EIGHTY-FIRST REPORT
of the
NORTH CAROLINA UTILITIES COMMISSION

ORDERS AND DECISIONS

Issued from

January 1, 1991, through December 31, 1991

William W. Redman, Jr., Chairman

Sarah Lindsay Tate, Commissioner

Julius A. Wright, Commissioner

Robert O. Wells, Commissioner

Charles H. Hughes, Commissioner

Laurence A. Cobb, Commissioner

* Allyson K. Duncan, Commissioner

North Carolina Utilities Commission
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The Statistical and Analytical Report of the North Carolina Utilities Commission is printed separately from the volume of Orders and Decisions and will be available from the Office of the Chief Clerk of the North Carolina Utilities Commission upon order.

Compiled and Edited By Donna Bayless

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* Appointed July 1, 1991, replacing Ruth E. Cook

LETTER OF TRANSMITTAL

December 31, 1991

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, 1991, we hereby present for your consideration the report of the Commission's decisions for the 12-month period beginning January 1, 1991, and ending December 31, 1991.

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

William W. Redman, Jr., Chairman

Sarah Lindsay Tate, Commissioner

Julius A. Wright, Commissioner

Robert O. Wells, Commissioner

Charles H. Hughes, Commissioner

Laurence A. Cobb, Commissioner

Allyson K. Duncan, Commissioner

Geneva S. Thigpen, Chief Clerk

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of the
North Carolina Utilities Commission

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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 OF CLARIFICATION AND MODIFICATION

BY THE COMMISSION: On September 14, 1990, the Commission issued its Further Order Establishing Procedures Related to Taxes on Contributions In Aid of Construction. On October 23, 1990, the Commission issued Order of Clarification that stated that the September 14, 1990, Order should apply to all CIAC, including that related to plant expansions into contiguous areas by water and sewer companies.

The Commission has carefully reviewed the Order of September 14, 1990, and concludes that some modification and clarifications should be made. The most significant modification to the September 14, 1990, Order that is being made herein is that the requirements of said Order should apply to contributions in aid of construction (CIAC) resulting from contracts signed after October 15, 1990. Therefore, said contracts signed between and including February 3, 1987, and October 15, 1990, must follow the guidelines established in the Commission's Order of August 26, 1987. In summary, all CIAC related to contracts signed after October 15, 1990, are subject to the above noted modification and the following requirements included in the following ordering paragraphs of the September 14, 1990, Order:

"1. That all water and sewer companies, in accordance with the guidelines set forth in this Order, shall use either the full gross-up or present value gross-up method with respect to all collections of CIAC.

2. That all water and sewer companies shall value CIAC for tax purposes at the greater of (1) original cost less a reasonable allowance for depreciation, (2) fair market value as defined herein, or (3) any other valuation technique the Company may wish to employ.

3. That the requirements set forth in the Commission's Order of January 26, 1988, to the extent that such requirements are inconsistent with the provisions of this Order, shall be and hereby are rescinded."

The Commission notes that all CIAC received is subject to the applicable guidelines, regardless of whether it is in the form of cash or non-cash assets.

The Commission further notes that the annual reports required to be filed by the water and sewer companies includes information on CIAC and related taxes received. The Commission will carefully review these reports for this information to make sure that the Commission's CIAC gross-up requirements are being strictly followed.

In earlier orders on this matter, the Commission has expressed deep concern with the valuation problems associated with CIAC for tax purposes. In order to fairly address these valuation problems, the Commission adopted the guidelines expressed in the September 14, 1990, Order on this matter. As stated above, the

Commission has concluded that all water and sewer companies should value CIAC for tax purposes at the greater of (1) original cost less a reasonable allowance for depreciation, (2) fair market value as defined in the September 14, 1990, Order, or (3) any other valuation technique the Company may wish to employ. These valuation guidelines were established in response to the Tax Reform Act of 1986. However, it should be made clear that the Internal Revenue Service, and, if need be, applicable courts will be the ultimate decider on valuation issues related to CIAC under the Tax Reform Act of 1986.

The September 14, 1990, Order requires that future tax benefits derived from depreciation on taxable CIAC, by companies applying the full gross-up method, should be flowed through to the utility's customers as a reduction to the cost of service. Requests to refund said benefits directly to the contributor shall be reviewed on a case by case basis.

IT IS, THEREFORE, ORDERED that the requirements of the Order of September 14, 1990, be, and hereby are, modified and clarified as noted herein this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 6th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

DOCKET NO. M-100, SUB 121

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of the Carriers of Unmanufactured Tobacco Participating in Tariff 8-Z, NCUC No. 168, North Carolina Trucking Association, Inc., Agent, P.O. Box 2977, Raleigh, North Carolina 27602	) ORDER RESCINDING) RULE R2-16.1 AND) ESTABLISHING FUEL) SURCHARGE PROCEDURES

BY THE COMMISSION: On September 11, 1990, the Commission issued an Order in this docket suspending the portions of NCUC Rule R2-16.1 pertaining to tobacco carriers. The tobacco carriers and their tariff publishing agent were allowed to utilize the procedure set forth in Exhibit A attached to said Order to adjust the fuel surcharge on a weekly basis, tracking changes in the Interstate Commerce Commission diesel price pending further order of the Commission.

The Order also initiated a rulemaking proceeding to rescind NCUC Rule R2-16.1 and to determine whether a new fuel surcharge rule should be implemented in its place. Such Order provided that any parties desiring to file comments and/or other proposed amendments to NCUC Rule R2-16.1 should do so on or before November 1, 1990.

Comments and proposed procedures for modifying fuel-related increases have been filed by the tobacco carriers; the bulk commodity carriers participating in Asphalt Tariff No. 16-K, NCUC 157, Bulk Tariff No. 21-J, NCUC 163, and Petroleum Tariff No. 5-W, NCUC 166; North Carolina Trucking Association, Inc., Agent (general commodities carriers); the North Carolina Movers Association, Inc. (household goods carriers); and the Southern Motor Carriers Rate Conference, Inc. (general commodities carriers).

The comments filed in this docket indicate that all parties agree that NCUC Rule R2-16.1 does not adequately deal with periods of rapid fuel price fluctuation and that such rule should be replaced. Also, all of the parties suggest that a surcharge be indexed in some manner to the actual cost of fuel and subject to adjustment on a weekly basis on the motion of a carrier, an affected shipper, the Public Staff or the Attorney General.

The tobacco carriers have proposed that the applicable cost of fuel should be determined by using the Interstate Commerce Commission's Pump Price Index. The general commodities carriers have proposed that the applicable cost of fuel should be based on the weighted actual price paid for fuel purchased in bulk quantities for use at terminals located throughout the state. The bulk commodity carriers have proposed that the applicable cost of fuel should be determined by using the average rack price for North Carolina terminals according to the list published by the Oil Price Information Service.

It is apparent from the comments filed in this docket that the carriers participating in different tariffs tend to have different operating characteristics which would tend to make a single fuel price index or formula for surcharges inappropriate. In this regard, the Public Staff in its comments suggested that rather than adopting a new rule in place of Rule R2-16.1, the Commission should issue guidelines for tariff riders which the carriers could adopt at their option. The Public Staff further suggested that the guidelines should establish procedural uniformity while recognizing the particular needs of the various carriers.

Based upon the foregoing, the Commission concludes that to adopt a single rule for all carriers which have different operating characteristics and different relationships between the cost of fuel and required surcharges would be inappropriate. Accordingly, the Commission concludes that it is appropriate at this time to adopt guidelines which establish procedural uniformity and recognize the particular operating characteristics of the various carriers. The guidelines for application for a fuel surcharge are as set forth in Appendix A attached to this Order.

The tobacco carriers and bulk commodity carriers also proposed that if fuel prices stabilize, the Commission should allow any existing fuel surcharge to be rolled into base rates. The Public Staff in its comments states that rate changes produced by these tariff riders are legal, in the absence of general rate cases, only because they are by their terms temporary. Accordingly, the Public Staff objects to any permanent "roll-in" of the increases outside the context of a general rate case.

The Commission has carefully considered this matter and concludes that the carriers should not be allowed to "roll-in" a fuel surcharge outside the context of a general rate case proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That Commission Rule R2-16.1 is hereby rescinded.

2. That a fuel surcharge procedure for motor carriers as set forth in Appendix A attached hereto and made a part hereof is hereby adopted and shall be in effect until rescinded or modified by the Commission.

3. That the index prices and surcharge schedules filed in this docket by the unmanufactured tobacco carriers, general commodities carriers, and bulk commodity carriers are hereby approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of January 1991.

NORTH CAROLINA UTILITIES COMMISSION
Sandra J. Webster, Chief Clerk

(SEAL)

APPENDIX A

The following temporary fuel surcharge procedure is adopted and shall be in effect until rescinded or modified by the Commission:

a. Any common carrier or authorized tariff publishing agent may apply pursuant to NCUC Rule R4-4 for approval of a fuel surcharge.

b. The application shall specify an independent and verifiable historical index price and shall include a schedule indicating the amount of surcharge to be imposed for each value or range of values of the index price. Subject to paragraph (c) below, the application may specify an index or schedule or both previously approved for a different carrier or group of carriers.

c. The application shall specify the initial value of the index price and shall include workpapers showing that the relationship between the requested index price and schedule of surcharge amounts reflects the operating characteristics of the applicant or applicants.

d. Initial applications for fuel a surcharge if filed no later than Thursday, shall be considered at the Commission's staff conference on the following Monday. If approved by the Commission on Monday, the surcharge may be placed into effect on the following Wednesday.

e. Applications or petitions for changes in the effective value of the index price may be filed by a carrier or carriers, the Public Staff, the Attorney General or any affected shipper. If such application or petition is filed no later than Thursday, it shall be considered at the Commission's staff conference on the following Monday. If approved by the Commission on Monday, the change in the amount of surcharge may be placed into effect on the following Wednesday.

f. Copies of applications for a surcharge and for changes in the effective value of the index price shall be served upon the Public Staff, the Attorney General, and any party requesting a copy. Persons desiring a copy who notify the Chief Clerk of the Commission in writing will be placed on a service list.

DOCKET NO. M-100, SUB 122

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Nantahala Power and Light Company to Adjust its Rates and Charges to Reflect Increases in State Income and Sales and Use Tax Expense and the Imposition of Regulatory Fees and/or for Institution of a Rulemaking Docket	ORDER DENYING APPLICATION FOR RATE ADJUSTMENT AND/OR FOR INSTITUTION OF A RULEMAKING INVESTIGATION

BY THE COMMISSION: On August 6, 1991, Nantahala Power and Light Company (Nantahala) filed an application pursuant to G.S. 62-23, 62-30, 62-31, State ex rel. Utilities Commission v. Edmisten, 294 N.C. 598, 242 S.E.2d 862 (1978), and State ex rel. Utilities Commission v. Nantahala Power and Light Co., 326 N.C. 190, 388 S.E.2d 118 (1990), for an adjustment in its rates and charges to reflect an increase in state income and sales and use tax expense and the imposition of a regulatory fee. In support of its application, Nantahala stated that on July 13, 1991, the North Carolina General Assembly enacted legislation that provided for an increase in the North Carolina corporate income tax rate from 7% to 7.75%. 1991 Session Laws, c. 689, s. 257. Additionally, the legislation creates a corporate income tax surcharge equal to a percentage of the corporate income tax payable in the tax year. The percentage rates of the surtax are 4% for 1991, 3% for 1992, 2% for 1993 and 1% for 1994. 1991 Session Laws, c. 689, s. 257. Also, the legislation increases the general rate of sales and use tax payable by North Carolina vendors from 3% to 4%. 1991 Session Laws, c. 689, s. 311.

Nantahala seeks permission to adjust its rates and charges to recover these increased income and sales and use tax expenses. The increase in the corporate income tax rate and addition of the surcharge is effective for taxable years beginning on or after January 1, 1991. 1991 Session Laws, c. 689, s. 357. The increase in the sales and use tax rate went into effect on July 16, 1991. 1991 Session Laws, c. 689, s. 357. Nantahala requests permission to begin to collect the increased tax expense immediately on an interim basis pending final action on Nantahala's request. Nantahala filed an undertaking to refund with interest such portion of the requested interim increase that the Commission subsequently determines to be excessive. According to Nantahala, failure to increase rates to recover the increased tax expense now being incurred will cause Nantahala a permanent loss of revenue to which it is entitled and result in a windfall to ratepayers at the shareholder's expense.

Nantahala further states that its rates were last adjusted in a general rate case proceeding in 1983 in Docket No. E-13, Sub 44, based upon a 1981 test year. In October and November 1987, in Docket No. M-100, Sub 113, the Commission decreased Nantahala's rates to reflect a reduction in the federal corporate income tax rate arising from the Tax Reform Act of 1986 (TRA-86). This reduction was partially offset by a change in North Carolina law brought about by House Bill 1155 passed by the 1987 General Assembly that increased the state income tax rate and made minor changes in the sales and use tax laws which also increased costs to the Company. Nantahala states that the Commission adjusted rates for Nantahala and many of the State's other utilities in the generic proceeding, Docket No. M-100, Sub 113, on the theory that a reduction in income tax expense would result in a windfall to stockholders if no adjustment to utility rates was made. Nantahala also states that it, as well as many other utilities, resisted the Docket No. M-100, Sub 113, rate reduction on a number of grounds, all of which were rejected by the Commission.

Nantahala appealed the Commission's Orders in Docket No. M-100, Sub 113, as applied to Nantahala. These Orders were ultimately upheld by the North Carolina Supreme Court in the Nantahala case, Id., decided by the North Carolina Supreme Court on February 7, 1990. According to Nantahala, the same theories, legal authority and precedent relied upon by the Commission and the North Carolina Supreme Court to support the decrease in rates in 1987 to pass through an income tax rate reduction should now support an increase in rates to pass through an increase in the income and sales and use tax rate.

In order to calculate the rate adjustment that results from the increase in the State income and sales and use tax rates, Nantahala states that it followed the same procedure followed by the Commission in Docket No. M-100, Sub 113. Nantahala indicates that it took the schedule used to make the tax calculation in Nantahala's last rate case, Docket No. E-13, Sub 44, as adjusted in Docket No.M-100, Sub 113, and made pro forma adjustments to reflect the change in State income and sales and use tax rates. In order to calculate the sales and use tax adjustment, Nantahala states that it calculated the amount of use tax now incorporated in present rates from Form E-1, filed in Docket No. E-13, Sub 44, established at a total rate of 4% and adjusted that amount to reflect the new 6% total (state and county) rate.

Because the Commission adjusted Nantahala's rates without hearing in Docket No. M-100, Sub 113, Nantahala requests that the same procedure be followed in this case.

Nantahala states that its immediate concern with respect to the increase in State taxes is limited to the impact upon Nantahala. However, a primary justification for the rate adjustment in Docket No. M-100, Sub 113, was that the rate adjustment was made in a rulemaking proceeding. To the extent that the Commission finds it necessary to establish a rulemaking proceeding in order to grant the relief Nantahala seeks, Nantahala requests that the Commission take such action. Nantahala states that since July 1, 1989, it has been paying a regulatory fee pursuant to G.S. 62-302. This fee is charged across-the-board to all the State's utilities based upon a percentage of revenues. Although Nantahala states that this fee is not a tax, the Company takes the position that its effect upon the Company is the same as that of a tax. Both expenses are functions of revenues Nantahala receives; both were imposed upon Nantahala by legislative action; and both are intended to provide funds for operations of State government. Nantahala's current rates based upon a 1981 test year were not designed to recover the regulatory fee. Because the sunset provision has been repealed and the fee is permanent, Nantahala requests rate recovery at this time.

Because the surcharge will cause the State corporate income tax rate to change again in 1992, 1993, and 1994, Nantahala requests that the Commission's Order in this docket acknowledge that adjustments will be necessary for future years to reflect the subsequent changes. Nantahala submitted as Exhibit 1 calculations which show the effect of these changes on rates for all the years. Attached as Exhibit 2 was a new Rate Schedule T, Tax Adjustment Rider which the Company would implement for bills rendered after August 2, 1991, which reflect the 1991 changes only. New rate schedules and/or a rider will be filed at the appropriate time to reflect the 1992 and later changes. Each Nantahala rate schedule will be revised to include a Schedule T.

According to Nantahala, its current overall rate of return is in the 6% to 7% range. The Company further states that the requested rate adjustments will not increase Nantahala's earned rate of return anywhere close to the authorized 12.52% rate of return or to any reasonable rate of return that would be awarded based upon current economic conditions.

On August 30, 1991, the Public Staff filed a response to Nantahala's application. By its response, the Public Staff recommends that Nantahala only be allowed to increase its rates to reflect the increase in the State income tax rate and that the Company's request for rate relief related to the regulatory fee and sales tax changes should be denied.

The Public Staff states that the effect of these changes will vary greatly from utility to utility. In view of the number of utilities who are either now in for rate cases or who already have the regulatory fee in rates, the Public Staff does not believe that the Commission should make all utilities, or even the largest 50 or so, parties to a proceeding in which they may not be interested. The Public Staff instead believes the Commission should set basic guidelines and then allow utilities to apply or not apply for rate changes as they wish. The Public Staff notes that a similar procedure was used when the VOC water testing requirements were imposed in Docket No. M-100, Sub 120.

As for the Company's request, the Public Staff agrees with only part of it. According to the Public Staff, the North Carolina Supreme Court has recognized only four ways rates can be changed. The first is pursuant to a specific, limited statute like the fuel clause, G.S. 62-133.2. Such a statute is not involved here. The second way is through a general rate case. The third is through a complaint case. The Company has filed for neither here, so the Public Staff does not discuss those alternatives. The last mechanism is through a rulemaking under G.S. 62-31. The Public Staff states that in the Nantahala case, the Commission reduced utility rates across-the-board to flow the benefits of the Tax Reform Act of 1986 through to customers. The Court identified three key elements that "made it appropriate for the Commission to use a rulemaking procedure" to change rates. These elements were: "(1) the tax reduction affected all utilities uniformly; (2) a large number of utilities were affected, making individual hearings for all inappropriate; and (3) no adjudicative-type facts were in dispute so as to require a trial-type hearing for each individual utility." 326 N.C. at 203.

According to the Public Staff, the income tax increase clearly falls within this procedure. Just as in Nantahala, the State income tax cost in the Company's last rate case is simply a "fall-out" calculation. It is not an expense item derived from an actual expense level. The Public Staff disagrees with the Company's calculations as shown in the exhibits attached to the application. The Company should be allowed to increase its rates and charges by only .0088¢/kWh to collect the additional revenues needed to cover the new tax liability.

The Public Staff, however, disagrees that either the regulatory fee or the sales tax increase can be added to present rates in a rulemaking procedure. Looking again at the three Nantahala elements, the Public Staff asserts that at least two of them are not met in either case. First, neither the fee nor the sales tax changes will affect all utilities uniformly. The fee will vary from year to year depending on the amount of jurisdictional revenues collected during the year and the rate of the fee set by the General Assembly. Because it is based on what the utility will actually pay, it is simply a regulatory expense dependent on several adjudicative facts. While many utilities presently have the fee included in their rates, most at the 0.12% figure, many others, including the Company, do not. The Public Staff states that if the Commission decides to adjust rates for the fee, it may not only have to add the fee to the rates of some, like the Company, but to reduce it for those whose rates include the old, higher fee. In that respect, the Public Staff asserts that the Commission should consider that under G.S. 62-302(b)(2) the fee is set each fiscal year. To embark on a policy to adjust rates for the fee here may mean embarking annually for similar changes. The Commission should contrast potential annual fee settings with the relatively infrequent changes in income taxes. The Public Staff questions whether the impact of the fee is so significant that the Commission would want to establish a policy of changing rates for it year after year. Likewise, the Public Staff states that the sales tax change does not fit Nantahala's first element. It is an expense item based on test year purchases. Just as in the case of the regulatory fee, it will vary from year to year. The total sales tax paid will change every year depending on what things are bought, how many are bought, and what their prices are.

Therefore, the Public Staff asserts that the first element of Nantahala is not met, because the fee and the sales tax changes do not affect all utilities uniformly.

The Public Staff also takes the position that the third Nantahala element, the requirement that no adjudicative facts be in issue, is also lacking here. All of the differences identified by the Public Staff in discussing the first element raise adjudicative facts. What are the utilities' jurisdictional revenues? What purchases did they make over the last year? How many did they buy? What were the prices? How will the jurisdictional revenues change? How will prices change? Do this utility's rates include the regulatory fee? If so, at what rate? All of these questions, which will be raised in every filing by a utility for a pass-through of the fee and sales tax changes, raise adjudicative factual issues that must be resolved. The Public Staff states that the Nantahala court accurately pointed out that none of these "who, what, when, where, how," and "how many" questions were present when the item being changed was the "fall out" calculation of a theoretical income tax liability.

According to the Public Staff, the second element stated in Nantahala is partially met here, namely that a large number of utilities are affected. Because adjudicative facts must be determined in each case, individual hearings are appropriate in this case. This request by the Company is much different from the situation resulting from the Tax Reform Act of 1986. In Nantahala, the Court approved the rate changes in a rulemaking when the federal income tax was changed and the impact was very large. The Public Staff compares the effect on the Company in that case of $760,000 with the total requested change of $80,000 included in the Company's original application in this docket. Federal income taxes are very unique. The calculation is purely theoretical and the amount for large utilities is quite significant. The Public Staff agrees with the Company that State income taxes are so similar to federal income taxes that the Commission should allow it to adjust its rates for changes in that tax rate.

The Public Staff takes the further position that the Commission should be sensitive to opening this door any larger than necessary. Fuel taxes change, as do property taxes, excise taxes, unemployment taxes, Social Security taxes, and workers compensation taxes. According to the Public Staff, a change in these taxes does not carry the impact of an income tax change. The Commission should recognize that to adjust rates based on one of these factors without looking at other related factors can be unfair and overly burdensome. For example, should the Commission adjust for changes in Social Security taxes without considering changes in salaries and employment levels? The regulatory fee and the sales tax are more akin to these taxes than to the federal income tax. According to the Public Staff, the changes in the regulatory fee and the sales tax rate do not substantially affect the Company, calculation of the effect will require findings on a number of adjudicative facts, and adjustment of rates by the Commission in this instance may put it on a long and tortuous row that it has to hoe every year.

