/2001)

Summit Hospitality Group, Ltd. - Order Canceling PSP Certificate
SC-1625, SUB 1 (11/21/2001)

Swaney; Joyce - Order Canceling PSP Certificate
SC-1643, SUB 1 (09/21/2001)

Swicegood; J. Carr - Order Canceling PSP Certificate
SC-1385, SUB 2 (04/20/2001)

The Gin Mill Southend; Van Reypen Assoc., Inc., dba - Order Canceling PSP Certificate
SC-1455, SUB 1 (10/03/2001)

The Ocracoke Telephone Company; Sean Trainor, dba - Order Canceling PSP Certificate
SC-1284, SUB 4 (04/09/2001)

Tokyo Restaurant; Yoshihiko Shioda, dba - Order Canceling PSP Certificate
SC-442, SUB 1 (06/01/2001)

Total Communications Network; James Brewer dba - Order Canceling PSP Certificate
SC-1582, SUB 1 (07/03/2001)

Wilkie; Nancy - Order Canceling PSP Certificate
SC-1648, SUB 1 (11/02/2001)

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World Communications Network LLC - Order Canceling Certificate
SC-1507, SUB 1 (01/16/2001)

Yadkin Valley Telecom, Inc. - Order Canceling PSP Certificate
SC-1490, SUB 1 (08/17/2001)

Zmail Media, Inc. - Order Canceling PSP Certificate
SC-1619, SUB 1 (04/27/2001)

SPECIAL CERTIFICATE/PSP - Certificate Issued

Company	Docket No.	Date
American Bell Communications; Van Josheff, dba	SC-1657, SUB 0	(08/16/2001)
Anderson; Richard M	SC-1658, SUB 0	(08/16/2001)
Atlantic Public Telephone Corporation	SC-1623, SUB 0	(01/29/2001)
Bell, A General Partnership; Landon Runion & Zachary David	SC-1624, SUB 0	(02/14/2001)
Black; Judith M.	SC-1640, SUB 0	(05/08/2001)
Cabin Creek Campground & Mobile Home Park; Sharon Yankow, dba	SC-1652, SUB 0	(07/09/2001)
Call Communication, Inc.	SC-1642, SUB 0	(05/15/2001)
Cherokee Telephone Co. Inc.	SC-1630, SUB 0	(02/13/2001)
Cincinnati Bell Public Communications, Inc.	SC-1626, SUB 0	(02/01/2001)
Clark Telecommunications, Inc.	SC-1664, SUB 0	(10/08/2001)
Conversant Technologies, Inc.	SC-1622, SUB 0	(01/29/2001)
Crowder; Lisa L.	SC-1649, SUB 0	(06/25/2001)
CTC Long Distance Services, LLC; CTC Public Phone Services, dba	SC-1655, SUB 0	(07/18/2001)
Darnell; Wendy	SC-1631, SUB 0	(02/28/2001)
Discount Bail Bonds, Inc.	SC-1660, SUB 0	(09/06/2001)
Faith Chapel of Lexington, Inc.	SC-1645, SUB 0	(06/05/2001)
FRNKJD, Inc.	SC-1629, SUB 0	(02/09/2001)
Garmon, Cecil L.	SC-1636, SUB 0	(04/24/2001)
GCB Communications, Inc.	SC-1573, SUB 2	(02/22/2001)
Hayes; Sandra	SC-1668, SUB 0	(12/17/2001)
Haywood Regional Medical Center	SC-1666, SUB 0	(11/14/2001)
Holland; Tanner E.	SC-1639, SUB 0	(05/08/2001)
Hughes, Louis W.	SC-1665, SUB 0	(10/23/2001)
JellyBeans, LLC	SC-1661, SUB 0	(09/06/2001)
Knight's Lighting Inc.; Williams Communications, dba	SC-1663, SUB 0	(09/21/2001)