Thus, the Public Staff asserts that the Commission should not adjust rates to reflect changes in the regulatory fee or the sales tax rate through a rulemaking procedure. Many changes in the law have occurred since the last rate cases of most utilities. Withholding tax rates have changed. Minimum wages have increased. These changes are no different from any other changes in expense items. The Public Staff asserts that if they become burdensome to a utility, it can always file a rate case.

On September 11, 1991, Nantahala filed a response in opposition to the recommendation of the Public Staff and in support of its application. Nantahala argued that its application should be approved based on the Supreme Court's decision in the Nantahala case. Nantahala asserts that the Public Staff's lack of uniformity arguments are without merit because the regulatory fee factor and the sales and use tax rate are the same for all utilities regulated by the Commission. Therefore, Nantahala finds it impossible to distinguish between the tax rate changes addressed in Docket No. M-100, Sub 113, and those at issue in this docket. The Company also revised its filing to request that the rate increase also reflect current Social Security tax rates which apply uniformly to all regulated public utilities.

On September 27, 1991, the Public Staff filed a further response. The Public Staff notes that Nantahala's response assumes that the Commission may in a rulemaking adjust rates downward for a substantial decrease in the federal corporate income tax rate and that the Commission must also in a rulemaking adjust rates upward for any and all increases in tax rates plus the regulatory fee. This assumption is incorrect according to the Public Staff.

The Public Staff points out that the holding of the Court in Nantahala was this:

> that the Commission was acting within its authority when it ordered the affected utilities, including Nantahala, to determine the amount of savings resulting from the TRA-86 and to pass these savings on to the ratepayers.

Id. at 203, 388 S.E.2d at 126. The Court found the formulation of a rule applicable to all utilities similarly situated to be appropriate because

> 1) the tax reduction affected all utilities uniformly; 2) a large number of utilities were affected, making individual hearings for all inappropriate; and 3) no adjudicative-type facts were in dispute so as to require a trial-type hearing for each individual utility.

Id. These three elements are discussed in both the Public Staff's response and recommendation filed on August 30 1991, and Nantahala's response filed on September 11, 1991. The Public Staff's position is that, while the State income tax increase does fall within the procedure upheld in Nantahala, neither the regulatory fee, the sales tax increase, or the Social Security tax increase can be passed on to customers through an increase in rates in a rulemaking since at least two of the Nantahala elements are absent in each case. Nantahala's position is that the Nantahala elements are present. The Public Staff states that if Nantahala is right, and the Public Staff does not concede that it is, then under Nantahala the Commission may by rule applied uniformly increase rates for all utilities similarly affected by tax rate increases and the regulatory fee. According to the Public Staff, the Commission is not, however, required to do so.

The Public Staff notes that in considering the possibility of a tax increase the Court in Nantahala said:

> Should corporate tax rates be increased so that they uniformly and substantially increase taxes for utilities in the same manner as taxes were decreased by the TRA-86, the Commission could, on its own initiative, as it did here, or at the urging of the utilities it regulates, as in Edmisten III, determine in a rulemaking proceeding whether and to what extent rates should be increased to offset the increase in taxes.

Id. at 198, 388 S.E.2d at 123 (Emphasis added). According to the Public Staff, the tax rate increases purportedly giving rise to Nantahala's application in this docket are hardly substantial when compared to the tax rate decrease that was the subject of Docket No. M-100, Sub 113.

In this case, the Public Staff points out that the $760,000 is almost ten times greater than $80,000 Nantahala sought to recover in its original application. The Public Staff categorically denies Nantahala's assertion that "the Public Staff's assessment of the significance of the rate change is dictated more by whether the change is an increase or decrease than the numerical magnitude of the change." If the amount involved here even approached the amount involved in Nantahala, the Public Staff states that it would not have raised the question.

The Public Staff further asserts that even if the total effect of the increases was found to be substantial, the Commission could determine that rates should not be increased to offset them except in a general rate case or a complaint proceeding for an individual utility. According to the Public Staff, the Commission must weigh all the relevant factors in deciding how to proceed, including the number of utilities involved, the number and variety of expense items for which increases are sought, and the extent of the particular investigation likely to be required. In this instance, which involves the application of one utility, the Public Staff asserts that the Commission can reasonably conclude that a rulemaking is inappropriate. If a utility perceives a need for rate relief and aggregates a number of expense item increases to justify a request to raise rates, the Public Staff thinks this is tantamount to filing a general rate case, and nothing in Nantahala would prevent the Commission from declaring it to be one. Adjudicative facts having been called into question, a trial-type hearing would then be required.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

On October 23, 1986, the Commission initiated a generic rulemaking proceeding and investigation in Docket No. M-100, Sub 113, regarding the Tax Reform Act of 1986 and its impact on public utility rates in this State. The Commission Order set forth the following statements concerning the probable impact of TRA-86 on utility rates in North Carolina:

> On October 22, 1986, President Reagan signed into law the Tax Reform Act of 1986. Among other provisions which are contained in this wide-ranging tax reform are provisions which will upon implementation significantly reduce the tax rate of most, if not all, investor-owned public utilities engaged in providing electric, telecommunications, and natural gas distribution services in North Carolina. This reduced tax rate when effectuated will have an immediate and favorable impact on the cost of providing the aforementioned public utility services to consumers in North Carolina. It is incumbent upon this Commission to take the appropriate action as required so as to preserve and flow through to ratepayers, as a reduction to public utility rates, any and all cost savings realized in this regard which would otherwise accrue solely to the benefit of the companies' stockholders. (Emphasis added).

TRA-86 significantly and materially reduced the federal corporate income tax rate by 26.1% from 46% to 34%.

On October 20, 1987, and November 6, 1987, the Commission entered further Orders in Docket No. M-100, Sub 113, establishing procedures to implement tariff reductions and refunds related to the substantial tax savings generated by TRA-86. Nantahala was the only public utility regulated by the Commission to appeal the Commission's final decision.

On February 7, 1990, the North Carolina Supreme Court in the Nantahala decision affirmed our TRA-86 Orders and held that the Commission properly ordered the affected utilities, through a rulemaking procedure, to lower their rates to reflect the substantial federal tax savings generated by TRA-86.

Nantahala now requests the Commission to authorize it to increase its rates and charges to reflect recent changes in the State corporate income tax rate and the sales and use tax rate, as well as to reflect in rates the current Social Security tax rates and the regulatory fee paid by Nantahala pursuant to G.S. 62-302.

The Commission has carefully considered Nantahala's application and concludes that it is not supported by good cause and should be denied in its entirety. While we agree with Nantahala that the tax rate increases and regulatory fee sought by the Company in this proceeding (1) affect all utilities uniformly, (2) affect a large number of utilities, making individual hearings for all inappropriate, and that (3) no adjudicative facts are in dispute so as to require a trial-type hearing for each individual utility, we do not agree that rates should be increased to reflect these tax rate changes and the regulatory fee in the context of a rulemaking proceeding. In our opinion, the tax rate changes and the regulatory fee cited by Nantahala are not substantial or material when considered in the context of the Company's total cost of service. That being the case, they do not justify initiation of a rulemaking proceeding for all public utilities subject to our regulation. For instance, Nantahala's TRA-86 rate reduction was approximately $762,390 per year versus the $113,459 Nantahala seeks to recover for 1991 in this proceeding. The TRA-86 rate reduction was clearly substantial. It was almost seven times greater than the rate increase Nantahala is now seeking. Furthermore, the TRA-86 rate reduction was 3.57% of Nantahala's test year level of revenues in its last general rate case while the increase proposed in this proceeding for implementation through rates in 1991 amounts to only 0.53% of the Company's test year revenues.

While some may argue that the 11% increase in the State corporate income tax rate from 7.0% to 7.75% is substantial, we do not agree, particularly when compared to the TRA-86 rate reduction of 26.1%. Furthermore, the increase in the State income tax rate of 0.75 percentage point plus the surcharge pales in comparison to the federal rate reduction of 12 percentage points from 46% to 34%. For example, if the TRA-86 federal and the 1991 state corporate income tax rate changes are compared in terms of net effect (i.e., after recognition of the federal income tax effect arising from the state income tax increase), the result is that the impact of the TRA-86 federal income tax rate reduction was 24 times greater than the current state income tax increase. Simply put, federal income taxes compose a much larger and more significant part of the cost of service for all regulated utilities in North Carolina than State corporate income taxes.

We also note in support of our decision that when the federal corporate income tax rate was reduced from 48% to 46% in 1978, the Commission did not then initiate a rulemaking proceeding to reduce public utility rates. That tax rate reduction was not substantial in the eyes of the Commission. Like the rate increase being sought by Nantahala in this case, it was not material and did not warrant initiation of a generic rulemaking proceeding affecting all public utilities. Likewise, the Commission has never before initiated a rulemaking proceeding to flow through changes in other tax rates, such as Social Security taxes or sales taxes which frequently change. Such changes are clearly insubstantial when measured against the total cost of service of the public utilities we regulate. Rulemaking procedures should only be used to increase or decrease public utility rates when changes are clearly substantial and material. Otherwise, a general rate case where all items of the cost of service are carefully scrutinized is the most appropriate forum for rate relief. Furthermore, our decision to deny Nantahala's application is a matter within our sound discretion as indicated by the following language of the Supreme Court in the Nantahala case:

> Should corporate tax rates be increased so that they uniformly and substantially increase taxes for utilities in the same manner as taxes were decreased by the TRA-86, the Commission could, on its own initiative, as it did here, or at the urging of the utilities it regulates, as in Edmisten III, determine in a rulemaking proceeding whether and to what extent rates should be increased to offset the increase in taxes.

Id. at 198, 388 S.E.2d 123 (Emphasis added). We conclude that the tax rate increases giving rise to Nantahala's application in this docket are insubstantial when compared to the tax rate decrease that was the subject of Docket No. M-100, Sub 113.

Accordingly, the Commission concludes that a rulemaking proceeding is inappropriate and that Nantahala's application should be denied. Nantahala's proposal raises issues which are more properly considered in the context of a general rate case since all elements of the Company's total cost of service, and not just taxes and regulatory fee expense, have undoubtedly changed since the Company's last general rate case was decided in 1983, some eight years ago.

IT IS, THEREFORE, ORDERED that the application filed in this docket by Nantahala Power and Light Company on August 6, 1991, as amended on September 11, 1991, be, and the same is hereby, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of October 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioners Sarah Lindsay Tate, Laurence A. Cobb, and Allyson K. Duncan dissent.

COMMISSIONER TATE, DISSENTING: I dissent from this order because it does not comply with the decision of the Supreme Court in State ex. rel. Utilities Commission v. Nantahala Power & Light Co., 326 N.C. 190 (Nantahala).

In Nantahala, the Court ruled that the Commission may decrease utilities' rates in a rulemaking procedure when corporate tax rates are decreased. A majority of the Commission has now decided not to increase utilities' rates when corporate tax rates are increased. The majority argues that the increase in the state income tax is not as "substantial" as the 1986 TRA decrease in corporate income taxes. But Nantahala argues that the tax increases and surtaxes are "substantial" to it. The majority states that the TRA reduction was a 26% rate decrease in the federal tax rate; this should be compared to the state income tax rate increase of 11% which also is substantial, and the Public Staff agrees. I am confident the Commission would immediately flow through an 11% tax decrease.

When the TRA of 1986 was passed on October 22, 1986, the Commission acted on October 23 to set up a mechanism for dealing with the "windfall" to utilities. However when the General Assembly increased taxes on July 13, 1991, there was no concomitant action to deal with the "shortfall" to utilities. Even after Nantahala in August requested a rate adjustment and rulemaking, no mechanism was put in place to preserve the "lost" revenues pending a decision. And there still is no mechanism in place pending appeal. I presume if the Court finds that Nantahala's rates should have been increased, the majority will rule that it cannot increase rates retroactively.

In my dissent to the first Nantahala order, I said the Commission had opened the floodgates to future confusion in dealing with future tax increases or decreases. Now in this proceeding, distinctions are being made between income taxes, surtaxes, sales and use taxes and regulatory fees. It is confusing and will continue to be so. What is clear is that the majority finds it much easier to deal with tax decreases than tax increases. Fundamental fairness and the Nantahala decision require that both should be treated the same way.

Commissioner Sarah Lindsay Tate

DOCKET NO. E-100, SUB 59

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Biennial Determination of Avoided Cost Rates for Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities	)	ORDER AMENOING COMMISSION RULE R1-37(d)(3)

BY THE COMMISSION: On May 14, 1991, the Public Staff filed its Motion to Amend Rule RI-37 in this docket. Commission Rule RI-37 deals with certificates of public convenience and necessity for qualifying cogeneration and small power producers. Rule R1-37(d)(3) provides as follows:

> Until the time construction is completed, all certificate holders must advise the Commission of any plans to transfer or assign the certificate or of any changes in the information set forth in subsection (b)(I) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

Thus, the Rule only requires that changes occurring before completion of construction be reported to the Commission. The Public Staff moves that transfers and assignments occurring after a qualifying facility has been constructed should also be reported to the Commission "as a means of keeping the Commission's records accurate and up-to-date."

On May 30, 1991, Duke filed a Response supporting the Public Staff's request and suggesting two further refinements, one dealing with notice to the utility as well as to the Commission, and a second dealing with facilities that are exempt from the certificate requirements.

The Commission has carefully considered the Motion and Response. The Commission notes that Rule R1-37 applies to certificates of public convenience and necessity issued pursuant to G. S. 62-110.1(a), and is a certificate for construction of an electric generating facility. Nonetheless, the Commission agrees with the Public Staff that it is important for the Commission, as well as the utility involved, to be kept informed as to the ownership and other essential characteristics of electric generating facilities constructed pursuant to such a certificate. To that end, the Commission finds good cause to require that Commission Rule R1-37(d)(3) be amended to provide that all transfers, assignments, or significant changes be reported to the Commission and to the utility involved. The Commission therefore amends Commission Rule R1-37(d)(3) to read as follows:

> Both before the time construction is completed and after, all certificate holders must advise both the Commission and the utility involved of any plans to sell, transfer, or assign the certificate or the generating facility or of any significant changes in the

information set forth in subsection (b)(1) of this Rule, and the Commission will order such proceedings as it deems appropriate to deal with such plans or changes.

IT IS, THEREFORE, ORDERED that Commission Rule R-37(d)(3) should be, and the same hereby is, amended as hereinabove provided.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-100, SUB 59

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Biennial Determination of Avoided Cost Rates For Sale and Purchase of Electricity Between Electric Utilities and Qualifying Facilities) ORDER ESTABLISHING STANDARD RATES AND CONTRACT TERMS FOR QUALIFYING FACILITIES

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on March 12-13, 1991

BEFORE: Commissioner Julius A. Wright, Presiding; and Commissioners Sarah Lindsay Tate and Robert O. Wells

APPEARANCES:

For the Respondents:

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and
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For: Carolina Power and Light Company

William Larry Porter, Associate General Counsel and Karol G. Page, Senior Attorney, Duke Power Company, 422 South Church Street, Charlotte, North Carolina 28242-0001
For: Duke Power Company

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For: North Carolina Power

Edward S. Finley, Jr., Hunton and Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602
For: Nantahala Power and Light Company

For the Intervenors:

Samuel J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28655
For: Carolina Utility Customers Association, Inc. (CUCA)

Ralph McDonald and Carson Carmichael, III, Bailey and Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605-2865
For: Carolina Industrial Group for Fair Utility Rates (CIGFUR II)

Gisele L. Rankin, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629
For: The Using and Consuming Public

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For: Empire Power Company

BY THE COMMISSION: These are the current biennial proceedings held by this 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, qualifying 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," and thus become eligible for the rates and exemptions established in accordance with Section 210 of PURPA.

Each electric utility is required under Section 210 of PURPA to offer to purchase available electric energy from cogeneration and small power production facilities 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 the FERC rules described herein 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.

This Commission at the outset determined to implement Section 210 of PURPA and the related FERC regulations by holding biennial proceedings. This proceeding is the latest of many such proceedings held by this Commission since the enactment of PURPA. In prior biennial proceedings, the Commission has determined avoided cost rates for five electric utilities in North Carolina. The Commission has also reviewed and approved other related matters involving the relationship between the five electric utilities and the qualifying facilities interconnected with them, such as terms and conditions of service, contractual arrangements, and interconnection charges.

This proceeding also involves the carrying out of this 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 or less, thus excluding users of other types of renewable resources.

On July 3, 1990, the Commission issued its Order Establishing Biennial Proceeding, Requiring Data and Scheduling Public Hearing in this proceeding. That Order made Carolina Power and Light Company (CP&L), Duke Power Company (Duke), Virginia Electric and Power Company, d/b/a North Carolina Power (NC Power), Nantahala Power and Light Company (Nantahala), and Western Carolina University (WCU) parties to the proceeding to establish the avoided cost rates each is to pay for power purchased from qualifying facilities pursuant to the provisions of Section 210 of PURPA and the FERC regulations implementing those provisions and to establish the rates each is to pay for power purchased from small power producers as required by G.S. 62-156. The Order required each of the five electric utilities to file certain specified data and any direct testimony by August 13, 1990.

On August 8, 1990, the Public Staff filed a motion to continue the hearing in order for it to be able to hire a consultant to investigate and make recommendations as to the best ways to integrate least cost planning and the administrative determination of avoided costs. By Order dated August 9, 1990, the Commission rescheduled the hearing to begin March 12, 1991, required the utilities to file the required information by September 10, 1990, and required all other parties to intervene and file direct testimony by January 29, 1991.

On September 7, 1990, Nantahala filed a Motion for Extension of Time within which to prefile testimony. On September 10, 1990, the Commission issued an Order allowing Nantahala to prefile testimony on or before October 10, 1990.

On December 21, 1990, Carolina Utility Customers Association (CUCA) filed a Petition to Intervene. By Order dated December 27, 1990, the Commission allowed CUCA to intervene.

On January 24, 1991, Hadson Development Corporation filed a Petition to Intervene and a Motion to Extend Time within which to prefile testimony. On that same date, the Public Staff filed a Motion for Extension of Time within which to prefile testimony.

On January 25, 1991, the Commission issued orders allowing the intervention by Hadson Development Corporation, allowing Hadson to prefile testimony on or before February 13, 1991, and allowing the Public Staff to prefile testimony on or before February 6, 1991.

On January 28, 1991, Carolina Industrial Group for Fair Utility Rates (CIGFUR II), an industrial group comprised of Federal Paper Board Company, Inc., Huron Chemicals of America, Inc., LCP Chemicals & Plastics, Inc., Monsanto Company, Texasgulf, Inc., and Weyerhauser Company, filed a Petition to Intervene and a motion for extension of time to file testimony. The Commission allowed CIGFUR II to intervene and granted its request for an extension of time to file testimony by Order issued January 29, 1991.

On February 1, 1991, the Attorney General filed its Notice of Intervention. On February 5, 1991, the Public Staff made an oral Motion for a further extension of time within which to prefile its testimony. On February 6, 1991, the Commission issued an Order allowing the Public Staff to prefile its testimony on or before February 8, 1991.

On February 15, 1991, WCU filed a motion requesting that its testimony be copied into the record without the presence of its witness and that it be excused from appearing at the hearing. By Order dated March 1, 1991, the Commission granted Western Carolina's motion.

On March 8, 1991, Empire Power Company filed a Petition to Intervene. On March 11, 1991, Duke filed its objections to Empire's intervention. The Commission allowed the intervention at the beginning of the hearing on March 12, 1991.

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

The utilities and the Public Staff filed their testimony as required by the Commission's Order of August 9, 1991, or by the extended date where extensions were allowed. No other party filed testimony. The matter came on for hearing on March 12, 1991, as previously noticed and scheduled. The prefiled testimony of George W. Wooten, offered on behalf of WCU, was copied into the record without Mr. Wooten being present to testify. Pursuant to the stipulation of all the parties, the prefiled testimony of Nantahala witness N. Edward Tucker, Jr., was copied into the record without Mr. Tucker being present to testify.

NC Power presented the testimony of a panel consisting of its employees as follows: Ripley C. Newcomb, Director of Rate and Load Research; Daniel J. Green, Director of Planning Services; and Robert W. Carney, Director of Capacity Contracts. Mr. Newcomb explained the changes the Company proposes to its Rate Schedules 19 and 19H. Mr. Green discussed the Differential Revenue Requirement (DRR) methodology and how the yearly generation mixes from the Company's resource plan were used to determine avoided energy rates. Mr. Carney discussed the status of the non-utility power production contracts, the Company's competitive bidding process, and modifications to the Company's standard contracts.

Duke Power presented the testimony of a panel consisting of its employees as follows: John N. Freund, Manager of Rate Design, and Kenneth B. Keels, Jr., Purchased Power Contracts Manager. Mr. Freund presented and explained the calculations supporting the Company's proposal for revision of its Schedule PP (NC). Mr. Keels testified with regard to Duke's experience with QFs and with respect to changes in Duke's Standard Purchased Power Agreement and to the term and conditions of Schedule PP(NC).

CP&L offered the testimony of G. Wayne King, its Director of Rate Studies. Mr. King presented CP&L's proposed Cogeneration and Small Power Producer Schedule CSP-14, and updated the Commission on the amount of QF capacity on CP&L's system.

The Public Staff presented the testimony of Dr. John H. Chamberlin, Executive Vice-President of Barakat and Chamberlin, an economic and management consulting firm specializing in public utility economics. He presented the results of Barakat and Chamberlin's review of the September 1990 avoided cost filings of Duke, CP&L, and NC Power and of Barakat and Chamberlin's investigation into the consistency between the methodologies previously established for determining avoided costs and least cost integrated resource planning principles.

The following public witnesses appeared at the hearing and testified: Joe R. Ellen, Jr., owner and operator of Rocky River Power Plant; Steve Cook, owner and operator of High Falls Plant; Lynwood Bullock, owner and operator of Cedar Falls Plant; Tim Henderson, developer of two potential hydroelectric facilities on Mayo River; and Charles Wood, involved in development of two potential hydroelectric facilities on Mayo River.

Following the hearing, the Public Staff filed a Motion Re ENPRO on March 21, 1991, requesting the Commission to require CP&L to recompute its avoided energy rates based upon alternative projections of nuclear capacity factors for the Brunswick and Robinson nuclear units. CP&L filed its Response on March 28, 1991, and the Public Staff filed a reply to CP&L's Response on April 4, 1991. The Attorney General filed a motion joining the Public Staff in its motion on

April 2, 1991. The Commission issued its Order on April 22, 1991, deferring a decision on the Public Staff's motion until after the parties had addressed in their proposed orders the issue of the appropriate nuclear capacity factor projections to be used by CP&L.

On May 14, 1991, the Public Staff filed a Motion in this docket to amend NCUC Rule R1-37 so as to require all certificate holders to obtain the Commission's approval prior to transferring or assigning any certificate or making any significant change in the information required under subsection (b)(1) of the Rule. On May 30, 1991, Duke filed its Response.

On August 2, 1991, the Public Staff filed a Motion To Amend Contents of Status Reports in this docket in which it requests that the Commission alter the contents of the annual status reports required of the electric utilities to include information on IPPs and the size of NUG generating facilities. On August 19, 1991, Duke filed its Response. CP&L filed its Response on August 23, 1991.

Based on the foregoing, the testimony and exhibits offered at the hearing and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. CP&L and Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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.

2. NC Power shall offer long-term levelized capacity payments with 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 qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power producers as that term is defined in G.S. § 62-3(27a) or (b) any other qualifying facility which contracts to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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.

3. NC Power's proposed long-term energy payments to small QFs, based on a levelized generation mix with fuel prices indexed to current fuel prices, should be approved on a permanent basis.

4. NC Power should develop and offer a fixed long-term levelized energy payment as an additional option for small QFs rated at 100 kW or less.

5. Nonhydroelectric qualifying facilities contracting to sell generating capacity of more than five megawatts to either Duke or CP&L should have the options of contracts at the variable rates set by the Commission herein or contracts at negotiated rates and terms.

6. Nonhydroelectric qualifying facilities larger than five megawatts capacity desiring to sell generating capacity to NC Power should participate in its competitive bidding process for obtaining additional capacity.

7. Nantahala and WCU should not be required to offer any long-term levelized rate options to qualifying facilities.

8. The Commission will not set specific guidelines for negotiations between utilities and qualifying facilities. Nevertheless, the Commission expects all utilities to negotiate in good faith with qualifying facilities.

9. Appropriate protection for the utilities against financial loss due to default by a QF on a contract for long-term levelized rates is a matter best left to negotiation between the utilities and those nonhydroelectric QFs contracting to sell more than 5 mW capacity. Hydroelectric QFs contracting to sell 80 mW or less capacity and nonhydroelectric QFs contracting to sell 5 mW or less capacity should not be required to offer such protection against financial loss.

10. The general methodologies and planning models used by North Carolina Power, Duke and CP&L to develop their respective avoided costs are consistent with each other and with past Commission orders.

11. Duke and CP&L use the peaker method to develop avoided capacity costs. NC Power uses the 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.

12. The input assumptions used by NC Power, Duke and CP&L to calculate avoided costs are generally consistent with each utility's historical operating experience, published forecasts and escalation rates, and data used by other utilities for similar purposes.

13. CP&L's projected nuclear capacity factors for the Brunswick and Robinson plants resulting from CP&L's ENPRO model are reasonable for purposes of this proceeding.

14. CP&L's proposed avoided capacity costs contain fixed O&M costs that are based on EPRI's Technical Assessment Guide (TAG) data rather than on company-specific information. Such fixed O&M costs are reasonable for purposes of this proceeding.

15. CP&L's proposal to include variable O&M expenses in the energy credits instead of in the capacity credits is reasonable.

16. Duke's proposed avoided capacity costs contain its best estimates of the fixed capital costs for new combustion turbines. Such estimates are reasonable for purposes of this proceeding.

17. Duke's proposed avoided capacity costs contain a component for the costs of overhauling CTs. Including such overhaul costs as a fixed O&M component of avoided capacity costs is reasonable for purposes of this proceeding.

18. Duke should follow CP&L's method and levelize avoided variable energy credits over a two-year period, beginning with 1991-1992.

19. Duke's proposed addition of paragraph 1.4 to its Standard Purchased Power Agreement in order to require a "capacity commitment" by the supplier in place of the previous "maximum amount of electric power" is reasonable and should be approved. The language contained in proposed paragraph 1.4 should not be used to reduce capacity payments paid to QFs for delivery of capacity pursuant to Schedule PP(NC) under the Standard Purchased Power Agreement without specific approval of this Commission.

20. Duke's proposed addition of paragraph nine to its Standard Purchased Power Agreement in order to allow it to begin charging its Interconnection Facilities Charge prior to the Initial Power Delivery Date should not be approved in this proceeding.

21. The "Reserve Margin Adjustment" currently included in avoided capacity cost calculations for Duke and CP&L should be renamed the "Performance Adjustment".

22. Duke and CP&L should not be required to file a tariff offering capacity credits to QFs for peaking-type resources on a $ per kW basis as well as on a ¢ per kWh basis as discussed herein. The Commission should make its determination in the matter after reviewing further comments from the affected parties.

23. NC Power should study its DRR methodology in order to determine whether a more accurate split between capacity costs and energy costs can be made. Its findings and solutions should be presented in the next biennial proceeding.

24. NC Power should study its method of calculating capacity costs in order to determine if its capacity credits should include a 20% performance adjustment. Its analysis should be presented in the next biennial proceeding.

25. NC Power should study its practice of calculating capacity payments on the basis of 3120 hours and subsequently applying such capacity payments to a maximum of 3120 hours in order to determine whether its practice is consistent with application of a 20% performance adjustment. Its analysis should be presented in the next biennial proceeding.

26. NC Power's proposal to reduce power purchases from a QF during periods of "light load conditions" is not appropriate in this proceeding. NC Power should monitor the experience of QFs under its proposal in Virginia and bring the matter back to the North Carolina Commission in the next biennial proceeding.

27. NC Power's proposal to offer non-time-of-use energy credits as an option to small QFs rated at 100 kW or less is reasonable.

28. NC Power's proposal to eliminate Schedule 19H should be approved because the schedule will no longer be needed.

29. Proposed Rate Schedule CG for Nantahala Power and Light Company is reasonable and appropriate.

30. Western Carolina University's proposed Small Power Production Supplier Reimbursement Formula is reasonable and appropriate.

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

32. The Public Staff should continue to monitor the QF contract activities of CP&L, Duke and NC Power in order to ensure that avoided cost rates and contract activities are consistent with least cost integrated resource planning activities.

33. The Public Staff Motion To Amend Rule R1-37 and its Motion To Amend Contents of Status Reports are decided by separate orders in this docket.

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

The evidence in support of this finding is contained in the testimony of CP&L witness King, Duke witnesses Freund and Keel, NC Power witnesses Newcomb and Green, and Public Staff witness Chamberlin.

A major issue in prior avoided cost proceedings has been whether the Commission should require the electric utilities to offer long-term levelized rates to qualifying facilities as standard rate options. Long-term levelized rates are permitted, but not required, by the regulations implementing Section 210 of PURPA. The commentary to the regulations includes the following:

> A facility which enters into a long-term contract to provide energy or capacity to a utility may wish to receive a greater percentage of the purchase price during the beginning of the obligation. For example, a level payment schedule from the utility to the qualifying facility may be used to match more closely the schedule of debt service of the facility. So long as the total payment over the duration of the contract term does not exceed the estimated avoided costs, nothing in these rules would prohibit a state regulatory authority or nonregulated electric utility from approving such an arrangement.

G.S. § 62-156(b)(1), which applies to small power producers as defined by G.S. § 62-3(27a), provides, "Long-term contracts for the purchase of electricity by the utility from small power producers shall be encouraged in order to enhance the economic feasibility of small power production facilities."

Prior to this proceeding, CP&L and Duke were required to offer standard long-term levelized rate options only to small qualifying facilities. 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. As a result of concerns raised by the utilities and the Public Staff with respect to the effect of these options, the Commission limited the standard long-term levelized rate options to hydroelectric facilities of 80 MW or less and to nonhydroelectric qualifying facilities with generating capacity of five megawatts or less.

In this proceeding CP&L and Duke proposed no change in the availability of long-term levelized rates. Upon cross-examination, Public Staff witness Chamberlin stated that he did not propose any change in the present limitations on the availability of their standard long-term levelized rates.

The General Assembly has clearly indicated in G.S. § 62-156 a policy of encouraging hydroelectric facilities. Additionally, we note that many of the risks associated with standard long-term levelized rate options are either not present or tend to be minimized in the case of most hydroelectric facilities. For example, hydroelectric facilities are not subject to the risks associated with changes in fossil fuel costs or the business risks associated with the heat recovery aspect of cogeneration projects. Further, more of the capital costs involved in a hydroelectric facility tend to be "up front" costs which must be financed. Levelized rates facilitate financing by providing a degree of certainty and by allowing an income stream which more evenly matches the debt payments required by financing. Finally, hydroelectric facilities by their very nature tend to entail a degree of permanence and stability as regards the major components of the facility, such as the dam and powerhouse. In light of the foregoing reasons, we believe and conclude that CP&L and Duke should continue to offer long-term levelized rate options to hydroelectric qualifying facilities less than 80 MW as standard rate options.

With respect to nonhydroelectric qualifying facilities contracting to sell five megawatts or less, CP&L and Duke should continue to offer long-term levelized rate options. As noted in previous orders, the risks associated with a nonhydroelectric qualifying facility in the event of a default on a long-term levelized rate contract of five megawatts or less capacity is relatively small in terms of dollar exposure and impact on supply when contrasted with the risks associated with such a default on a larger contract. In addition, standard rate options will tend to encourage small projects, the owners of which probably would not have the resources or the expertise to negotiate with the utility.

Thus, based on the foregoing and the record as a whole in this proceeding, the Commission concludes that CP&L and Duke should offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power producers as that term is defined in G.S. § 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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.

The evidence and conclusions supporting the finding of fact for NC Power is the same as that set forth herein for Duke and CP&L. However, instead of a fixed long-term levelized energy payment, NC Power offers an energy payment based on a long-term levelized generation mix with adjustable fuel prices. NC Power has proposed no change to the limitation on the availability of its Schedule 19 and no party has opposed the limitation. Accordingly, NC Power should continue to offer long term levelized capacity payments with 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 qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility which contracts to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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 rate and other relevant factors or (2) set by arbitration.

Furthermore, in the last biennial proceeding, NC Power was authorized to offer the energy payments based on a long-term levelized generation mix with adjustable fuel prices on an experimental basis. The Commission is now of the opinion that the proposal by NC Power should be approved on a permanent basis. No other party has opposed the levelized generation mix as a basis for calculating energy payments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence in support of this finding is contained in the testimony of NC Power witnesses Newcomb and Green and Public Staff witness Chamberlin.

Public Staff witness Chamberlin proposed that NC Power offer a fixed long-term levelized energy payment as an option to small QFs for Schedule 19 firm power purchase contracts. His recommendation is for the purpose of encouraging smaller QFs. The risk of overpayment to smaller QFs as a result of long-term levelized energy payments is outweighed by the need to encourage generation by such small QFs, given the limited potential financial impact such small QFs may have on the utility. NC Power proposed to make available a long-term levelized payment to QFs rated at 100 kW or less.

The risk of overpayment associated with long-term levelized energy payments to larger QFs is similar but may involve more substantial financial impacts upon the utility and its ratepayers. The Commission believes that the risk of overpayment associated with such a pricing option for larger QFs should not be borne by NC Power's ratepayers. The avoided energy mix methodology adequately compensates QFs while balancing the competing interests of the ratepayers. Accordingly, NC Power should not be required to offer long-term levelized energy payments to QFs rated in excess of 100 kW in this proceeding.

In summary, the avoided generation mix methodology balances the interests of both ratepayers and QFs. Smaller QFs should be encouraged to the extent such encouragement does not result in a substantial shift in the risk of default to ratepayers. Accordingly, NC Power should develop and offer a fixed long-term levelized energy payment option for small QFs rated at 100 kW or less.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

As in previous avoided cost proceedings, the Commission continues to believe that nonhydroelectric QFs contracting to sell greater than 5mWs of generating capacity to either CP&L or Duke should have the options of contracts at the variable rates set by the Commission herein or contracts at rates derived by free and open negotiation with the utility.

As in past proceedings, NC Power's competitive bidding solicitation program has been explained to the Commission and the Commission concludes that nonhydroelectric facilities desiring to sell generating capacity of more than five megawatts to NC Power should participate in that bidding process.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The Commission's conclusion that Nantahala should not be required to offer any standard long-term levelized rate options to qualifying facilities flows from the Commission's conclusions in the previous biennial proceedings that the unique nature and circumstances of Nantahala's power supply arrangements make such options infeasible. That conclusion has not been challenged by any party in this proceeding. While Nantahala owns some generating units, it is unable to service its load from those sources alone. It therefore must purchase capacity and/or energy under contract from others. Because of these contractual arrangements and the inherent uncertainty and monthly variations involved in such arrangements, it is not feasible to require Nantahala to offer any form of standard long-term levelized rate options to qualifying facilities.

The same considerations apply to WCU. WCU has no generating facilities of its own and buys all of its power from Nantahala under an arrangement which is similar to that between Nantahala and its suppliers in the past.

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

The Commission expects all utilities to negotiate in good faith with qualifying facilities for such terms as are fair to the qualifying facility as well as to the utility's ratepayers. The Commission takes this opportunity to stress again the responsibility of the utilities in these negotiations. Any qualifying facility may file a complaint with the Commission if it feels that a utility is not negotiating in good faith.

As in the past, the Commission will not set specific guidelines for such negotiations. We would expect such negotiations to address such problems as the following:

(a) The appropriate contract duration and the parties' best forecast of avoided capacity and energy credits over the contract duration;

(b) Capacity credits that reflect the need (or lack of need) for additional capacity at the time deliveries under the contract are actually to be made;

(c) The availability of capacity during the utility's daily and seasonal peak periods;

(d) The utility's ability to dispatch the qualifying facility;

(e) The expected or demonstrated reliability of the qualifying facilities;

(f) The terms and provisions of any applicable contract or other legally enforceable obligation, including the termination notice requirement and sanctions for noncompliance;

(g) The extent to which the scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility;

(h) The usefulness of capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(i) The individual and aggregate value of the capacity from qualifying facilities on the utility's system;

(j) The smaller capacity increments and the shorter lead times which might be available with additions of capacity from qualifying facilities;

(k) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from the qualifying facility;

(l) The alternative of long-term rates that are not levelized or only partially levelized;

(m) The alternative of long-term rates that include levelized capacity payments and variable energy payments;

(n) Appropriate notice prior to the expiration of the contract term, the renewability of the contract, and provisions for setting the appropriate rates for such renewed contract; and

(o) The appropriate security bond or other protection for the utility if levelized or partially levelized payments are negotiated.

As in past proceedings, the Commission concludes in this proceeding that appropriate protection for the utilities against any financial loss they might suffer if a qualifying facility with a long-term contract at levelized rates defaults after receiving overpayments during the early part of the contract is a matter best left to negotiation between the utilities and those nonhydroelectric qualifying facilities contracting to sell more than five megawatts capacity. The Commission will not require such protection for hydroelectric qualifying facilities or for nonhydroelectric qualifying facilities contracting to sell less than five megawatts capacity.

Negotiated contracts between a utility and a qualifying facility should, upon execution, be submitted to the Commission and such contracts will be accepted for filing. Such contracts, after being filed, shall be subject to review in the context of the utility's next filed general rate case or by a complaint proceeding, just as would any other contract by the utility.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 10 THROUGH 12

The evidence in support of this finding is contained in the testimony of NC Power witness Green, Duke witness Freund, CP&L witness King, and Public Staff witness Chamberlin.

The Commission approved the least cost integrated resource plans of the participating utilities in Docket No. E-100, Sub 58. In this docket, the Public Staff directed witness Chamberlin to investigate the consistency between the methodologies used to determine avoided costs and the least cost integrated resource plans adopted in Docket No. E-100, Sub 58. Witness Chamberlin reviewed the filings of NC Power, Duke and CP&L and determined that the general methodologies and planning models used to develop the utilities' integrated resource plans and avoided costs are consistent with each other and with past Commission orders. This determination was uncontested by any witness.

The DRR methodology requires a utility to identify how it would adjust its schedule of planned capacity additions in response to an increase in power supplied by QFs. The change in costs associated with the adjustment is used to calculate avoided capacity costs. The DRR methodology is used by NC Power to develop avoided capacity costs and energy costs.

The peaker methodology requires a utility to develop marginal capacity costs using the supply side resource with the lowest investment cost for achieving peak capacity, which is usually a combustion turbine. The peaker methodology is used by both Duke and CP&L to develop avoided capacity costs.

The peaker method and the DRR method should produce similar results in situations where a utility has identified a near-term need for new peaking capacity. Witness Chamberlin indicated that both the peaker method and the DRR method are generally accepted and used throughout the electric utility industry and this Commission has approved the use of both methods in past proceedings.

The input assumptions used by NC Power, Duke and CP&L in the course of their respective applications of the DRR and peaker methodologies are generally consistent with each utility's historical operating experience, published forecasts and escalation rates, and data used by other utilities for similar purposes. Neither the methodologies nor the assumptions used in those methodologies were contested by any witness. Accordingly, the Commission concludes that the DRR methodology as applied by NC Power and the peaker methodology as applied by Duke and CP&L are reasonable for purposes of this proceeding.

CUCA contended in its filed brief that if avoided capacity costs are based on a peaking unit, then avoided energy costs should also be based on a peaking unit. The Commission has pointed out in previous orders in these biennial proceedings that the fixed costs of a peaking unit represent a proxy for the capacity related portion of the fixed costs for any avoided generating unit. However, the energy costs of a peaking unit are not an appropriate proxy for the average avoided energy costs of the entire generation mix.

CIGFUR II contended in its filed brief that avoided capacity costs should be based on base load capacity instead of peaking capacity in order to better reflect the cost of providing the next unit of capacity that will be needed. However, CIGFUR offered no witness to rebut the current plans by the utilities to add peaking capacity to their systems.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact can be found in the testimony of Public Staff witness Chamberlin, the oral arguments of counsel for the Public Staff and CP&L, the post-hearing Motion Re ENPRO of the Public Staff, Response to Motion of the Public Staff by CP&L, and the Public Staff's Reply to CP&L's Response.

Witness Chamberlin testified that the average projected 1991 running costs for CP&L's plants were higher than recorded 1989 figures, as would be expected, with the exception of the three nuclear plants and the Cape Fear gas turbine. These nuclear plants' projected 1991 running costs were lower because of the relatively low 1989 capacity factors and the increased utilization of these plants in the forecast, as input to ENPRO. He further testified that the capacity factor projections for baseload plants used to determine avoided energy costs should be consistent with the units' expected performance. If the nuclear plant capacity factor projections used by CP&L are higher than expected, then the Commission may wish to have CP&L compute avoided energy costs based on alternative projections. He also testified that his firm reviewed the inputs CP&L used to calculate the avoided fuel costs and found the inputs to be reasonable and within the ranges used by other utilities for similar purposes.

The Public Staff requested permission to file a written motion after the close of the hearing regarding the recomputation of fuel costs by CP&L, which was granted by the Commission. The Public Staff filed its Motion Re ENPRO on March 21, 1991, setting out the historical capacity factors of the Brunswick and Robinson nuclear plants and requesting that the Commission require CP&L to recompute its avoided energy rates using assumptions in its ENPRO modeling that produce capacity factors approximating the most recent five-year averages for the Brunswick and Robinson plants.

In support of its motion, the Public Staff asserted that the capacity factors utilized for 1991 by CP&L in its ENPRO model used to calculate the avoided energy costs were higher than historical capacity factors of the Brunswick and Robinson units. The Public Staff stated that by factoring into the model higher capacity factors than the units had achieved historically, CP&L had overstated the availability of approximately 2,245 mW of nuclear capacity, which would have the effect of reducing avoided energy costs.

CP&L responded to the Public Staff's motion by stating that the purpose of this proceeding was to set future avoided costs which should be properly based on the projected operating characteristics of the various units and that no party to this proceeding had introduced evidence challenging CP&L's projections. The projections were set forth in CP&L's filing and in CP&L's responses to discovery served on CP&L by the Public Staff's consultant, witness Chamberlin. CP&L did not dispute that the use of different nuclear unit assumptions in its model would have an effect on CP&L's avoided energy costs; however, CP&L objected to being required to run different ENPRO models utilizing historical capacity factors for the Brunswick and Robinson Units due to the timing of the Public Staff's motion. Further, CP&L objected to the motion of the Public Staff to recompute avoided energy costs based on revising only one input to the entire avoided costs equation.

CP&L noted that the Public Staff did not address the Harris nuclear plant, which is also included in the avoided cost calculations. It contended that any increase in avoided costs caused by a decrease in Brunswick and Robinson capacity factors will be partially off-set by reductions in avoided costs caused by Harris capacity factor increases, thereby producing a negligible overall change in avoided costs.