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Lev; Yehuda J. and Judith S.;		
J & J Communication Enterprises, dba	SC-1634, SUB 0	(04/10/2001)
Long; Darold E.	SC-1628, SUB 0	(02/09/2001)
Mackey, JR.; Charles	SC-1635, SUB 0	(04/24/2001)
MAH Communications/Utelecom, LLC	SC-1653, SUB 0	(07/17/2001)
McCanna; C. E.	SC-1637, SUB 0	(04/30/2001)
McDaniel; John E.	SC-1670, SUB 0	(12/19/2001)
Meeks; Dennis E.;		
Vending Tymes dba	SC-1654, SUB 0	(07/18/2001)
Mengistu; Abraham;		
Love Communications, dba	SC-1627, SUB 0	(02/22/2001)
National Telephone Company, L.L.C.	SC-1662, SUB 0	(09/06/2001)
Nguyen; Kim H.	SC-1646, SUB 0	(06/05/2001)
Powers; Larry W.	SC-1651, SUB 0	(06/29/2001)
Qwest Interprise America, Inc.	SC-1659, SUB 0	(08/30/2001)
RCR Properties, LLC	SC-1633, SUB 0	(05/02/2001)
Shelton, Jr.; William M.	SC-1656, SUB 0	(08/07/2001)
Shook; Terry	SC-1647, SUB 0	(06/18/2001)
Sings; Stephen; More Than One Son, dba	SC-1667, SUB 0	(12/07/2001)
Smith; Roderick C.;		
MMSEAS Communications, dba	SC-1638, SUB 0	(05/02/2001)
Spartan Ventures, Inc.	SC-1669, SUB 0	(12/17/2001)
Summit Hospitality Group, Ltd.	SC-1625, SUB 0	(01/30/2001)
Swaney; Joyce	SC-1643, SUB 0	(05/31/2001)
Sword; George P.;		
Ord-Mark Communications, dba	SC-1621, SUB 0	(01/04/2001)
TCG Public Communications, Inc.	SC-1632, SUB 0	(03/14/2001)
Tokyo Company, Inc.	SC-1644, SUB 0	(05/31/2001)
Tucker; James	SC-1650, SUB 0	(06/29/2001)
Wilkie; Nancy	SC-1648, SUB 0	(06/18/2001)
Williams; E. L.	SC-1641, SUB 0	(05/15/2001)

SPECIAL CERTIFICATE/PSP - Miscellaneous

McFadden Communications; Brian McFadden, dba - Order Reissuing PSP Certificate
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Meeks; Dennis E.; Vending Tymes, dba - Order Reissuing PSP Certificate
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Lexcom Telephone; Lexington Telephone Company, dba - Order Reissuing Special Certificate Due to Name Change
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Rockingham Power, LLC - Order on Request for Approval of Contract Provision
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TRANSPORTATION - Common Carrier Certificate

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Cadillac Moving Services; Cadillac Transport Services, Inc., dba - Order Granting Common Carrier Authority
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I Will Move It Today; Vannell Robinson, dba - Order Dismissing Application and Closing Docket
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McLaughlin; Gregory L.; Minute Man Movers, dba - Order Allowing Withdrawal of Application
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Portable Storage Systems, Inc.; dba PODS - Order Granting Temporary Authority
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Sam's Pickup and Delivery, Inc. - Order Granting Common Carrier Authority
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Toby M. Brown Transportation; Toby M. Brown ,dba - Order Granting Common Carrier Authority
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Action Moving and Storage of North Carolina, Inc. - Order Vacating Orders of July 24, 2000, and September 11, 2000, and Reinstating Operating Authority
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All About Moving, Inc. - Order Affirming Previous Commission Order Cancelling Operating Authority
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Brodie's Moving Service, Ltd - Order Affirming Previous Commission Order Cancelling Operating Authority
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Charwill, Inc. - Order Affirming Previous Commission Order Cancelling Operating Authority
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Ezzell Trucking Inc. - Order Affirming Previous Commission Order Cancelling Operating Authority
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J. C. Wooldridge, Inc. - Order Cancelling Common Carrier Certificate
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North American Van Lines, Inc. - Order Vacating Orders of July 24, 2000, and September 22, 2000, and Reinstating Operating Authority
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Sam's Pickup and Delivery, Inc. - Order Affirming Previous Commission Order Cancelling Authority
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Tar Heel Reliable Movers, Inc. - Order Affirming Previous Commission Order Cancelling Operating Authority
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Triple Am Moving& Storage Inc. - Order Affirming Previous Commission Order Cancelling Operating Authority
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American Moving Systems, Inc. - Order Approving Name Change
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Home Moving Systems, Inc. - Order Approving Name Change
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Sandhills Moving & Storage Co. - Order Approving Name Change
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Smoky Mountain Moving Co., Inc. - Order Approving Name Change
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TROSA Moving; Trosa, Inc., dba - Order Approving Name Change
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Ace Moving & Storage Co.; Century Transport Systems, Inc., dba - Order Affirming Previous Commission Order Cancelling Operating Authority
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Moving Store, Inc.; The - Order Affirming Previous Commission Order Cancelling Operating Authority
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Rates-Truck - Order Allowing Fuel Surcharge
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A & A Moving; Pitt Movers, Inc. dba - Recommended Order Cancelling Operating Authority
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AAA Moving; Phillip Paul Latham, dba - Recommended Order Cancelling Operating Authority
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Advance Moving and Storage; Linda Bunch, dba - Order Approving Name Change and Dismissing Show Cause
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American Delivery Services, Inc. - Recommended Order Cancelling Temporary Operating Authority
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Benelux Moving Company; Masoud Mansouri, dba - Recommended Order Cancelling Operating Authority
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Campbell's Transfer & Storage; Tommy Campbell, dba - Recommended Order Cancelling Operating Authority
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Carolina Moving & Storage Co. - Recommended Order Cancelling Operating Authority
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Martin Transfer and Storage Co. - Recommended Order Cancelling Operating Authority
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Terminal Storage Company, Inc. - Recommended Order Cancelling Operating Authority
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Tri-City Moving & Storage, Inc. - Recommended Order Cancelling Operating Authority
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Tryon Moving & Storage, Inc. - Order Cancelling Hearing and Closing Docket
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DunMar Movers Charlotte; Brown-Thomas Corporation, dba - Order Granting Authorized Suspension
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Jiffy Moving & Storage Company; W.M. Poole Enterprises, Inc., dba - Order Granting Authorized Suspension
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R.M. Williams Moving Service; Richard Marvin Hawkins, Jr., dba - Order Granting Authorized Suspension
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Anthony Moving & Storage Company - Order Approving Sale and Transfer
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Berger Charlotte, Inc. - Order Approving Transfer and Name Change
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First Choice Moving & Storage, Inc. - Order Approving Transfer
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Hall's Transfer; Barry Scott Byrd, dba - Order Approving Sale and Transfer
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Hughes Logistics Corporation , Inc. - Order Approving Sale and Transfer
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Two Men and A Truck/Charlotte/Durham; Roeder & Moore, LLC, dba - Order Approving Sale and Transfer and Name Change
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WATER/SEWER - Abandonment