CP&L stated that it calculated avoided costs by utilizing its nuclear operating plan, a plan that is employed to derive projected fuel expenses for corporate budgeting and planning purposes. This plan provides essential information considered in the development of the nuclear fuel design which determines quantities and prices of nuclear fuel to be purchased. The plan also contributes to the development of a coal buying strategy which determines the quantity and price of coal purchased under contract and from the spot coal market. The nuclear operating plan is also a contributing factor in the development of the Company's Resource Plan which schedules construction of new generating facilities and power purchases. CP&L contended that to utilize assumptions that result in a different nuclear capacity factor for calculating avoided costs while ignoring their impact on resource planning, fuel procurement practices, and budgeting is inappropriate and creates an inconsistency in the information being used by the Company in different regulatory proceedings, and, just as importantly, in the everyday conduct of its business.

The Public Staff filed a reply on April 4, 1991, which pointed out CP&L has the burden of proof to establish its proposed rates are reasonable. The Public Staff further contended that CP&L had offered no evidence to support the nuclear capacity factors challenged in this proceeding or disputed their effect on avoided energy rates.

The Commission, having fully weighed the arguments presented by the Public Staff, which were joined in by the Attorney General, and the arguments of CP&L, agrees with CP&L that the Public Staff's motion to recompute its avoided energy costs based on different nuclear capacity factors and without changing any other variable with respect t• the total composition of the rate, would be inappropriate. The Commission further finds it inappropriate to litigate this issue in post-hearing motions.

It would have been helpful to the Commission to see comparisons made between the Public Staff's approach to this issue and CP&L's approach during the course of the hearing where each one would have been subject to cross-examination. However, as pointed out by CP&L, such comparisons now would inevitably raise other issues which might not be resolvable without further discovery and opportunity for cross-examination.

Therefore, the Commission concludes that the projected nuclear capacity factors for CP&L's nuclear plants resulting from its ENPRO model are reasonable for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding of fact is found in the testimony and exhibits of CP&L witness King and Public Staff witness Chamberlin.

Witness Chamberlin testified that CP&L's estimate of the fixed operating and maintenance costs (O&M) that are added to the capital costs of a CT under the Peaker Method was based on 1984 data in EPRI's 1986 Technical Assessment Guide (TAG), and then updated to current levels using construction cost indexes for the South Atlantic region. The resulting value of $.066/kW-year is significantly below Duke's and NC Power's fixed O&M costs. Because Duke's value of $2.68/kW-year (in 1991 dollars) is based on Duke's new CT purchase contract, Dr. Chamberlin testified that it was superior to the TAG data as a basis for making the estimate and should be applied to CP&L as well. He further testified that CP&L should use its actual costs or estimates based on its engineering and maintenance labor and materials costs for future filings.

On cross-examination, witness Chamberlin stated that while he recommended that CP&L use Duke's $2.68/kW estimate for fixed O&M instead of its own $0.66/kW estimate, he did not recommend that CP&L use Duke's $379/kW estimate for fixed capital cost of CTs instead of its own $431/kW estimate. He maintained that using Duke's estimate for O&M costs but not for capital costs was fair.

CP&L contended that it would be inconsistent to use Duke's estimate for O&M expense and not use Duke's estimate for capital cost. CP&L pointed out that its estimate for capital cost of a CT was also based on EPRI's TAG data.

The Commission is aware of the considerable uncertainty associated with estimating future costs. Until such costs are known with relative certainty, a reasonable approach is to use an industry planning guide such as EPRI's TAG data. Consistency is also important in such estimates and the Commission notes that

CP&L used the TAG data for capital as well as fixed O&M cost estimates. The Commission concurs with the consistent approach taken by CP&L and concludes that its fixed O&M costs should be accepted for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding of fact is contained in the testimony of CP&L witness King and Public Staff witness Chamberlin.

Witness Chamberlin pointed out that CP&L's proposed avoided capacity cost now included only fixed O&M costs whereas it had also included variable O&M costs in the previous biennial proceeding. CP&L now proposes to include all variable O&M expenses in the energy credits instead of in the capacity credits.

The Commission is of the opinion that CP&L's proposal to include variable O&M expenses in the energy credits instead of in the capacity credits is reasonable. The proposal is uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16 AND 17

The evidence for this finding of fact is contained in the testimony of Duke witness Freund and Public Staff witness Chamberlin.

Witness Freund testified that Duke's capacity credits were based on the projected costs of new combustion turbines. Duke used a cost under an existing contract for CTs to be added through 1988, and a cost developed by Duke's engineering department for CTs built after 1988.

Witness Chamberlin testified that Duke should use only its known capital costs, namely the $379/kW in 1991 dollars for CTs added from 1991-1998 based on Duke's contract with General Electric for up to 16 CTs in the 1994-1999 time frame. He admitted through cross-examination that he would have accepted the entire estimate if he had confidence it was a thoroughly developed estimate.

The Commission concludes that Duke's entire estimate of the costs of new CTs should be adopted. Witness Chamberlin conceded that he had not done an engineering cost estimate of his own, and that it would be appropriate for Duke to use such an estimate if it thought the estimate was a better one than the GE contract.

Witness Freund testified that the capacity credit included a provision for the cost of overhauling CTs. He explained that the capacity credit is paid on a ¢ per kW basis, which allows the overhaul cost to be paid on a variable basis.

Witness Chamberlin testified that overhaul costs are an appropriate component of avoided costs, but he contended that they should be included with variable O&M expenses rather than with fixed O&M expenses. He reasoned that overhaul costs are a function of the running time or hours of operation of a CT.

The Commission concludes that Duke should be allowed to include overhaul costs in its fixed O&M expenses as proposed for purposes of this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

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

Witness Chamberlin testified that Duke should levelize its variable energy rates over two years (1991 and 1992) in a manner consistent with CP&L's filing. Witness Freund testified that he did not strongly oppose witness Chamberlin's recommendation, but noted that Duke's present method offers the advantage of only having to project avoided energy costs one year out, thus eliminating some of the uncertainty. He noted that an annual fuel charge adjustment would not be applicable under the two-year levelized energy rate.

The Commission finds and concludes that Duke should levelize its variable energy rate over two years in a manner consistent with CP&L's filing.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 AND 20

The evidence for this finding of fact is contained in the testimony of Duke witness Keels and CP&L witness King.

Witness Keels testified that Duke is proposing numerous changes to its Standard Purchased Power Agreement and to the terms and conditions of Schedule PP(NC). One change is Duke's proposed addition of Paragraph 1.4 to its Standard Purchase Power Agreement. He testified that the paragraph has been added to further incorporate in the contract the concept of a "Capacity Commitment" by the supplier. The previous standard contract language only spoke to the "maximum amount of electric power to be delivered" by the Supplier. Capacity and energy payments are made to the QF on the premise that the generating capacity provided by the QF allows Duke to truly avoid capacity and energy costs throughout the term of the Agreement. Therefore, the contract should specify the amount of capacity the QF commits to deliver to the Company throughout the term of the Agreement. This value can then be used by Duke's planners as a representation of the capacity the Company avoids by the presence of the QF. The capacity commitment provision is especially important with cogeneration facilities which may be able to market their steam output to increase their profits and can therefore effect the electric capacity provided to Duke.

The Public Staff raised a concern that the proposed paragraph could be interpreted to provide for a penalty in the form of no capacity payment when a QF delivers reduced capacity. The Public Staff concedes that the proposed paragraph may be appropriate in negotiated contracts with larger QFs.

The Public Staff cited the testimony of CP&L witness King, who testified that CP&L pays a capacity credit based on the on-peak kWh supplied by the QF. When a QF falls below the amount designated in the contract (which for CP&L is the normal maximum dependable capacity), it is not penalized by having its capacity credit reduced. It is simply paid the on-peak capacity credit times the number of kWh it actually generates.

The Public Staff contends that changing the language of Duke's standard contract to better identify the amount of capacity the QF will actually provide should prove to be beneficial for planning purposes, but that such a commitment should not then be used to reduce payments to the QF. It contends that each QF should be paid for the amount of capacity delivered regardless of whether it is above or below the designated amount.

Duke contends that QFs which have negotiated contracts will be expected to abide by the capacity commitments contained in their contracts. This would include both large QFs and small QFs. Duke also points out that it will pay for capacity actually delivered by the QF regardless of whether it is above or below the QF's capacity commitment, provided the QF has not negotiated a contract.

The Commission concludes that the proposed addition of paragraph 1.4 should be approved, and that such language should not be used to reduce capacity payments paid to QFs for delivery of capacity pursuant to Schedule PP(NC) under the Standard Purchased Power Agreement without specific approval of this Commission.

Another change Duke proposes to its Standard Purchased Power Agreement is its proposed addition of paragraph 9. Paragraph 9 would specify that the Interconnection Facilities Charge becomes due when the interconnection facilities become operational, regardless of whether or not deliveries of power has begun.

The Public Staff raised a concern that if delivery of power is delayed for causes considered legitimate under the terms of the standard contract, the QF could still be charged the Interconnection Facilities Charge pursuant to paragraph 9. The charge is usually substantial and could pose a significant burden to small QFs.

Duke contends that the date when an interconnection facility becomes operational is specified by the QF beforehand and that Duke attempts to comply with the specified date as nearly as possible. The specified date is necessarily prior to the initial power delivery date because the QF must integrate its own equipment with the interconnection facility and perform testing prior to beginning delivery of power.

The Commission concludes that the proposed addition of paragraph 9 should not be approved in this proceeding. Duke can petition the Commission for recovery of interconnection facilities charges on a case by case basis when the length and circumstances of delay in power delivery seem to warrant such relief.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

Public Staff witness Chamberlin recommended in his testimony that the "Reserve Margin Adjustment" currently included in avoided capacity cost calculations for Duke and CP&L should be renamed the "Performance Adjustment" in order to avoid confusion. The recommendation was uncontested and the Commission concludes that it should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 22

The evidence supporting this finding is found in the testimony of Duke witness Freund and Public Staff witness Chamberlin.

Public Staff witness Chamberlin testified that capacity credits are currently paid to QFs on a ¢/kWh basis spread over all on-peak hours of the year. In the case of CP&L, for example, this means that a QF needs to be on line and producing power for 3,036 hours a year in order to receive capacity credits equal to the total capacity cost. Witness Chamberlin testified that the payment method renders certain types of QF projects uneconomic, including those with low capital costs but high operating costs which exceed the adopted avoided energy credits. These plants could provide valuable peaking capacity to the utility if allowed to operate like a peaking unit (i.e., at a much lower number of hours per year).

To ensure that these types of projects are not discouraged, witness Chamberlin recommended that a payment option be included in CP&L's Schedule CSP and in Duke's Schedule PP(NC) that compensates QFs on a $ per kW basis if certain operating criteria are met. Payments would be made under this option only if QFs could show that they stood ready and able to generate power during each utility's critical on-peak hours.

Duke witness Freund testified that a fixed capacity credit could be provided, but that in his opinion it would be a more complex arrangement than currently exists. He stated that some sort of performance standards would be required with that type of pricing scheme. Witness Freund stated he was not aware of much interest in peaking arrangements with QFs but if there was, it could be addressed through negotiations.

On cross-examination, witness Chamberlin indicated that the willingness of the utilities to negotiate a $ per kW rate with a QF on a case by case basis would satisfy his concern about pricing capacity credits to peaking units.

The Commission is of the opinion that it would be premature to require that Duke and CP&L each offer a tariff containing a capacity payment option based on $ per kW. No direct testimony on the subject was presented by CP&L, and the Public Staff witness indicated that his concerns might be satisfied by something less than a specific tariff. Furthermore, there was little discussion as to the operating criteria that must be met if such a capacity payment option were to be offered. Therefore, the Commission concludes that the affected parties should file further comments on the subject in this docket, and that the Commission will make a determination at a later date after reviewing the comments of the parties.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 23

The evidence in support of this finding of fact is contained in the testimony of NC Power witness Green and Public Staff witness Chamberlin.

NC Power uses the DRR method to determine avoided costs. The avoided costs developed pursuant to NC Power's application of the DRR methodology represent the amount NC Power's customers should be willing to pay for nonutility generation. The calculated avoided cost should result in customer indifference as to whether the capacity is supplied by QFs or from NC Power facilities. NC Power has applied the DRR method in a manner which achieves this objective and adequately calculates total avoided costs.

Public Staff witness Chamberlin indicated that, while the DRR method provides reasonable total avoided costs, it does not provide an accurate split between capacity and energy costs. He recommended that NC Power investigate alternative ways of dividing energy and capacity costs within the DRR framework. The method best suited to the NC Power system should then be used to calculate avoided costs in the next biennial filing.

The Commission recognizes the potential limitation of the ORR methodology as applied by NC Power and finds that the Company should investigate alternative ways of dividing energy and capacity costs within the ORR framework in order to determine if a more accurate split between capacity costs and energy costs can be made. The Company's investigation should include the applicability of a third PROMOD run as suggested by witness Chamberlin. The method NC Power finds best suited to its system should be used to calculate avoided costs in the next biennial filing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence in support of this finding is contained in the testimony of NC Power witness Green and Public Staff witness Chamberlin.

The DRR methodology applied by NC Power requires the Company to develop a base case without an additional increment of QF generation. The Company then develops an alternative case which includes a 200 mW block of QF capacity at zero cost. The 200 mW block of QF capacity is modelled on a must run basis and thereby displaces an equivalent amount of base case generation. The cost difference between the base or "without QF" case and the alternative or "with QF" case is used to determine avoided costs.

NC Power models QF generation at a 100% equivalent availability level. NC Power's units are modelled at their expected equivalent availabilities which incorporate assumed forced outage rates and annual maintenance schedules. The Company's generating units are thereby modelled at an equivalent availability of less than 100%.

NC Power contended that its calculation methodology permits a QF to be appropriately compensated for a level of generation in excess of a corresponding utility unit of similar size. It believes that the additional compensation paid to a QF as a result of the modelling techniques inherent in the DRR methodology is roughly equivalent to the 20% "performance adjustment" applied by Duke and CP&L to their capacity payments. However, NC Power does not apply the performance adjustment in the calculation of its Schedule 19 rates.

Public Staff witness Chamberlin contended that there is no way to be certain that the results of the DRR methodology are comparable to the 20% performance adjustment applied by Duke and CP&L in their peaker methodology. He contended that NC Power should study its method of calculating capacity costs in order to determine if its capacity credits should include a 20% performance adjustment.

For these reasons, the applicability of a performance adjustment to NC Power's capacity credits should be investigated prior to the Company's next biennial avoided cost filing. A performance adjustment should be incorporated into those rates if it is found to be appropriate. However, a performance adjustment should not be applied to NC Power's rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 25

The evidence in support of this finding is contained in the testimony of NC Power witness Newcomb and Public Staff witness Chamberlin.

NC Power's Schedule 19 rates are developed under the assumption that there are 3,000 on-peak hours in a year. The Company developed rates which allow the QF to receive its full annual capacity payment if the QF maintains an 80% on-peak capacity factor. This was achieved by dividing the total capacity payment by 3,120 hours (80% x 3900 on-peak hours) and then applying the capacity payment only to the first 3,120 on-peak hours of equivalent full power-operation.

Public Staff witness Chamberlin indicated that the calculation of capacity payments on the basis of 3120 hours and the subsequent application of payments to a maximum of 3120 hours may be a limiting factor upon the rates of North Carolina Power and may be inconsistent with the application of the 20% performance adjustment by Duke and CP&L.

Accordingly, the Company should continue to calculate and apply its capacity credit on the basis of 3120 hours for purposes of this proceeding. However, the Company should analyze the differences associated with the consistent calculation and application of capacity credits on the basis of both 3120 and 3900 hours and the potential limitations raised by Witness Chamberlin. The results of that investigation should be filed with the Company's next biennial avoided cost filing and incorporated in the Company's future calculations, if appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 26

The evidence in support of this finding is contained in the testimony of North Carolina Power witnesses Newcomb and Carney and Public Staff witness Chamberlin.

NC Power proposed a new Paragraph V(H) to its Schedule 19 terms and conditions which permits the Company to dispatch a QF during periods of light system loads, up to a maximum of 1000 off-peak hours per calendar year. The stated purpose of this provision is to permit the Company to avoid the downward dispatch of its low cost nuclear units during light load conditions, thereby permitting the Company sufficient operating flexibility in maintaining a least cost production system.

Public Staff witness Chamberlin acknowledged that the Company needs the right to dispatch deliveries from QFs in order to avoid incurring unnecessary costs during light load conditions, but he indicated that QFs should be protected by contract language that clearly spells out the criteria for curtailing deliveries.

NC Power Witness Carney asserted that the concept proposed by witness Chamberlin would limit NC Power's reduction of power purchases to those times when four specific criteria are strictly met. Witness Carney indicated that reductions in power purchases must be anticipated and often require the judgment of a utility's system operator. However, a requirement that the utility meet the four specific criteria prior to initiating purchase power reductions removes the element of judgment from the system operator. Purchase power reduction decisions would have to be instantaneous in order to be effective. The concept of specific detailed purchase power reduction criteria proposed by witness Chamberlin would therefore limit the ability of the utility to provide NUGs with advance notice, which is necessary for orderly generation reductions or shutdowns.

Witness Chamberlin testified on cross-examination that he did not have any specific concerns about NC Power's intent, but he was concerned that when capacity payments are paid to a QF on an energy basis, curtailment of the QF might keep it from receiving the value of its capacity in a particular year. He indicated that witness Carney's suggestion in his rebuttal testimony that some discretion and judgment must be exercised when loads are near the four criteria did not pose a problem for him.

The Commission has reviewed the discussion of the witnesses in this matter, and is still not satisfied with the evidence as presented. There seemed to be a good deal of uncertainty as to what should be done about this issue. The Commission notes that the NC Power proposal has been adopted by the Virginia PUC, and it is interested in knowing what the experience will be in Virginia under the proposal. The Commission is of the opinion that NC Power should monitor the experience of QFs under its proposal in Virginia and bring the matter back to the North Carolina Commission in the next biennial proceeding. Therefore, the Commission concludes that the proposal by NC Power to reduce power purchases from a QF during light load conditions is not appropriate in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 27

The evidence in support of this finding is contained in the testimony of NC Power witness Newcomb.

NC Power has proposed a non-time differentiated energy payment to QFs with generation facilities rated at 100 kW or less. The non-time differentiated option allows small QFs to sell relatively small quantities of electricity to the Company without incurring the more significant costs associated with time differentiated metering equipment and processing requirements. The opportunity for inappropriate applications of the rate and for overpayments to QFs is relatively insignificant with regard to the application of non-time differentiated rates to small QFs. Furthermore, the additional costs of time differentiated metering are relatively insignificant for large QFs which, combined with the potential for significant overpayments to large QFs, outweighs the need to provide for non-time differentiated energy payments to larger QFs.

The proposed non-time-differentiated energy payment was unopposed by any party, and the Commission concludes that it is reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 28

The evidence in support of this finding is contained in the testimony of North Carolina Power witness Newcomb.

The most significant difference between North Carolina Power's previous Schedules 19 and 19H involves the payment method for capacity. Previous Schedule 19H provided for a levelized capacity price for the term of the contract while previous Schedule 19 provided for escalating capacity prices at a fixed percentage for each year. NC Power's proposed Schedule 19 replaces the method of escalating capacity prices contained in previous Schedule 19 with the levelized capacity price matrix formerly found in Schedule 19H. The need for a separate Schedule 19H has been eliminated and the Company has proposed its withdrawal. No party opposed the modification of Schedule 19 or the withdrawal of Schedule 19H. The Commission finds that it is appropriate for NC Power to eliminate Schedule 19H.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence pertaining to Nantahala's calculations of avoided cost rates is contained in the testimony of Nantahala's witness Tucker, which was stipulated into the record without witness Tucker being called to the stand. According to his prefiled testimony, the rates in Nantahala's proposed Schedule CG differ from the standard rates currently approved by the Commission. The rates previously approved were based on the Interconnection Agreement between TVA and Nantahala. The Schedule CG proposed in this proceeding is designed to reflect the actual avoided cost resulting from Nantahala's new power supply arrangement with Duke Power. Since purchases of capacity and energy by Nantahala from qualifying facilities would generally reduce what Nantahala would otherwise purchase from Duke under the interconnection agreement between Nantahala and Duke, the amounts which Nantahala proposes to pay to qualifying facilities for capacity and energy sold to Nantahala are geared to the cost savings under that agreement.

The Commission notes that no other party to this proceeding presented an evaluation or took issue with Nantahala's proposed rate schedule or purchase power agreement, and concludes that they should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 30

The evidence pertaining to WCU's calculation of avoided costs is contained in the testimony and exhibits of WCU witness Wooten, which were stipulated into the record without witness Wooten being called to the stand. WCU does not generate its own electricity but buys its power wholesale from Nantahala Power and Light Company at rates approved by the FERC. The avoided cost formula proposed by WCU would reimburse a qualifying facility based on the rates charged to WCU by Nantahala at any point in time, and is the same formula approved by the Commission in previous proceedings. No party challenged the avoided cost formula proposed by WCU. The Commission concludes that the proposed Small Power Production Supplier Reimbursement Formula should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 31

The evidence in support of this finding is contained in the testimony of CP&L witness King, Duke witnesses Freund and Keels, NC Power witnesses Newcomb, Green and Carney, and Public Staff witness Chamberlin.

The evidence and conclusions for this finding are cumulative and are reflected in the foregoing findings and conclusions. The rate schedules, contracts and terms and conditions proposed by the three major utilities in this proceeding are generally reasonable except as discussed herein, and they should be approved subject to the modifications discussed herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 32

The evidence for this finding of fact is contained in the testimony of Public Staff witness Chamberlin, Duke witness Keels, CP&L witness King, and five public witnesses.

Witness Chamberlin testified that most of the QF development in CP&L's territory occurred in the mid-1980's and the last contract between CP&L and a QF was executed in November of 1987. He further testified that while Duke has entered into several QF contracts in recent years, Duke has fewer mW of QF capacity on-line than CP&L.

Witness Keels testified that Duke has 56 QF facilities on line representing approximately 360 mW, and that it has contracts with another 31 facilities that have a generating capacity of 102.8 megawatts. Nineteen of these projects, representing 84 mW of capacity, are in North Carolina. Fourteen of the seventeen projects on Schedule PP(NC), are hydroelectric facilities, one is municipal solid waste, one is landfill gas, and one is coal-fired. One of the other two projects is on Schedule PG, which provides for excess sales, and the other is on a negotiated rate. Witness Keels further testified that five mWs of the 13.5 mWs added in 1990 came from the renegotiation of R.J. Reynold's expired five-year contract. He testified on cross-examination that most of the 20 mWs of increased nameplate capacity nearing completion in early 1991 would be used internally.

CP&L witness King testified that CP&L has 37 QF contracts in place and approximately 410 mW of QF capacity. He indicated that contract discussions are ongoing with another ten or so QFs and IPPs.

Public Staff witness Chamberlin recommended that the Commission monitor the low level of QF contract activity by Duke and CP&L in order to determine if corrective action was needed. He acknowledged on cross-examination that the utilities are required to file periodic reports of QF activity with the Commission and to participate in formal proceedings to review their various resource options.

Steve Cook, owner and operator of High Falls Plant, testified regarding his experience with hydroelectric generation. He testified with respect to the safety and environmental benefits of hydroelectric generation and stated that it ought to be developed to its maximum potential all over the country. He pointed out that it is quiet, does not have smokestacks and does not hurt anything. He discussed his involvement with two operational facilities and one that is under consideration, and with projects owned by others on which he had worked. He said his experience involved enough plants to have a good overview of what rates are required. He testified that the 6.8¢ rate works in small hydro and that the 4¢ rate proposed by CP&L will not work. He cited for example the Steele's Mill plant which has a 5.2¢ or a 5.6¢ rate. It has failed and is being sold.

Witness Cook suggested that there was insufficient consideration given to anything besides fuel costs in the avoided cost rates, which are "way out in left field" because nuclear fuel waste disposal costs are not fully considered. He further testified that a 6.8¢ rate is the only hope we have got for the future, if in fact everyone wants to promote hydro and take advantage of a renewable resource.

Lynwood Bullock, the owner and operator of Cedar Falls Plant on Deep River in North Carolina, testified concerning his experience with receiving a lower rate than he anticipated and being held up by NRCD. He testified that if he had borrowed money, his project would have failed. His concern was grounded mainly in the fact that avoided costs have gone down and continue to go down, while all other costs are going up. He requested that the Commission look into the matter.

Tim Henderson, developer of two potential hydroelectric facilities on Mayo River in Rockingham County, testified as to the direct impact of the rates on the efficiency and viability of the development of hydro plants. He testified that he knew of licenses on two substantial plants that had been turned in because they became uneconomical when the last rate decrease was approved.

Charles Wood, involved in development of two potential hydroelectric projects on Mayo River in Rockingham County, testified that any further reduction in rates makes his project infeasible. He is taking a gamble but he is doing it because he feels strongly about what the hydroelectric developers are doing and that the contribution is very valuable to the environment. He further testified that he didn't see how avoided costs could go down when three to five percent inflation continues to exist in our economy.

Joe R. Ellen, Jr., the owner and operator of Rocky River Power Plant, testified about his relationship with CP&L as the first hydroelectric QF on CP&L's system. He testified about the effect of the continuing decreases in the variable rate, and contended that he had been told at the outset how he could anticipate that over 15 years his income under the variable rate would be the same as if he opted for the levelized fixed rate. At that time, CP&L had already petitioned the Commission to lower the variable rate and it has been lowered every time since. He further testified that if the downward trend for alternative energy contracts was allowed to continue, the purpose of PURPA will be defeated and we are going to have a disaster for the small producer.

Witness King testified that CP&L's avoided cost rates were declining primarily because fuel costs are going down. He suggested as an example that the price of oil in real dollars, adjusted for inflation, might now be lower than it has been since World War II.

CUCA offered no evidence but attempted to establish through cross-examination that declining avoided cost rates was the cause of decreased QF activity as well as a hinderance to the economic feasibility of existing and future developments. During cross-examination by CUCA, Public Staff witness Chamberlin testified that declining rates had some effect on the decrease in QF activity, but that there were additional reasons. Witness Chamberlin cited exhaustion of the resource itself, procedural issues that could be raised in contracting for that kind of power, and various perceptions over what the market was going to look like in the future as opposed to what it looks like now.

The Commission is of the opinion that the issue before it in this proceeding is the identification of each utilities' appropriate avoided costs, not the rate level necessary to make QF projects economically feasible for developers. The Commission has required that certain rate options be made available to small QFs in order to encourage such development. However, fairness requires that the various opportunities opened to small QFs not necessitate a subsidy by other ratepayers.

The Commission is further of the opinion that the Public Staff should continue to monitor the QF contract activity of each utility discussed herein in order to ensure that avoided cost rates and contract activities are consistent with least cost integrated resource planning activities. The Commission currently has procedures in place for monitoring such activity. All utilities are required to file annual status reports of QF activity in their respective service areas. Avoided cost hearings are held biennially and least cost integrated resource planning hearings are held every two or three years.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 33

The Public Staff's Motion To Amend Rule R1-37 and its Motion To Amend Contents of Status Reports are decided by separate orders in this docket.

IT IS, THEREFORE, ORDERED as follows:

1. That CP&L and Duke shall offer long-term levelized capacity payments and energy payments for 5-year, 10-year, and 15-year periods as standard options to qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power producers as that term is defined in G.S. 62-3(27a) or (b) any other qualifying facility contracting to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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.

2. That NC Power shall offer long-term levelized capacity payments with 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 qualifying facilities which are either (a) hydroelectric generating facilities of 80 megawatts or less capacity which are owned or operated by small power

producers as that term is defined in G.S. § 62-3(27a) or (b) any other qualifying facility which contracts to sell generating capacity of five megawatts or less. The standard levelized rate options of 10 or more 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.

3. That NC Power shall develop and offer a fixed long-term levelized energy payment as an additional option for small QFs rated at 100 kW or less.

4. That Duke and CP&L shall offer nonhydroelectric qualifying facilities contracting to sell generating capacities of more than five megawatts the options of contracts at the variable rates set by the Commission or contracts at negotiated rates and terms.

5. That nonhydroelectric qualifying facilities of more than five megawatts of capacity desiring to sell generating capacity to NC Power shall participate in its competitive bidding process for obtaining additional capacity.

6. That Nantahala and WCU shall not be required to offer any long-term levelized rate options to qualifying facilities.

7. That the rate schedules, contracts and terms and conditions proposed in this proceeding by CP&L, Nantahala and WCU are hereby approved.

8. That the rate schedules, contracts and terms and conditions proposed in this proceeding by Duke and NC Power are hereby approved, subject to the modifications discussed herein.

9. That CP&L, Duke, NC Power, Nantahala and WCU shall file within 10 days after the date of this Order rate schedules, contracts, and terms and conditions implementing the findings, conclusions and ordering paragraphs discussed herein.

10. That NC Power shall study its DRR methodology in order to determine whether a more accurate split between capacity costs and energy costs can be made. Its findings and solutions shall be presented in the next biennial proceeding.

11. That NC Power shall study its method of calculating capacity costs in order to determine if its capacity credits should include a 20% performance adjustment. Its analysis shall be presented in the next biennial proceeding.

12. That NC Power shall study its practice of calculating capacity payments on the basis of 3120 hours and subsequently applying such capacity payments to a maximum of 3120 hours in order to determine whether its practice is consistent with application of a 20% performance adjustment. Its analysis shall be presented in the next biennial proceeding.

13. That CP&L, Duke, the Public Staff and any other interested party shall file comments with the Commission within 30 days after the date of this Order containing further discussion of the proposal for Duke and CP&L to develop capacity credits to small QFs for peaking-type resources on a $ per kW basis in addition to their capacity credits on a ¢ per kWh basis as discussed herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-100, SUB 22

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Rulemaking Proceeding and Investigation) into the Feasibility of Increase the) Supply of Natural Gas in the State of) North Carolina)	ORDER REVISING REQUIREMENTS OF NCUC RULE R1-17(h)(8)

BY THE COMMISSION: On June 26, 1975, the Commission established procedures for the participation by the natural gas local distribution companies in exploration and drilling (E&D) programs and for making changes in rates to recover the costs and to account for the revenues associated with those programs. These procedures are codified in NCUC Rule R1-17(h). Subsection (8) of the rule currently requires each natural gas local distribution company to file on or before March 1 and September 1 of each year an accounting of all revenues realized from Commission-approved E&D programs during the six-month period ending the preceding December 31 and June 30, respectively, along with a plan for distributing those revenues and a true-up of any over- and under-distributions.

On June 17, 1991, the Public Staff advised the Commission at its Regular Staff Conference that, after reviewing recent E&D filings, the Public Staff has come to the conclusion that semi-annual refunds are no longer necessary given current levels of participation in E&D programs and associated revenues. The Public Staff stated that customers will be protected by the accrual of interest on unrefunded revenues, and the Public Staff will have sufficient information to monitor the programs, if the accountings and refund plans are required to be submitted once a year. The Public Staff also stated that it had discussed a rule change to this effect with each of the gas companies, the Attorney General, and the Carolina Utility Customers Association, Inc. (CUCA), and those parties do not object to such a change.

Upon consideration of the foregoing, the Commission is of the opinion, and so concludes, that unless protests are received, the accounting, refund, and true-up of E&D revenues pursuant to NCUC Rule R1-17(h)(8) should occur annually, on or before March 1, of each year, until further Order.

IT IS, THEREFORE, ORDERED as follows:

1. That until further Order of the Commission, the accounting, refund, and true-up of revenues associated with the Commission-approved exploration and drilling programs pursuant to NCUC Rule R1-17(h)(8) shall occur annually, on or before March 1 of each year.

2. That the Chief Clerk shall serve a copy of this Order on the Attorney General, Carolina Utility Customers Association, Inc., Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., North Carolina

Natural Gas Corporation, and North Carolina Gas. If any party objects to the revised procedures set forth in this Order, a protest shall be filed not later than July 5, 1991.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-100, SUB 48

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Public Service Company of North Carolina for Amendment of NCUC Rule R6-19.2(f) and (g)	) ORDER ON REOPENED) RULEMAKING PROCEEDING

BY THE COMMISSION: On April 4, 1988, the Commission issued an Order in this docket amending Commission Rule R6-19.2(f) to provide as follows:

> (f) During July and August of each year, consumption for each customer for the twelve-months ending June 30 of such year shall be reviewed. If it is found that the customer has either increased or decreased his annual consumption based on the two prior years' consumption to the point it would place him on a different rate schedule, the customer shall be automatically reclassified to the proper rate schedule effective the following September 1. In determining consumption, periods of involuntary curtailment shall be excluded.

Each customer reclassified under this rule shall be notified of the change in rate schedule, along with a copy of the tariff sheets applicable to his old and new rate schedule, at least twenty-one days prior to the effective date of the change. If the customer, within fourteen days of being notified that a rate change is pending, files appropriate documentation showing that any decline in usage during the updated base period was due to alternate fuel usage, the company shall allow the customer to remain on his original rate schedule.

On August 10, 1990, the Public Staff filed its Motion to Reopen Docket asserting that three complaint proceedings have been filed with the Commission concerning the manner in which the LDCs are implementing Rule R6-19.2(f), that these complaints indicate that the LDCs are using different methods to determine whether customers should be put on new rate schedules according to the Rule, that there do not appear to be any evidentiary disputes in these complaints proceedings other than the proper method for implementing the Rule, and that the Commission should reopen this rulemaking proceeding--and consolidate the complaint proceedings with it--in order to hear oral argument on the proper method for implementing the Rule.

On September 19, 1990, the Commission issued its Order Reopening Rulemaking Proceeding in this docket. By that Order, the Commission reopened this docket for the purpose of considering the proper method for implementing Rule R6-19.2(f), and the Commission scheduled an oral argument. The Commission further provided that proceedings on the three complaint dockets cited by the Public Staff be suspended and that those complainants be afforded an opportunity to intervene and participate in the present docket. The three complainants were allowed to intervene by Commission Order of October 17, 1990.

Oral argument was held as scheduled on October 29, 1990. The oral argument revealed substantial agreement on several issues. For example, the three LDCs--Piedmont, Public Service and NCNG--agreed on a common method for implementing Rule R6-19.2(f) in the future. The Commission ordered that Public Service submit a late-filed exhibit setting forth this methodology in detail and that other parties be allowed to file comments.

Following the oral argument, Public Service filed Supplemental Comments on November 8, 1990, setting forth the methodology proposed by the LDCs for implementing Rule R6-19.2(f). Reply comments were filed by NCNG on November 26, 1990, and by the Public Staff on November 29, 1990. Further comments and responses were filed by Public Service and CUCA on December 12, 1990, and by Piedmont on December 31, 1990.

The Commission has carefully weighed and considered all of the comments and exhibits presented herein. The Commission commends the parties for their efforts and their agreement on several issues presented by this reopened rulemaking proceeding.

This rulemaking proceedings was reopened to consider the method for implementing Rule R6-19.2(f), which requires that the LDCs review each customer's consumption of natural gas annually and automatically reclassify a customer to the proper rate schedule "[i]f it is found that the customer has either increased or decreased his annual consumption based on the two prior years' consumption to the point it would place him on a different rate schedule . . . . In determining consumption, periods of involuntary curtailment shall be excluded."

Public Service presented several points during oral argument on which there was agreement. First, Public Service proposed that the existing Rule R6-19.2(f) be moved and renumbered as Rule R6-12(7). Public Service explained that although the existing Rule R6-19.2(f) deals with reclassification of rate schedules, it appears in the rule dealing with curtailment priorities. This has created confusion and Public Service proposed that the existing Rule R6-19.2(f) be moved and renumbered. Second, Public Service proposed that a new rule be drafted and numbered Rule R6-19.2(f). The Commission has ordered LDCs to continue to monitor customers' usage by priority and to file reports based on priorities. Thus, the LDCs must continue to assign priorities to customers and to revise customers' priorities as they change based upon consumption. The new Rule R6-19.2(f) will provide for updating customers' priorities. Third, Public Service reported that the LDCs have agreed that in the future they will use the same methodology for computing consumption under both the new rule dealing with rate schedules, Rule R6-12(7), and the new rule dealing with priorities, Rule R6-19.2(f). Public Service has prepared a detailed statement of this methodology and a narrative describing how it operates. These were filed as a part of Public Service's Supplemental Comments of November 8, 1990. Both CUCA and the Public Staff agreed with this methodology. There was agreement at the oral argument that this methodology need not be set out in the Commission's Rules, but that it should be incorporated in each LDC's own rules and regulations.

On the basis of the comments and exhibits and the agreement thereon, the Commission finds good cause to order that the present version of Rule R6-19.2(f) be moved and renumbered as Rule R6-12(7), that a new section dealing with reclassification of customers' priorities be written and numbered Rule R6-19.2(f), that the LDCs use the methodology attached to Public Service's Supplemental Comments of November 8, 1990, for implementing both the new Rule R6-12(7) and the new Rule R6-19.2(f), and that the statement of the methodology provided by Public Service (but not the narrative of the methodology) be incorporated in each LDC's rules and regulations. The new Rules are attached to this Order as Appendix A hereto. The LDCs shall within 10 days file revised rules and regulations with the Commission incorporating the methodology ordered herein. The LDCs shall also mail notice of the new Rule R6-12(7) and the methodology to implement it to their industrial customers who are most likely to be affected.

The Commission notes one exception to the methodology agreed upon by the LDCs. The Public Staff urged that an exception be made if a customer adds new gas-burning equipment so that the customer will not have to wait two full years in order for his increased consumption to entitled him to a rate change. CUCA supported this exception. Public Service agreed with the concept. Piedmont did not object so long as a corresponding exception is made for customers who remove equipment and thus decrease consumption on an ongoing basis. The Commission finds the exception to be appropriate. The exception need not be written into the methodology which deals with the required annual review, but it should be observed in practice on the basis of this Order. The exception should be recognized for the addition, or retirement, of major pieces of gas-burning equipment that will clearly increase, or decrease, the customer's consumption on an ongoing basis to a level that will qualify the customer for a different rate schedule. The customer must report the matter to the utility and the utility must have an opportunity to inspect and to meet with the customer to review and discuss the anticipated future level of consumption. The reclassification should occur within two months after the new equipment is in place and operational, or the retirement is completed, and the first meter reading reflects the higher anticipated usage resulting from the new equipment, or the lower anticipated usage resulting from the retirement. A reclassification pursuant to this exception should be subject to correction if actual experience so warrants.

Public Service also proposed at oral argument that the last sentence of the new Rule R6-12(7) be eliminated and that no comparable provision be incorporated in the new Rule R6-19.2(f). This proposal provoked disagreement. The sentence in question provides that if a customer who would otherwise be reclassified to a higher rate schedule based upon a drop in consumption can show that the reduced consumption was caused by the customer's use of alternate fuel, the customer's rate schedule will not be changed. Both Public Service and Piedmont argued that if a customer voluntarily decides to use an alternate fuel because it is cheaper than natural gas, and the customer thereby cuts his natural gas consumption to the point where it would place him on a higher rate schedule under the availability provisions of the rate schedules, the customer should pay that higher rate. NCNG took no position on eliminating the sentence. The Public Staff found elimination of the sentence to be reasonable. CUCA urged the Commission to retain the sentence. CUCA argued that eliminating the sentence will penalize customers who decide to use cheaper alternate fuel, that it will encourage wasteful energy usage (since it will encourage customers to use natural gas even if gas costs more than alternate fuels), and that it will impair the competitiveness of our State's industries.

The Commission finds good cause to eliminate the sentence. It is a basic aspect of natural gas rate design that the availability of rate schedules often depends upon the customer's level of consumption. This sentence tends to allow a customer to reduce his level of consumption voluntarily and yet still remain on a rate schedule requiring a higher level of consumption. While we agree that periods of involuntary curtailment should be eliminated in computing consumption levels, we do not believe that a customer should be allowed to retain a rate schedule lower than the one to which his voluntary level of natural gas consumption entitles him under the rate design approved by the Commission. We have carefully considered CUCA's arguments. We do not view elimination of the sentence as penalizing any customer. Rather, retaining the sentence would tend to reward some customers with a lower rate than that provided by the Commission's rate design. We do not believe that our decision encourages wasteful energy usage or impairs our State's competitiveness. We have no doubt that our State's industries will employ the least expensive energy options available. Our decision merely requires that they consider the effect of our natural gas rate design in making their decisions on alternate fuel usage.

The new Rule R6-12(7) provides that customers who are reclassified "shall be notified of the change in rate schedule, along with a copy of the tariff sheets applicable to his old and new rate schedules at least 21 days prior to the effective date of the change." CUCA urged that any customer reclassified to a new rate schedule be notified by registered or certified mail, return receipt requested, and that the new rate schedule be either stayed or charged subject to refund while the customer has a chance to contest it. Intervenor complainant Sapona urged a personal visit by a utility representative to be sure that the notice is understood. The Commission agrees that it is appropriate to mail the notice by either registered or certified mail, return receipt requested, 21 days in advance. We see no need to stay a reclassification that is questioned by a customer; however, it should be clear that any reclassification found to be improper will be corrected and that retroactive billing adjustments, if appropriate, will be made.

The new methodology that the LDCs have agreed to use in the future is essentially the same as that used by NCNG in the past. Public Service and Piedmont used different methodologies in the past. Complaint cases have been filed with the Commission which turn on the propriety of the various methods used by the LDCs. The Public Staff has asked us to consider the effect of our present decision, which establishes one method for all LDCs to use in the future, on the different methods which the LDCs used in the past. More specifically, the Public Staff asserted that given the "ambiguity and vagueness" of our past rule on reclassification, the Public Staff does not believe that any of the methods used by the gas companies violated the rule. The Public Staff would have the Commission clarify our intent by stating that past methods of calculating customer usage for purposes of reclassification "were not improper" except where a utility (Public Service) adopted more than one method and unilaterally changed reclassification methods from time to time. Public Service responded that the propriety of its changes in reclassification methods can only be decided on a case-by-case basis. One complaint case dealing with the Public Service situation (Eaton Corporation vs. Public Service, Docket No. G-5, Sub 270) has already been heard by a Commission Hearing Examiner.

The Commission recognizes that three complaint cases dealing with the propriety of the methods used by the LDCs in the past have been suspended pending this rulemaking proceeding. Those complaint cases have not been consolidated with this rulemaking proceeding, and we cannot decide them here. However, the Commission does find it appropriate as a part of this rulemaking proceeding to note that the versions of Rule R6-19.2(f) in effect in the past did not specify whether the annual review of consumption was to be based on meeting the threshold for reclassification during any one month of the two-year review period, during any one month of each year of the two-year period, during any two months of the period, during any one year of the period, or during both years. Further, the Commission did not in the past approve or even suggest any specific methodology, as we do today. Given the history of the rule (which at one point provided for a two-month, rather than a two-year, review period), the Commission finds it understandable and reasonable that the LDCs arrived at different methods in the past. We do not by this conclusion speak to Public Service's changing of methods since those changes involve not only interpretation of the rule itself but also Public Service's reasons for changing methods. Public Service's situation is more appropriately dealt with in the Eaton complaint case now pending before the Commission.

Finally, the Public Staff raised two additional issues in its Reply Comments. It suggested that "each partial day of involuntary curtailment should be counted as a whole day. . . " The Commission need only note that the methodology filed by Public Service and adopted herein already accomplishes this by defining involuntary curtailment days as "those days or portions of days . . . " Second, the Public Staff suggested that "[b]illing blocks within a rate schedule should be prorated so that customers do not lose the benefit of a lower block due to involuntary curtailment." Public Service responded that this is "a billing issue which is totally irrelevant to the classification issues addressed in this docket," and the Commission agrees.