Rayco Utilities, Inc. - Order Closing Docket Concerning Unauthorized Abandonment of a Portion of its Franchise in Graystone Forest Subdivision in Forsyth County, North Carolina
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Carolina Water Service, Inc. of North Carolina - Order Granting Franchise and Approving Rates
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Earth Environmental Services; Michael Joel Ladd, dba - Order Granting Certificate, Approving Schedule of Rates and Requiring Public Notice
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Ginguite Woods Water Reclamation Association, Inc. - Recommended Order Requiring Bond and Approving Contracts
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Heater Utilities, Inc. - Order Recognizing Contiguous Extension and Approving Rates
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Heater Utilities, Inc. - Order Granting Franchise and Approving Rates
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Heater Utilities, Inc. - Order Approving Contract for the Provision of Bulk Sewer Service
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Heater Utilities, Inc. - Order Approving Contract for the Provision of Bulk Sewer Service
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Carolina Water Service, Inc. of North Carolina - Order Closing Docket in Complaint of Tony S. Auten
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Carolina Water Service, Inc. of North Carolina - Order Closing Docket in Complaint of Residents of Whitehart Subdivision
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Carolina Water Service, Inc. of North Carolina - Recommended Order in Complaint of G & W Partnership
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Carolina Water Service, Inc. of North Carolina - Recommended Order Ruling on Complaint of A. Ward Grant, Jr.
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Carolina Water Service, Inc. of North Carolina - Order Dismissing Complaint of Anthony A. Greco
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Heater Utilities, Inc. - Recommended Order Requiring Improvements in Complaint of Residents of A Country Place Subdivision
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Hydraulics, Ltd. - Order Dismissing Complaint of Karen McAtee and Closing Docket
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Hydraulics, Ltd. - Order Approving Joint Stipulation and Merger
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Tobacco Branch Village Water System, Inc. - Order Approving Name Change
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LaGrange Waterworks Corporation - Order Allowing Recommended Order to Become Effective and Final
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Mountain Ridge Estates Water System - Recommended Order Approving Rate Increase Subject to True Up
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Centerline Construction & Utilities, Inc. - Recommended Order Denying Application and Closing Docket
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Heater Utilities, Inc. - Order Approving Transfer, Canceling Franchise, Releasing Bond, and Requiring Customer Notice
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Heater Utilities, Inc. - Recommended Order Approving Rates
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Heater Utilities, Inc. - Order Approving Transfers and Rates and Requiring Customer Notice
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Total Environmental Solutions, Inc. - Order Approving Bond and Surety and Granting Transfer
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