IT IS, THEREFORE, ORDERED as follows:

1. That the existing version of Rule R6-19.2(f) should be, and hereby is, amended and moved and renumbered as Rule R6-12(7) as of the date of this Order;

2. That a new section dealing with reclassification of customers' curtailment priorities should be, and hereby is, written and numbered and adopted as Rule R6-19.2(f) as of the date of this Order;

3. That Public Service, Piedmont and NCNG shall henceforth use the methodology attached to Public Service's Supplemental Comments of November 8, 1990 (within the exception noted herein for the addition or retirement of major equipment), for implementing both the new Rule R6-12(7) and the new Rule R6-19.2(f);

4. That Public Service, Piedmont and NCNG shall incorporate this methodology into their rules and regulations and shall file such revised rules and regulations with the Commission within ten days from the date of this Order;

5. That Public Service, Piedmont and NCNG shall mail notice of the new Rule R6-12(7) and the methodology to implement it to their industrial customers;

6. That the notice of reclassification required by Rule R6-12(7) shall be made by registered or certified mail, return receipt requested; and

7. That the three complaint cases previously suspended by the Commission (Long Manufacturing of N.C., Inc. v. NCNG, Docket No. G-21, Sub 284; Runnymede Mills, Inc. v. NCNG, Docket No. G-21, Sub 285; and Sapona Manufacturing Company, Inc. v. Piedmont, Docket No. G-9, Sub 301) shall proceed in their own dockets upon motion of a party consistent with the present Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

APPENDIX A

DOCKET NO. G-100, SUB 48 (Reopened)

RULE R6-12(7)

(7) During July and August of each year, consumption for each customer for the twelve-months ending June 30 of such year and the prior year shall be reviewed. If it is found that the customer has either increased or decreased his annual consumption based on the two prior years' consumption to the point it would place him on a different rate schedule, the customer shall be automatically reclassified to the proper rate schedule effective the following September 1. In determining consumption, periods of involuntary curtailment shall be excluded.

Each customer reclassified under this rule shall be notified of the change in rate schedule, along with a copy of the tariff sheets applicable to his old and new rate schedules, at least twenty-one days prior to the effective date of the change.

RULE R6-19.2(f)

(f) During July and August of each year, consumption for each customer for the twelve-months ending June 30 of such year and the prior year shall be reviewed. If it is found that the customer has either increased or decreased his annual consumption based on the two prior years' consumption to the point it would place him in a different priority classification, the customer shall be automatically reclassified to the proper priority classification effective the following September 1. In determining consumption, periods of involuntary curtailment shall be excluded.

DOCKET NO. R-100, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petitions by Railroads to Abandon Sidetracks Serving One Industrial Customer and Covered by Private Sidetrack Agreement	))))	ORDER ADOPTING RULE R3-10

BY THE COMMISSION: On November 5, 1990, the Commission received a letter on behalf of CSX Transportation, Inc. (CSX), concerning sidetrack abandonments as set forth in G.S. 62-247 which states, in pertinent part: "A railroad company which has established and maintained for a year or more a ... facility for serving the public at a point upon its road or route shall not abandon such ... facility for serving the public ... except by approval of the Commission which may be sought by the filing of an appropriate petition seeking the necessary authority."

The issue raised by CSX is whether Commission approval is required to abandon a sidetrack formerly serving only one industrial customer and covered by a private sidetrack agreement.

By Order dated March 7, 1991, the Commission initiated a proceeding to consider the adoption of proposed Commission Rule R3-10. The Order was mailed to all railroads operating in North Carolina. The Order provided that parties desiring to file comments should do so on or before April 5, 1991, and reply comments not later than April 26, 1991. The Commission would then render its decision in the matter based upon the record and comments received.

Comments were timely filed with the Commission by CSX Transportation, Inc., Norfolk and Western Railway Company, Norfolk Southern Railway Company, Aberdeen and Rockfish Railroad Company, and Alexander Railroad Company. These railroads support the adoption of proposed Rule R3-10 with the change that the railroad is not required to notify the Commission of such abandonment in writing.

Upon consideration of the comments and the entire record in this docket, the Commission is of the opinion, finds and concludes, that the proposed Rule R3-10 with the requested change by the railroads should be adopted.

IT IS, THEREFORE, ORDERED:

1. That Commission Rule R3-10 is hereby amended as set forth in Appendix A attached hereto to become effective as of the date of this Order.

2. That copy of this Order shall be mailed by the Chief Clerk to all railroads operating in North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

Rule R3-10. Abandonment of Station or Other Facilities or Diminution of Accommodations.

A railroad company which has established and maintained for one year or more a passenger station, freight depot, team track, or other facility for serving the public at a point upon its road or route shall not abandon such station, depot or team track or other facility for serving the public nor substantially diminish the accommodations at said station, depot or team track by the stopping of trains or otherwise except by approval of the Commission which may be sought by the filing of an appropriate petition seeking the necessary authority; provided, however, that where a sidetrack serving only one industrial customer is to be abandoned in compliance with the terms of a private contract between the railroad company and the respective industrial customer, no application need be filed. Freight or passenger depots may be relocated upon the written approval of the Commission.

DOCKET NO. P-100, SUB 65

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Investigation to Consider the Implementation of a Plan for Intrastate Access Charges for All Telephone Companies Under the Jurisdiction of the North Carolina Utilities Commission	))))	ORDER REGARDING PHONE AMERICA PETITION

BY THE COMMISSION: On November 14, 1990, Phone America of Carolina, Inc. (Phone America), filed a petition seeking a modification of the Commission's policies in the access services tariff (AST) requiring the placement of both the clearinghouse agent's name and the carrier's name on intrastate billing statements to end-users (the "dual-name requirement"). Specifically, Phone America noted paragraph 6 in Appendix A of the February 7, 1989, Order by the Commission. This provision stated:

> The name of the IXC on whose behalf the clearinghouse agent is receiving intrastate billing and collection services must be stated on the bill. The name of the clearinghouse agent should also appear on the bill.

Other AST provisions permit the clearinghouse agent to bill and collect only on behalf of a certificated entity. Just as importantly, only those LECs whose billing systems are capable of complying with the above AST requirements were permitted to provide intrastate billing and collection services to clearinghouse agents.[1]

Phone America stated that it had concluded, or was in the process of concluding, individual billing and collection agreements with various LECs but that to conclude individual billing and collection agreements with every LEC was cost prohibitive. Furthermore, Phone America stated that it cannot utilize clearinghouse agents because of the inability of many LECs to put the carrier's name along with that of the clearinghouse on the customer bill as required by the current AST. Phone America alleged that it was losing between $20,000 and $30,000 per month which it could not bill due to this dilemma.

Phone America requested the Commission put its petition out for comment and requested that the Commission consider whether to require LECs to modify their billing packages to comply with the dual-name requirement or, alternatively, order the LECs to bill and collect bills provided by clearinghouse agents who provide proof to the LECs that the only intrastate messages which will be sent for collection are from certificated carriers (presumably without the necessity of the underlying carrier's name appearing on the bill).

On November 28, 1990, the Commission issued an Order requesting comments regarding the Phone America petition. The following companies filed comments: ALLTEL (on behalf of ALLTEL Carolina, Inc., Heins Telephone Company, and Sandhill Telephone Company), Carolina Telephone and Telegraph Company (Carolina), Central Telephone Company (Central), Concord Telephone Company (Concord), GTE South (GTE), Lexington Telephone Company (Lexington), and North State Telephone Company (North State). Also filing comments were Carolina Telephone Long Distance, Inc.

(CTLD), the North Carolina Pay Phone Association, Inc. (NCPA), and joint comments by Integretel, Inc., and Operator Assistance Network (collectively Integretel). The Commission posed four questions to the companies as follow:

a. Whether LECs should be required to modify their billing packages so that both the clearinghouse agent and the underlying carrier name should appear on the file. LECs should provide data on whether they have this capacity and when they believe they can obtain it.

b. Whether LECs should be authorized to bill and collect bills provided by clearinghouse agents without the necessity of the underlying carrier's name appearing on the bill.

c. If (b) is recommended, what safeguards should be enacted to assure that only the bills of certificated entities are submitted and what measures of comparable effectiveness to present policy should be enacted to protect the interest of end-users in being able to identify and contact their underlying carrier? Parties should address these issues with respect to both IXCs and COCOTs.

d. What is the cost to the LECs of modifying billing and collection programs to identify both the clearinghouse agent and the underlying carrier:

   (1) For those LECs that currently provide for this service, the actual cost incurred for the modification and how that cost was derived?

   (2) For those LECs that do not currently provide this service, the projected cost of such modification and how this projected cost is derived?

A summary of their comments follows:

1. With regard to the first question, most comments indicated that the Commission should not require the LECs to modify their billing system to include the names of both the clearinghouse agent and the underlying carrier on the bill. Only Lexington and NCPA believe that the underlying carrier's name should be included on the bill. While Lexington indicated that only the underlying carrier should be listed, NCPA believed that names should be printed on the bill.

2. The second question also elicited near uniformity in the comments. Virtually all commenters stated that the LECs should be permitted to bill for clearinghouse agents without the necessity of including the name of the underlying carrier on the bill. Only Lexington believed that the underlying carrier should be listed on the bill.

3. The third question concerned safeguards to be enacted should the Commission decide to permit LECs to include only the clearinghouse agent name on the bill. This question illicited various responses. However, the basic safeguard suggested was some type of documentation by clearinghouse agents that the intrastate calls submitted to the LECs are from only certified interexchange carriers (IXCs) or COCOT providers authorized to provide automated collect calls.

Central suggested periodic checks to ensure that the clearinghouse agents were submitting intrastate billing on behalf of certified IXCs or authorized COCOT providers but did not indicate how the checks were to be made or who would be responsible for such checks other than to indicate that the LECs should not be responsible.

4. The last question regarding the cost of modifying billing systems produced widely varying answers from the LECs. ALLTEL estimated the cost to be $1,078,000, while Concord and Lexington each estimated the cost to be $1,000. Carolina estimated its cost to be $230,000 and GTE stated its North Carolina cost was $22,300. North State estimated a cost of $8,000 while Central considers its system modification cost to be proprietary and did not submit an estimate.

Public Staff comments

The Public Staff submitted its comments on February 1, 1991, and stated that it still has misgivings about deleting the dual-name requirement but because of the apparent technical and economic problems faced by the LECs with the implementation of this requirement, the Public Staff stated that it would "acquiesce" at this time in the elimination of the requirement. The Public Staff stated that it would seek reinstatement of the requirement in the future if the nature and level of subscriber complaints indicate that such an action was needed. The Public Staff warned that the elimination of the dual name requirement would increase the possibility that uncertified IXCs could utilize the billing contracts clearinghouse agents have with the LECs to bill for intrastate calls. The Public Staff therefore recommended that, if any uncertified IXC is found to be billing for intrastate calls through clearinghouse agents, the Commission should seek available legal remedies including monetary penalties pursuant to G.S. 62-310. The Public Staff stated that its recommendations in this proceeding are predicated upon the Commission taking action including monetary penalties against violators.

The Public Staff also noted that the elimination of the dual-name requirement would increase the possibility that clearinghouse agents will be responding to customer inquiries and complaints regarding calls completed by IXCs and COCOT providers. The Public Staff noted that regardless of who bills for the calls, the certified IXC has the ultimate responsibility for compliance with its tariffs and the Commission's rules. Therefore, the Commission should make clear that IXCs must take whatever measures are necessary to ensure that their clearinghouse agents handle customer complaints and inquiries in a manner consistent with their tariffs and Commission rules.

The Public Staff also noted apparent discrepancies between certain LEC tariffs and the capabilities of the LECs to provide customer bills with the names of both the clearinghouse agents and the underlying carrier. The Public Staff noted that tariffs on file with the Commission indicate that the following LECs have the capability of providing billing service to clearinghouse agents in accordance with the current provisions: Citizens, Concord, Ellerbe, GTE, Lexington, Mebane Home, North State, Randolph, and Southern Bell. However, Concord, Lexington, and North State stated that they did not have the capability to provide clearinghouse agent billing. Therefore, the tariffs of some LECs appear to be misinforming the Commission and Public Staff of their service capabilities in filing inaccurate tariffs. Furthermore, in response to a billing inquiry from the Public Staff in September 1990, Concord indicated that it had the capability to provide billing services to clearinghouse agents.

Attorney General comments

The Attorney General filed comments on February 1, 1991. The Attorney General supported the dual-name requirement and recommended that it be made mandatory within the next two years. The Attorney General also noted various conflicts in comments. For example, Phone America suggested that it could not get subcarrier identification codes (sub-CICs) and could therefore not get its name printed on LEC bills while North State said sub-CICs were not provided in its message record by its service bureau so that it could not print the carrier's name on the bill. However, GTE South and Lexington stated that they could print the carrier's name on the bill.

The Attorney General also proposed that interim regulations be promulgated pending mandatory implementation of the dual-name requirement to afford relief to certified IXCs like Phone America while at the same time providing telephone users sufficient information to pursue inquiries about questionable bills. The Attorney General suggested that on an interim basis the Commission allow LECs to bill for certified entities or clearinghouses if LECs stated on the bill that the clearinghouse is a billing agent for a telephone carrier certified to do business in North Carolina. The bill must also state that billing inquiries can be made to the LEC or the clearinghouse, and it must include toll-free numbers for those companies. Finally, the bill must state that either the LEC or the clearinghouse will direct the users to a toll-free number for the underlying carrier, if necessary. In addition to these safeguards, the Commission should order the LECs to obtain verification from clearinghouses that its customers are certificated in North Carolina. Without that verification, the LECs could not bill for the clearinghouse or service bureau. The cost of all of these measures should be billed to the clearinghouse or to the carrier.

The Attorney General also noted that OAN on behalf of COCOT providers suggested that Southern Bell's COCOT tariff did not comply with the Commission's orders in this docket or Docket No. P-100, Sub 84. In view of OAN's assertions, the Attorney General suggested that the Commission order Southern Bell to reply to OAN's assertion in Docket No. P-100, Sub 84.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission believes that the retention of the dual-name requirement is in the public interest since it enables the end-user to have knowledge and notice of who is involved in the carriage and billing of his calls. At the same time, the Commission is sensitive to the burden placed on firms such as Phone America which are unable to have calls billed in the territories of LECs that cannot yet satisfy the dual-name requirement. The Commission notes that more and more LECs are modifying their billing and collection systems, enabling them to satisfy the dual-name requirement. This is a trend which the Commission applauds.

Nevertheless, the Commission believes LECs should be required to modify their billing and collection systems to satisfy the dual-name requirement within a two-year time period. The Commission believes that this is sufficient time for LECs that cannot comply with the dual-name requirement to do so and will not be unduly expensive.

However, the Commission also believes it is equitable to provide interim relief to firms such as Phone America. Therefore, on an interim basis, those LECs that do not comply with the dual-name requirement shall print only the name of the clearinghouse agent on the customer bills, subject to certain requirements set out below. Within two years, all LECs are to comply with the dual-name requirement.

IT IS, THEREFORE, ORDERED as follows:

1. That the LECs be required to comply with the dual-name requirement within two years of the issuance of this Order.

2. That, on an interim basis, those LECs that do not comply at the present time with the dual-name requirement shall print the name of the clearinghouse agent on customer bills subject to the following conditions:

a. The LECs must state on the bill that the clearinghouse agent is a billing agent for telephone carriers certified to do business in North Carolina.

b.. The LEC must state on the bill that billing inquiries can be made to the LEC or the clearinghouse agent and include toll-free numbers for these companies.

c. The LECs must state on the bills that the LEC or clearinghouse agent will direct users to a toll-free number for the underlying carrier on request.

d. The LEC must obtain verification from the clearinghouse agent that the entities on whose behalf it is billing are certificated in North Carolina. Otherwise, the LEC cannot bill for the clearinghouse agent.

3. That all LECs file or cause to be filed revisions to all applicable ASTs reflecting the requirements of Ordering Paragraphs Nos. 1 and 2 above no later than Wednesday, May 1, 1991, to be effective on Wednesday, May 15, 1991.

4. That Concord, Lexington, and North State be required to modify their tariffs to reflect their actual capabilities to satisfy the dual-name requirement.

5. That Southern Bell be required to respond within four (4) weeks of the issuance of this Order to OAN's assertion that it is not complying with the

Commission's Order in Docket No. P-100, Sub 84, in that Southern Bell has adopted a tariff provision prohibiting COCOTs from using either Southern Bell or clearinghouse agents for billing inquiry services.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of March 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

DOCKET NO. P-100, SUB 84

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	
Issuance of Special Certificate for Provision of Telephone Service by Means of Customer-owned Pay Telephones	ORDER INITIATING RULEMAKING TO REVISE RULE R13-6(d) TO ALLOW NUMBERS ACCESS RESTRICTIONS IN CONFINEMENT FACILITIES

BY THE COMMISSION: On August 16, 1991, Southern Bell Telephone and Telegraph Company (Southern Bell) filed a Motion to Amend Rule R13-6(d) to allow the administrator of a confinement facility to restrict access by COCOTs in confinement facilities to certain telephone numbers. Although not a COCOT, Southern Bell would have an interest in a tariff revision comparable to a rule change for COCOT providers. The specific amendment that Southern Bell is proposing is set out below and is underlined in the text:

> Rule R13-6. Special Rules for Service Within Confinement Facilities. Notwithstanding any other rules in this Chapter, PTAS instruments located in the detention areas of local, state, or federal confinement facilities:
>
> . . . d) shall be arranged or programmed to allow only 0+ collect calls for local, intraLATA toll, and interLATA toll calls and to block all other calls including, but not limited to, local direct calls, credit card calls, third number calls, 1+ sent paid calls, 0+ sent paid calls, 0- sent paid calls, 800 calls, 900 calls, 976 calls, 950 calls, 911 calls, and 10XXX calls. If specifically requested by the administration of the confinement facility, restriction of access to specifically identified numbers may be permitted. Provided, however, if specifically requested by the administration of the confinement facility, 1+ toll and seven-digit local dialing may be permitted if the local exchange company or the telephone instrument can block additional digit dialing after an initial call setup.

Southern Bell argued that such an amendment would allow the administrator to block access to certain numbers such as those of judges, jurors, and witnesses. Southern Bell stated that administrators support such a rule and that a rule revision is appropriate to deter fraud and abuse in the inmate setting.

The Commission believes that interested parties should be invited to comment on the specific issue of whether the administration of a confinement facility should be allowed to restrict access to specifically identified numbers, and, if so, to what extent. Those who comment should refer to the language proposed by Southern Bell and propose alternative language to reflect their own views, if different.

IT IS, THEREFORE, ORDERED as follows:

1. That a rulemaking proceeding be, and the same is hereby, initiated to consider a revision to Rule R13-6(d) to allow numbers access restrictions in confinement facilities as proposed by Southern Bell in its August 16, 1991, motion.

2. That any party having an interest in this proceeding file comments and any other relevant information no later than Friday, October 11, 1991. Reply comments are due no later than Friday, November 1, 1991.

3. That a copy of this Order be mailed by the Chief Clerk to the following persons or entities: All parties to Docket No. P-100, Sub 84; the North Carolina Payphone Association; the North Carolina Sheriffs' Association; the North Carolina League of Municipalities; the North Carolina Association of County Commissioners; the United States Attorneys of the Eastern, Middle, and Western Districts of North Carolina; the North Carolina Department of Corrections; the North Carolina Department of Corrections Inmate Grievance Committee; the North Carolina Chapter of the American Civil Liberties Union; and North Carolina Legal Services.

4. That any person desiring to intervene in this matter as a formal party file a motion pursuant to NCUC Rules R1-6, R1-7, and R1-19.

ISSUED BY ORDER OF THE COMMISSION.
This the 20th day of August 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Gail Lambert Mount, Deputy Clerk

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Establishment of a Dual-Party Relay System	ORDER SETTING SURCHARGE AND PROCEDURES FOR IMPLEMENTATION OF SYSTEM

BY THE COMMISSION: On July 7, 1989, the North Carolina General Assembly passed HB 1186 (Chapter 599), codified as G.S. 62-157, in order to establish a dual-party relay system to enable the hearing or speech impaired to have better access to the telephone network.

The concept behind dual party relay is relatively simple. A hearing or speech-impaired person with a special telecommunications device known as a TDD would be able to communicate with a hearing person because the relay center operator would pass on the message orally. Conversely, a hearing person would be able to communicate with the hearing or speech impaired person because the relay center operator would pass on the message via TDD. G.S. 62-157(f) specifies that users of the relay service are to be charged approved long-distance and local rates (including the surcharge), but no additional charges are to be imposed for the use of the relay system.

The legislation gave to the North Carolina Department of Human Resources (DHR) overall responsibility for administering the system, "including its establishment, operation and promotion," and provided that DHR may contract out the provision of service for four-year periods to one or more service providers.

The North Carolina Utilities Commission was charged with designating the appropriate monthly surcharge, not to exceed $0.25, and developing procedures with the State Treasurer for the deposit and disbursement of monies collected. The Commission was also asked to consult with DHR concerning a format and filing schedule for a comprehensive financial and operational report to be prepared by DHR and submitted to the Commission and the Joint Legislative Utility Review Committee. The General Assembly also conferred on the Commission "the same power to regulate the operation of the dual party relay system as it has to regulate any public utility subject to the provisions of this chapter." (G.S. 62-157(h).

On January 30, 1990, DHR filed an initiating petition in compliance with G.S. 62-157(c), and subsequently requested and received proposals from interested companies for the actual provision of the service. On September 28, 1990, DHR filed a "Review and Evaluation of the Proposals for the Dual Relay Telephone System for North Carolina," which favored Sprint Services as the contractee to provide the services.

On October 5, 1990, the Commission issued an Order Giving Notice and Requesting Comments. The Order requested detailed additional information from DHR and requested each local exchange company (LEC) and telephone membership corporation (TMC) to file comments on appropriate compensation, a projection of total access lines (excluding those of Subscriber Line Charge Waiver and Link-Up Carolina participants), and the estimated length of time required to implement the billing of surcharge and long-distance charges. The Order also requested recommendations from the State Treasurer.

All the LECs and TMCs responded with the information requested. DHR filed information on November 5, 1990, as well as a supplemental filing on January 4, 1991. The State Treasurer made filings on November 2, 1990, and December 27, 1990. The Public Staff filed comments and recommendations on December 6, 1990, and January 18, 1991.

After careful consideration of all the filings in this docket, the Commission reaches the following

CONCLUSIONS

1. The appropriate surcharge should be 11¢ per qualified access line including a 1¢ compensation level for LECs and TMCs. The Commission is adopting these figures pursuant to the recommendation of the Public Staff. The base surcharge level was determined by dividing DHR's initial year's cost by the

number of qualified access lines and dividing this number by 12 months. Qualified access lines mean the total access lines minus the access lines of customers on the Subscriber Line Waiver or Link-Up Carolina programs.

Added to the base surcharge level is an amount to compensate the LECs and TMCs for surcharge "collection, inquiry, and other administrative services" pursuant to G.S. 62-157(f). Many of the TMCs and LECs stated that 1% of collected monthly surcharge revenues was inadequate. Carolina Telephone went on to provide an analysis suggesting another compensation level. The Public Staff in its January 13, 1991, filing suggested a compensation level of 1¢ per qualified access line. Figuring in the appropriate compensation level, the initial monthly surcharge should be 11¢.

In order to derive a more accurate view of appropriate compensation levels for the future, Southern Bell and Carolina Telephone should be required to file cost studies supporting an appropriate level of compensation within six months of actual implementation of the system.

2. The LECs and TMCs should be required to insert a separate line item on telephone bills to customers to show the surcharge. This is required by G.S. 62-157(c) which states in relevant part that the "surcharge shall be identified on customer bills as a special surcharge for provision of a dual party relay system."

3. The LECs and TMCs should be required to notify customers of the Dual Party Relay System by bill insert in the next billing cycle after the issuance of this Order. The content of this bill insert is set out in Appendix A.

4. The collection and disbursement of funds should be done on the following basis:

a. Monthly surcharge

1. The LECs and TMCs will collect the surcharge from their qualified customers.

2. The LECs and TMCs will transmit the collected surcharge revenues minus 1¢ per qualified access line for surcharge billing and collection services to DHR on a monthly basis. The first remittance should be made by May 5, 1991. The checks issued by the LECs and TMCs should be issued payable to "DHR-Relay North Carolina."

3. DHR will deposit the surcharge revenues collected with the State Treasurer's Office or his designee on a daily basis with a prepared certification of deposit form accompanying the deposit identifying the separate budget code as assigned by the Office of State Budget and Management.

4. The State Treasurer will maintain the funds in an interest-bearing, nonreverting account for use by DHR for the dual party relay system.

b. Long distance relay calls

1. The LECs and TMCs will collect from end-users the long-distance relay call charges as part of the LEC or TMC monthly telephone bill.

2. The LECs and TMCs will forward these receivables to US Sprint.

3. US Sprint will transmit these funds to Sprint Services, which will in turn forward the revenues to DHR.

4. DHR will deposit the revenues with the State Treasurer as described above.

The Commission believes that the procedures specified above are a workable solution to a complex problem. With respect to deposit of funds, the Commission has elected to follow the recommendations in the State Treasurer's filing of December 27, 1990.

5. The full in-service implementation date of the service should be June 1, 1991. The Public Staff and DHR have recommended that, in order to comply with the "reasonable margin for reserve" requirement in G.S. 62-157(c) and in order to establish an initial positive balance, the collection of the surcharge should begin two months prior to the implementation of the service. It is also necessary to allow adequate time for customer notification, modification of computer systems, and exchange of information among participating entities. The Commission therefore believes that the service should go into actual operation on June 1, 1991, and that the LECs and TMCs should be authorized to collect the surcharge beginning April 1, 1991.

6. There is to be a correlation between US Sprint's tariffs and those of DHR with respect to the dual party relay system. DHR has stated that it will charge US Sprint tariffed intrastate rates applicable to speech and hearing impaired users. Discount rates for North Carolina TDD users' interstate calls will be 35% off day rates, 25% off evening rates and 10% off night/weekend rates. The interstate discount rate is subject to approval by the Federal Communications Commission, and Sprint Services will not be compensated for such calls through this intrastate relay system. Since the US Sprint tariffs are already on file with the Commission, the Commission will consider the applicable tariffs with respect to DHR to be on file by reference. Approved changes in the US Sprint tariff will automatically change the applicable DHR tariff.

7. DHR should be required to file a comprehensive financial and operational report as set out below. Sprint Services and the LECs and TMCs should be required to file reports with DHR as set out below. G.S. 62-157(g) provides that the Commission was to consult with DHR to develop a format and filing schedule for a comprehensive financial and operational report on the dual party relay system, to be prepared by DHR and filed with the Commission and the Joint Legislative Utility Review Committee. Pursuant to recommendations from the Public Staff and from DHR, the Commission believes that:

a. DHR should be required to file a comprehensive financial and operational report every six months with the Commission, the Public Staff, and the Joint Legislative Utility Review Committee in the format as set out in Appendix B.

b. Sprint Services should be required to file monthly reports with DHR and a compilation report with DHR every six months in the format as set out in Appendix B so that DHR may prepare the above report.

c. The LECs and TMCs should be required to file a monthly report with DHR showing the level of surcharge revenues collected during the reporting period, number of qualified access lines for which the surcharge was collected during the reporting period, the billing and collection charges associated with the collection of the surcharge and withheld by the company during the reporting period, and the revenues mailed to DHR (collected revenues minus charges withheld) during the reporting period. The reports should be filed concurrent with the deposit made to the special fund. This information should be included by DHR in its comprehensive financial and operating report.

8. LECs and TMCs should be required to file local calling scope information within 30 days from the issuance of the Order, to be updated as changes occur. In order for calls to be properly rated, the Commission believes that the LECs and TMCs should be required to provide local calling scope information to Sprint Services in the format set out in Appendix C. Sprint Services has indicated that it will provide the format directly to all LECs and TMCs. These forms should be returned directly to Sprint Services within 30 days of the issuance of this Order. This information should be updated by the LECs and TMCs as changes occur.

9. All parties to this docket should be reminded to send copies of all their future filings in this docket to all other parties to this docket. A list of the parties to this docket is set out in Appendix D. Updated lists of LECs and TMCs can be obtained from time to time from the Commission Chief Clerk's Office.

IT IS, THEREFORE, ORDERED as follows:

1. That the surcharge level for the dual party relay system be set at 11¢ per qualified access line per month and that all LECs and TMCs be authorized to withhold as compensation for collection, inquiry, and other administrative services associated with the surcharge, the sum of 1¢ per qualified access line per month.

2. That Southern Bell and Carolina Telephone file cost studies supporting an appropriate level of compensation for billing and collection of the surcharge by no later than December 1, 1991.

3. That the in-service implementation date of the dual party relay system be set for June 1, 1991.

4. That all LECs and TMCs do the following:

a. Begin collecting the surcharge authorized in Ordering Paragraph No. 1 above on April 1, 1991.

b. Insert a separate line item on all customer telephone bills to identify the surcharge as follows: Special Surcharge for Dual Party Relay System.

c. Notify all customers of the system by way of bill insert, as set out in Appendix A.

d. File monthly reports concurrent with deposits for the special fund with DHR showing the following:

(1) level of surcharge revenues collected during the reporting period,

(2) number of qualified access lines for which the surcharge was collected during the reporting period,

(3) the billing and collection charges associated with the collection of the surcharge and withheld by the company during the reporting period, and

(4) the revenues mailed or delivered to DHR (i.e., collected revenues minus charges withheld) during the reporting period.

e. Follow the procedure for the collection and disbursement of funds as outlined in Conclusion No. 4.

f. File local calling scope information with Sprint Services within 30 days of this Order in the format set out in Appendix C, to be updated as changes occur.

5. That Sprint Services do the following:

a. Follow the procedures for the collection and disbursement of long-distance relay funds as set out in Conclusion No. 4.

b. File monthly reports with DHR and a compilation report with DHR every six months in the format set out in Appendix B.

6. That DHR do the following:

a. Follow the procedure for the collection and disbursement of funds as set out in Conclusion No. 4.

b. File a comprehensive financial and operational report every six months with the Commission, the Public Staff, and the Joint Legislative Utility Review Committee in the format set out in

Appendix B. The first such report covering the first six months of operation is due seven months from the initiation of the service, and all subsequent six-month reports are due every six months thereafter.

7. That the State Treasurer follow the procedure for the collection and disbursement of funds as set out in Conclusion No. 4.

8. That all parties be reminded to send copies of all their future filings in this docket to all other parties to this docket and that the monthly surcharge and long-distance relay revenues are not subject to gross receipts tax or sales tax per G.S. 62-157(b).

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

For Appendix B See Official Copy of Order in Chief Clerk's Office.

APPENDIX A

NOTICE
NORTH CAROLINA DUAL-PARTY RELAY SYSTEM

In June, the State of North Carolina will launch a new service, Relay North Carolina, which will make it easier for North Carolinians who are deaf, hard of hearing, or speech-impaired to communicate over the telephone network to voice users.

Created through the efforts of the North Carolina General Assembly, the North Carolina Department of Human Resources, the North Carolina Utilities Commission, and the Public Staff - North Carolina Utilities Commission, the Relay North Carolina Service will be provided by specially trained communications assistants. Using special telecommunications equipment, these operators relay conversations between North Carolinians with hearing and/or speech impairments and callers who use standard telephone equipment.

Relay North Carolina allows persons who are deaf, hard of hearing, or speech-impaired to utilize a Telecommunications Device for the Deaf (TDD) or personal computer equipped with a modem to call the relay center and communicate over the telephone lines with voice users. A relay agent acts as an interpreter between the typed conversation from the TDD user and the voice communications of the hearing user.

Calls also can be initiated by voice users who wish to speak with a TDD user who is deaf, hard of hearing, or speech-impaired.

The service will be provided 24 hours a day, seven days a week and will facilitate communications for both local and long-distance calls. There will be no charge to users for local calls. Long-distance calls placed to destinations within the State of North Carolina will be discounted 50 percent, and long-distance calls to or from destinations outside of North Carolina will be discounted an average of 23 percent, based on the time of day the call was placed. Long-distance service for the relay center will be provided by US Sprint.

Funding for the relay service will be provided through a monthly surcharge of 11 cents which will appear on all telephone company customer bills beginning in April 1991.

Beginning June 1, 1991, callers can access the Relay North Carolina Center by calling toll-free: 1-800-RELAY-NC (1-800-735-2962).

For more information, write to Relay North Carolina, c/o Division of Services for the Deaf and the Hard of Hearing, Department of Human Resources, 695-A Palmer Drive, Raleigh, North Carolina 27603, or telephone (919) 733-5199 Voice/TDD.

TELECOMMUNICATIONS FOR THE DEAF

The General Assembly has appropriated funds to the Division of Services for the Deaf and the Hard of Hearing, North Carolina Department of Human Resources, for the implementation of a communications program for low-income individuals who have been certified as deaf, hearing impaired, speech impaired, or deaf-blind in accordance with General Statutes 143B-216.34B. This program provides TDDs and other telephone assistive listening devices on loan to eligible applicants over nine years of age who are permanent legal residents of the State of North Carolina. Should you be interested in additional information or in applying for loaner equipment through this program, please contact the Division of Services for the Deaf and the Hard of Hearing, Department of Human Resources, 695-A Palmer Drive, Raleigh, North Carolina 27603, or telephone (919) 733-5199 Voice/TDD.

DOCKET NO. P-100, SUB 110

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Establishment of Dual Party Relay System	ORDER CONCERNING LINE ITEM ON BILL

BY THE COMMISSION: On February 5, 1991, the Commission issued an Order Setting Surcharge and Procedures for Implementation of System in this docket. In Ordering Paragraph 4(b), the Commission directed local exchange companies (LECs) to insert a separate line item on all customer telephone bills to read, "Special Surcharge for Dual Party Relay Systems." The intent of that provision was to comply with G.S. 62-157(c) to enable customers to fully and accurately identify the new charge.

It has come to the Commission's attention that some LEC billing systems are unable to accommodate a line item of this character length. Therefore, as to those LECs on TMCs whose billing systems cannot reasonably accommodate the line item as originally designated, the Commission believes those LECs or TMCs should be allowed to use the phrase: Surcharge for Relay N.C. LECs or TMCs whose billing systems can reasonably accommodate the line item as originally written should use the original line item.

IT IS, THEREFORE, ORDERED that Ordering Paragraph 4(b) of the February 5, 1991, Order in this docket be amended by adding the sentence: "Those LECs or TMCs whose billing systems cannot reasonably accommodate the foregoing line item may utilize the phrase: Surcharge for Relay N.C."

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of March 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. P-100, Sub 111
DOCKET NO. P-140, Sub 28

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of An Investigation of Billing and Collection Services for 700, 900 and 976 Services and Tariff Filing by AT&T Communications of the Southern States, Inc., to Offer MultiQuest Service	)	ORDER ALLOWING MULTIQUEST TARIFF, INTRASTATE 900 SERVICE, AND REQUESTING COMMENTS FOR FINAL RULES

BY THE COMMISSION: In letter dated August 10, 1990, AT&T of the Southern States, Inc. (AT&T) filed tariffs to offer MultiQuest Service in Docket No. P-140, Sub 28. On August 29, 1990, Public Staff filed a Petition to Suspend Tariffs and to Institute Investigation in the matter of AT&T's proposed MultiQuest tariff.

On September 5, 1990, the Attorney General filed a Motion to Suspend and Consolidate and Continue and argued that the issues of the MultiQuest tariff were so bound up with pending Docket No. P-100, Sub 111, that the tariff should either be suspended pending disposition of that docket or consolidated with it.

In its September 20, 1990, Order Suspending Tariff in P-140, Sub 28, the Commission found that AT&T's MultiQuest tariff filing should be suspended pending outcome of the proceeding in Docket No. P-100, Sub 111, and further Order.

Docket No. P-100, Sub 111, is an investigation into the billing and collection practices that local exchange companies (LECs) perform for sponsors of 900-type services. This docket was opened in response to Petition filed by Public Staff and a Motion filed by Attorney General, both filed on August 22, 1990.

In its Petition filed August filed August 22, 1990, Public Staff stated its Petition was prompted principally by the increasing number of complaints received concerning interstate 900 services. The Public Staff further stated the complaints were such that it believed Commission action was urgently needed.

The Public Staff therefore petitioned the Commission:

1) to institute a docket to investigate billing, collection, credit implications, and blocking of 700, 900, and 976 services, and;

2) to issue immediately an interlocutory order prohibiting a LEC from disconnecting local service and an IXC from suspending intrastate long distance service for failure to pay for 700 or 900 calls.

The Attorney General in his Motion indicated that an investigation was appropriate and moved that the Commission institute an investigation for the purpose of clarifying the authority of LECs under its jurisdiction to bill and collect for 900 programs and that, at a minimum, said investigation address those issues raised by this motion.

On September 4, 1990, this matter came before the Regular Commission Conference. On September 7, 1990, the Commission issued an Order Forbidding Cutoff and Authorizing Blocking for Nonpayment of 900 and 900-like charges.

This Order, besides forbidding cut-off of local service for nonpayment of 900 service, required the LECs to follow certain procedures with respect to outstanding 900 service charges:

1. If the subscriber is willing to make payment the LEC shall attempt to make reasonable arrangements for payment.

2. If the subscriber challenges the bill or is otherwise unwilling or unable to pay, the LEC shall write off the charges on the first such occasion. The subscriber shall be offered free blocking.

3. If the subscriber, on the second occasion, incurs charges which he challenges or is otherwise unwilling or unable to pay, the LEC shall be authorized to block the 900 service of such subscriber at no charge to the subscriber.

The Commission also issued an Order Initiating Investigation on September 7, 1990.. This latter Order listed 14 issues related to Investigation of Billing and Collection Services for 700, 900 and 976 Services and ordered the LECs and IXCs, and other interested parties to file comments and recommendations in response. Initial Comments were due October 5, 1990, and Reply Comments were due October 26, 1990.

The following parties filed comments pursuant to the Commission September 7, 1990, Order Initiating Investigation:

Local Exchange Companies (LECs). Southern Bell Telephone and Telegraph Company (Southern Bell), Carolina Telephone and Telegraph Company (Carolina), Central Telephone Company (Central), Citizens Telephone Company (Citizens), Concord Telephone Company (Concord), Ellerbe Telephone Company (Ellerbe), GTE South (GTE), Lexington Telephone Company (Lexington), Mebane Home Telephone Company (Mebane), North State Telephone Company (North State), Pineville Telephone Company (Pineville), and Randolph Telephone Company (Randolph).

Interexchange Carriers (IXCs). AT&T Communications of the Southern States, Inc. (AT&T), MCI Telecommunications Corporation (MCI), and US Sprint Communications Company Limited Partnership (US Sprint).

Other Parties. Attorney General and Public Staff

Reply Comments were received from Public Staff, Attorney General, Carolina, AT&T, MCI, US Sprint and Telesphere. (The Commission has elected to consider the comments of Telesphere).

On June 7, 1991, the Attorney General filed Proposed Rules Governing Regulated Telephone Companies' Billing and Collecting for 900 Service.

Summary of Comments

The following is a summary regarding the 14 issues set out in the Commission Investigation Order of September 7, 1990.

1. Should the LECs be permitted to perform billing and collection services for providers of products and services offered through 900 services and 700 numbers used in a 900-like manner?

The Public Staff stated that, historically, the subject matter for billing and collection purposes was narrow. For example, the Access Services Tariff (AST) at its inception stated that the LECs were not to bill for telegrams, flowers, wine, or other similar services.

The Public Staff noted that a set of rules already exists for the billing of intrastate nontelecommunications services. These are the current guidelines set by Southern Bell for the provision and billing of intrastate 976 service. Public Staff believes these should serve as the minimum criteria for permitting billing and collection services for 900 services.

In addition, if the Commission authorizes intrastate 900-type services and LEC billing and collection for those services, it should be clearly stated that only 700 and 900 programs provided on behalf of customers of certified IXCs may be billed, and that before any billing services are provided, the LECs should first file and obtain approval of tariff revisions that spell out the conditions under which billing and collection services may be obtained by IXC on behalf of their 700 and 900 providers.

Public Staff recommended that the Commission adopt the billing and disconnect procedure for interstate 900 or 900-like service as indicated in Public Staff's Initial Comments in response to Questions 4 through 14.

Public Staff further pointed out in its Reply Comments that in respect to interstate 900 or 900-like calls, the Commission is essentially limited to determining whether or not the LECs can disconnect local service for nonpayment of 900 or 900-like charges. Thus, the Commission's policies regarding the local service disconnect practices of the LECs are the principal means of offering some protection to the end user regarding billing for interstate 900 or 900-like service.

The Attorney General strongly advocated a stringent set of guidelines to protect the public. The Attorney General suggested the Commission require LECs to submit tariffs which cover: Denial of Local Service and Notice; 900 Programs that Violate State Law; Limitation on Flat Rate or Per Minute Charges, and Blocking. The Attorney General also disagreed with AT&T's position that the Commission's jurisdiction over an LEC's billing and collection activities is limited to its intrastate activities and that any action taken in this docket must, of necessity, be similarly limited.

All the LECs and IXCs believed that the LECs should be permitted to perform billing and collection services for providers of products and services offered through 900 programs. LEC concern centered primarily on fear of losing the entire billing and collection revenues if the IXC or Information Provider (IP) chooses an alternative billing system. In addition, there was some concern expressed by the LECs being unable to differentiate between billing for communications services which should be permitted, and billing for products or other services provided as the result of making 900 calls, through 900 services and 700 numbers used in a 900-like manner.

2. Should the LECs be permitted to serve as billing and collection agents for 700 and 900 services that are fraudulent, unfair, deceptive, or advertised, promoted or marketed in violation of North Carolina law.

All parties agreed that the LECs should not be permitted to serve as billing and collection agents for 700 and 900 services that are fraudulent, unfair, deceptive, or advertised, promoted or marketed in violation of North Carolina law.

The LECs were resistant to making the LEC responsible for determination that the program content violates North Carolina law. The LEC has no contractual relationship with the IP, as the 900 service is established by the IP through an IXC for which the LEC provides 900 access service, and, in some cases, billing and collection services. The IXCs agreed that the LECs should not have to be responsible for policing program content, and most indicated that IXC tariffs or standards for this service in general had provisions for excluding dissemination of any matter which is in violation of North Carolina law.

3. Should the amount of 700 and 900 service charges which may appear on the bill of a subscriber be limited to a maximum per minute per call rate or a maximum flat rate per call? In the alternative, should the LECs be prohibited from serving as collection agents for any 700 or 900 program which is not preceded by a price disclosure message (flat rate maximum or per minute per call rate with maximum length of call, whichever is applicable) and which does not provide an opportunity for callers to hang up after the conclusion of the disclosure message but before charging commences?

The Public Staff recommended that intrastate 700 and 900 calls be subjected to a maximum length per call of 180 seconds as well as a maximum charge per call of $5.00. Public Staff thought that price disclosure messages at the beginning of intrastate 700 or 900 programs should be encouraged, but should not replace maximum charges and length requirements, and thought they may be difficult to administer.

The Attorney General also suggested that the Commission should consider whether to impose a cap on the maximum amount of 900 charges and whether a LEC should be prohibited from billing for any program which is not preceded by a price disclosure message.

The LECs were concerned about their ability to comply with imposition of either a maximum per minute call or maximum flat rate charge per call due to limitations in the companies' billing systems.

The IXCs strongly opposed ceilings or limiting the amount to be billed, with the exception of price caps at reasonable levels for children's programs. The IXCs were generally in favor of price disclosure messages.

4. Should LECs acting as billing and collection agents for 700 and 900 services be permitted to deny local service, disconnect local service or threaten to deny and/or disconnect local service for a subscriber's failure to pay said charges? If so, please describe the procedures under which denial or disconnection of local service should be allowed.

The Public Staff and Attorney General were both emphatic in stating that the LECs acting as billing and collection agents for 700 and 900 services should not be permitted to deny local service, disconnect local service or threaten to deny and/or disconnect local service for a subscriber's failure to pay these charges. The Public Staff indicated this should pertain to both interstate and intrastate services. The Attorney General stated such a practice should be declared an unfair and deceptive trade practice. The Attorney General stated that, moreover, the subscriber billed for 900 service must be notified of the LEC's lack of authority to disconnect for nonpayment of such charges in a manner approved by the Commission through an appropriate medium (statement on bill, bill inserts, time intervals, etc.).

The majority of the LECs thought the LECs acting as billing and collection agents for 700 and 900 services should be permitted to deny or disconnect local service for a subscriber's failure to pay 700 and 900 charges.

The IXCs thought that local service should not be denied or disconnected for failure to pay 700 and 900 charges and supported blocking.

5. Should an interexchange carrier (IXC) be permitted to suspend service to a long distance account if a customer fails to pay 700 or 900 charges. If so, please describe the procedures under which suspension of long distance service should be allowed.

The responses to No. 5 were basically the same as for No. 4 above with the LECs stating it should be addressed by the Commission and IXCs.

6. Should the LECs be allowed to block a customer's access to 700/900/976 services for failure of the customer to pay applicable charges? If so, under what terms and conditions should such blocking be allowed?

The Public Staff believed that the Commission September 7, 1990, order sets out appropriate terms and conditions. In addition, the LECs should be required to inform the customer in writing to file a complaint with the Commission to contest the 900 block.

The Attorney General expressed concern that mandatory blocking could be abused under certain circumstances and urged the Commission to proceed with caution.

The majority of the LECs thought the LECs should be allowed to block a customer's access to 700/900/976 services for failure of the customer to pay charges, with reluctance expressed concerning forced blocking. The IXCs supported non-optional blocking.

7. Should the LECs and IXCs be prohibited from considering the failure to pay 700, 900, and 976 charges when a LEC or IXC determines the customers's credit status?

The Public Staff and Attorney General supported prohibiting the LECs and IXCs from considering the failure to pay 700, 900, and 976 charges when a LEC or IXC determines the customer's credit status..

The majority of the LECs did not believe the LECs and IXCs should be prohibited from considering the failure to pay 700, 900 and 976 charges when determining the customer's credit status.

AT&T believes that failure to pay non-tariffed or premium 900 service charges should be treated separately from tariffed telecommunications service. MCI felt only charges occurring after the first episode of non-payment should have any effect on the customer's credit status. US Sprint thought that if local service should not be denied, then unpaid charges should not included in determining credit status of the customer.

8. Should the LECs be required to offer free blocking for 700 service in their tariffs?

The Public Staff believed that when 700 service is used to provide a 900-type offering, the LECs should be required to offer free blocking. If, however, technical limitations prohibit the LECs from selectively blocking those 700 numbers which are used to provide a 900-like offering, then the IXC offering the services should be required to offer blocking for those types of calls.

The Attorney General thought that, if technically possible, LECs should be required to offer free blocking of the kind described by Public Staff in its August 22, 1990, petition..

Generally, the LECs and the IXCs agreed that the LECs should be required to offer free 700 blocking only when 700 blocking can be done separately from 900 services and only in those instances where 700 service is used in a 900-like manner. Several companies pointed out that 700 service is generally used for the end-user's ability to verify his presubscribed carrier.

9. Should LECs acting as billing and collection agents for 700/900/976 programs be required to notify their subscribers of their authority regarding disconnection for nonpayment in a manner approved by the Commission? If so, what is the appropriate medium (statement on bill or bill inserts)? At what time intervals should customers be re-noticed?

The Public Staff recommended the notice be sent at least once a year, either placed as a statement on the bill or included as a bill insert.

The Attorney General suggested that the LECs should be required to give all consumers periodic notice of their lack of authority to suspend service for nonpayment of 700/900 charges, at least annually, and additional notice should appear on the face of any 700/900 bills rendered. Telephone bills which contain 700/900 billings should contain a statement that informs the consumer that his telephone service will not be disconnected for nonpayment of 700/900 charges but that normal debt collection procedures may apply.

Most of the companies agreed with or did not oppose this requirement. However, several companies expressed concern with possible customer abuse. Southern Bell believed its current denial notice, which states that the customer must pay all regulated charges in order to avoid disconnection is sufficent. Concord suggested notification could be in the form of a statement on the bill or a bill insert, and an additional measure could include a paragraph in the customer information section of the telephone directory and wording on the actual denial notice.

10. Should the LECs implementing the notice requirements described in paragraph 9 above be required to pass the costs associated with implementation on to 700/900/976 program subscribers instead of to their local telephone subscribers?

The majority of all parties believed these costs should be passed on to 700/900/976 program subscribers, directly or indirectly.

AT&T indicated that subscribers benefit from the ability of the LECs to bill for 900 service through additional billing and collection revenues. It would be illogical and unfair to charge sponsors for notice which works to their disadvantage, as well as impractical because there is no apparent way to pass costs on to 900 sponsors who are not themselves billing customers of the LECs. MCI stated it does not oppose having properly identified and quantified actual (not projected) costs of the notice requirement treated by the LECs as part of the costs of providing tariffed billing and collection service.

11. Should the LECs who act as billing and collection agents for 700/900/976 programs be required periodically to notify their subscribers, by bill insert, that such programs may be blocked at no extra charge? If so, at what intervals should said notice be accomplished?

The Public Staff and the Attorney General both believed that the LECs should be required to notify their customers by bill insert that such programs may be blocked at no extra charge. The Public Staff thought this notice could be provided at the same time and in the same manner as the notice regarding the LECs' authority for disconnection for nonpayment.

Some of the LECs stated they believed their current tariff and customer procedures are sufficient. Others felt that this information could be included in the bill inserts referred to in No. 9.

The responses from the IXCs varied from indifference to a recommendation that the LECs should provide annual notices of free 900 service blocking.

12. If a subscriber obtains 700/900/976 blocking, should the LECs require by tariff that any subsequent request that blocking be removed be made by the subscriber of record in person?

Both Public Staff and the Attorney General felt that blocking should not be removed until the subscriber makes the request in person.

The majority of the LECs and IXCs agreed that the request should be made by the subscriber of record but that the requirement of a personal visit would be burdensome to the subscriber and felt that notification in writing would be sufficient, with verification by the LEC, if necessary.

13. Should the LECs be authorized to hold a subscriber of record liable for any charges resulting from an unauthorized removal of blocking for 700/900/976 calls?

Neither Public Staff nor the Attorney General felt that the LEC should be authorized to hold a subscriber of record liable for any charges resulting from unauthorized removal of blocking for 700/900/976 calls.

Southern Bell, Citizens, Concord, Pineville, Randolph, Ellerbe and Mebane all thought the subscriber should be held liable. Carolina, GTE, and Central did not believe the customer should be held liable. Lexington and North State suggested the problem would be eliminated if proper procedures were followed which would include personal appearance of the subscriber if possible, with written authorization from the subscriber otherwise, with the LEC attempting to verify the authenticity of the request prior to removing the blocking.

MCI believed the customer should not be held liable but that mandatory blocking should be imposed again with more stringent requirements for future requests for removal of blocking such as in-person visits to the LECs office to sign the request. US Sprint thought the LECs should not be precluded from exercising legal remedies to address unauthorized removal of blocking for 700/900/976 calls.

14. If a local exchange customer makes a partial payment on a telephone bill which includes 700/900/976 charges, how should the payment be credited among the various amounts owed; i.e., local service, long distance service, federal subscriber line charge, 900 services, etc.?

The majority of the parties felt that any partial payments should first be applied to regulated services and then to non-regulated services.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

1. <u>AT&T's MultiQuest Tariff in Docket No. P-140, Sub 28, to Offer Intrastate 900-Service should be allowed on a provisional basis for two years, subject to certain modification</u>

The MultiQuest Service as proposed by AT&T consists of two components:

a) Communications service provided by AT&T to its customers who subscribe to the MultiQuest service. This permits a caller to complete the call by dialing 1-900 and a seven digit number to the MultiQuest customer's location. The rates for this service were contained in the proposed tariffs filed by AT&T.

b) "Premium billing" service provided by AT&T through the LECs on behalf of the MultiQuest customer. This billing service is provided under an unregulated and untariffed contractural agreement between AT&T and the MultiQuest customer. Under the "premium billing", the MultiQuest customer would have AT&T act as its agent and bill end users, through the LECs, for the services provided by the MultiQuest customer.

AT&T's MultiQuest Service also includes an extensive set of service standards which furnish the terms and conditions under which IPs may obtain the service. AT&T filed revised service standards on June 20, 1991. A copy of the revised standards are attached to this Order as Appendix A.

The larger question posited by the MultiQuest tariff filing is nothing less than whether 900 services should be permitted on an intrastate basis and, if so, under what terms and conditions. The Commission is all too aware of abuses of consumers and confusion surrounding 900 services. The Commission, Public Staff, and Attorney General have all received numerous complaints regarding certain 900 services. Abuses in certain 900 services are a nationwide problem.

At the same time, the Commission recognizes that many 900 services are valuable and beneficial. Certain medical and legal assistance programs, consumer products and services, education and information assistance, financial services, professional services, transportation and travel/leisure information services exemplify beneficial 900 services. The Commission does not believe it should thwart beneficial services such as these or deny the using public its choice in utilizing these services--provided this choice can be an informed choice.

Accordingly, after careful consideration of the filings in these dockets, the Commission believes that strong standards and guidelines are necessary to protect consumers from unfair and deceptive practices and to enable customers to make 900 calls based on informed choices, rather than confusion and lack of knowledge. If consumer problems surrounding 900 service are not abated by stringent standards, or if problems increase, then the Commission will re-evaluate the value of intrastate 900 service to North Carolina consumers.

Therefore, the Commission believes it is in the public interest to allow intrastate 900 service on a provisional basis only, for a period of twenty-four months from the date the tariffs become effective.

The Commission believes that AT&T's MultiQuest Service Standards are sufficient, with modification, for the Commission to allow AT&T to offer intrastate 900 service, subject to permanent standards adopted by the Commission. The modification to MultiQuest Standards which the Commission considers necessary is that an introductory message (preamble) informing callers of the program content and charges be included for all programs with the exception of Broadcaster and Call Counter, and that a preamble informing callers of the program content and charges be included for Broadcaster and Call Counter programs which exceed $2 per call.

2. Other IXCs desiring to provide intrastate 900 service should file tariffs to do so utilizing service standards comparable to AT&T's MultiQuest Standards, subject to permanent rules to be adopted by the Commission. This conclusion follows logically from the previous conclusion and needs minimal discussion. The wording of other IXC tariffs need not be the same, but the standards by which 900 service can be offered should be comparable. The Public Staff and Commission will closely examine each such filing to ensure compliance.

3. LECs should be allowed to offer billing and collection services for IXCs for 900 service. The first question asked of parties for comments was whether LECs should be permitted to offer billing and collection services for 900 services. All the LECs and IXCs believed that LECs should be permitted to perform such services. The Attorney General and Public Staff as a secondary position urged strigent guidelines if such a service were permitted.

The Commission notes that LECs currently bill and collect for interstate 900 services on behalf of IXCs and that this constitutes a growing market. The Commission, even if it were so disposed, is powerless to prevent this billing and collection for interstate calls. Moreover, the Commission has concluded herein that intrastate 900 service is in the public interest, subject to stringent safeguards and on an interim basis. It is a logical and appropriate corollary that billing and collection services should be available from LECs for intrastate 900 calls, subject to safeguards.

"Subject to safeguards" is the important phrase here. The overall thrust of all the comments received from all the parties was that the provision of 900 services requires strong safeguards. The AT&T service standards will serve as interim standards. The Attorney General's Proposed Rules Governing Telephone Billing and Collection for 900 services, perhaps modified in the light of comments, may furnish as appropriate basis for final rules to which individual IXC standards will be expected to conform.

Lastly, the Commission's decision to allow the MultiQuest and other 900 services implies that the AST will need modification. The Commission Order Suspending Tariff in Docket No. P-140, Sub 28, dated September 20, 1990, found that the current AST does not authorize billing and collection for 900 service. The AST will therefore require modification pursuant to the Commission's conclusion in these dockets.

4. Comments should be requested on the Attorney General's Proposed Rules Governing Telephone Billing and Collection for 900 services within 45 days of the issuance of this Order, with Reply Comments due 15 days thereafter. As noted above, the service standards of AT&T and comparable standards by other IXCs are intended to provide standards on an interim basis. For the purposes of final and uniform rules, the Commission believes that the Attorney General's Proposed Rules provide a good starting point for comment and discussion. In contradistinction to the Attorney General's view that these rules should be applicable to interstate as well as intrastate 900 services, the Commission understands and interprets these rules for the purposes of these dockets to be directed toward the intrastate provision of 900 service, except as to matters dealing with cut-off of local service and derivative matters.

Accordingly parties are requested to comment on these proposed rules. Parties recommending the revision of such rules should propose alternative language in the same format as the proposed rules are presented. Parties contesting or supporting the Commission's view of its jurisdiction over 900 services as stated above are invited to submit comments on this issue as well.

IT IS, THEREFORE, ORDERED as follows:

1. That AT&T refile its MultiQuest tariff, with the associated standards incorporated into that tariff, with language consistent with the terms of this Order.

2. That any IXC desiring to offer 900 services file a tariff, together with associated standards incorporated into that tariff, which is comparable to the revised tariff filed by AT&T.

3. That the LECs coordinate among themselves to revise the AST to allow billing and collection for 900 services offered by IXCs and submit same for approval no later than August 1, 1991.

4. That the provisions of Ordering Paragraph No. 1, 2, and 3, of the Spetember 7, 1990, Order in Docket No. P-100, Sub 111, forbidding local cut-off for unpaid 900 or similar services, outlining procedures, and forbidding intrastate long distance cutoff by IXCs for unpaid 900 or similar service continue in force pending further Order.

5. That all parties desiring to comment on the Attorney General's Proposed Rules Governing Billing and Collection for 900 services attached to this Order as Appendix B, do so within 45 days of the issuance of this Order with reply comments due 15 days thereafter. Parties recommending revision of such rules shall propose alternative language in the same format as the proposed rules are set out.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

(For Appendices see Official Copy of Order in Chief Clerk's Office.)

DOCKET NO. P-100, SUB 112

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Tariff Filing to Restructure Interexchange Private Lines and Southern Bell Telephone and Telegraph Company's Local Private Line and Special Access Services	) ORDER DENYING) TARIFF WITHOUT) PREJUDICE

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, May 29, 1991

BEFORE: Chairman Robert O. Wells, Presiding; and Commissioners Julius A. Wright and Charles H. Hughes

APPEARANCES:

For Southern Bell Telephone and Telegraph Company:

A. S. Povall, Jr., General Attorney, Southern Bell Telephone and Telegraph Company, Post Office Box 30188, Charlotte, North Carolina
and
Mary Jo Peed, General Attorney, Southern Bell Telephone and Telegraph Company, 4300 Southern Bell Center, Atlanta, Georgia 30375

For Carolina Telephone and Telegraph Company:

Jack H. Derrick, Senior Attorney, Carolina Telephone and Telegraph Company, 720 Western Boulevard, Tarboro, North Carolina 27886

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin IV, Byrd, Byrd, Ervin, Whisnant, McMahon and Ervin, PA, Attorneys at Law, Post Office Drawer 1269, Morganton, North Carolina 28655

For the Public Staff:

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For: The Using and Consuming Public

For the Attorney General:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

BY THE COMMISSION: On November 22, 1989, Southern Bell Telephone and Telegraph Company (Southern Bell) filed a proposed tariff which would:

(1) Change the structure and rates and charges for interexchange intraLATA private lines offered by the local exchange companies (LECs) throughout the state. Southern Bell contended this tariff change would reduce interexchange revenue to the intraLATA toll pool by $1.1 million;

(2) Change the structure and rates in Southern Bell's intraexchange, intraLATA private line tariffs. This produced a tariff increase of 58.2% for the nonrecurring charge for private line installation;

(3) Change the structure and rate of certain Southern Bell special access services. On net, this would produce an increase in revenues of $10,231 annually. There would be a 28.2% increase in nonrecurring special access charges offset by reductions in recurring rates.

The stated reason for the tariff changes was to establish uniform or comparable rates (rate parity) among the three services. The overall effect of the proposed restructuring at the time of filing was to increase Southern Bell's annual revenues by $1.4 million. By the time the matter came on for hearing, however, the amount of the estimated revenue increase was only approximately $360,000.

To soften the effect of the changes, Southern Bell proposed to delay the increases for recurring rates for six months, and then delay the increases for nonrecurring charges for another six months. The nonrecurring charge increases would be phased in, one-half of the increase to go in at 12 months, the other half to go in at 18 months.

The matter was brought before the Commission at the regularly scheduled Commission Staff Conference on November 5, 1990. At that time, Southern Bell and all affected LECs agreed to send letter notices to their affected customers. The Public Staff recommended that notice be sent with a 30-day comment period and the Commission so ordered. Within the 30-day period, the Public Staff received 19 letters opposing the changes, three general inquiries, and two statements in support of the revision, one from AT&T and one from a private line customer.

The Public Staff again brought the matter before the Commission at the regular Commission Staff Conference on February 25, 1991. The Public Staff recommended that the proposed tariffs be allowed to become effective as planned.

On March 15, 1991, the Commission issued an Order setting the matter for hearing, stating, "[a]fter careful considerations of the filings in this case, the Commission believes this matter should be set as a complaint hearing to determine the need for increased revenues." The Commission scheduled the matter to be heard May 29, 1991, and required Southern Bell to submit both a notice to affected customers for review and a "schedule of proposed rate decreases which would result in no impact on net income for use by the Commission in making its decision."

On May 28, 1991, Carolina Utility Customers Association, Inc. (CUCA), filed a written motion to compel discovery of Southern Bell's cost studies used in setting these private line rates.

A hearing in this matter was held on May 29, 1991. The Attorney General joined CUCA's motion to compel discovery of Southern Bell's cost studies used in setting the private line rates. After oral argument, the Commission issued a bench Order denying the motion. Southern Bell presented Mr. Thomas E. Allen, the company's manager responsible for tariff and rate issues with respect to the services in the private line and intrastate special access tariffs, to testify in support of Southern Bell's proposed restructuring of the private line and special access tariffs. Carolina Telephone and Telegraph Company (Carolina) presented the testimony of William E. Cheek, Director of Toll Revenues and Industry Relations, in support of its position. Neither CUCA, the Public Staff, nor the Attorney General presented any witnesses.

At the hearing, Southern Bell, through its witness Allen, testified that the main purpose of the private line restructure filing was to establish comparable rates for comparable services and that the approval of the restructured tariff would permit Southern Bell to eliminate rate disparities that exist between private line and special access services as well as provide a common rate structure. Such a restructure would eliminate customer confusion and would be beneficial to customers because the tariff would be easier to understand. Mr. Allen testified that the proposed recurring rates reflected the relative value of the service and provided a contribution above cost and that the nonrecurring rates were set at cost rounded up to a whole dollar amount.

Mr. Allen testified that the main benefits of this filing were that by establishing rate parity, all subscribers to the same type of dedicated service will pay the same rate in North Carolina and that the simplified tariff structure will also be beneficial to customers because it is easier to understand.

Mr. Allen further testified that other elements of the restructure included transfer of tie lines and extension channels, except for type 2110 local channels, from the General Subscriber Services Tariff to the Private Line Tariff; availability of Local Area Data Service (LADS), and Dataphone Digital Service (DDS) in the Private Line Tariff, as well as the telegraph grade service in the Special Access Tariff, only to those customers who currently subscribe to those services, and marginal increases for these services; and a withdrawal of wideband analog and wideband data services as there are no current customers to these services.

Mr. Allen also testified that an "Incremental Forward Looking Cost Methodology," which anticipates what new technologies will be in the network and to what degree they will be deployed at some point in the future, was used in pricing the services in this filing.

Mr. Allen further testified that the restructure filing was made in November 1989 with the intent that there would be a corresponding filing made that would reduce revenues in an amount at least equal to the estimated increase in revenues from the restructure filing. That corresponding filing was made in December 1989 and went into effect on May 1, 1990, with an estimated revenue reduction effect of slightly over $2,000,000 on an annualized basis.

On behalf of Carolina, Mr. Cheek testified that it was Carolina's belief that the private line restructure filing grants significant revenue offset benefits to Southern Bell that have not been available to the smaller independents. The Bell proposal lowers rates on competitive intraLATA routes while raising rates on captive local private line customers. He indicated that Carolina is not opposed to this provided that the Commission provides equitable treatment to all the LECs, and requested that the Commission consider revenue offsets in future filings by other LECs to ensure equitable treatment results.

At the conclusion of the hearing the Chair requested proposed orders from the parties 30 days after receipt of the transcript.

On July 8, 1991, Southern Bell filed information concerning the settlement impact of Southern Bell's private line restructure filing upon Carolina as instructed by the Chair in the hearing. This settlement impact is approximately $260,000.

On July 12, 1991, Southern Bell filed a Proposed Order. Briefs were filed by Carolina on July 9, 1991, and July 10, 1991, by the Attorney General and CUCA.

A reply brief was filed by Southern Bell on August 12, 1991.

In his brief filed July 10, 1991, the Attorney General argued that the Commission lacks sufficient evidence to allow these tariff increases to go into effect and that, even apart from the lack of competent evidence to support a tariff increase, these requested tariffs and their offsets raise serious questions about toll pooling and cross-subsidies.

The Attorney General requested that at the very least the proposed increases in non-recurring charges for private line tariffs not be allowed to go into effect absent some more substantial showing of the costs involved.

In its brief, filed July 10, 1991, CUCA contended that Southern Bell's proposal to alter the rates for the various recurring and nonrecurring components of its private line and special access tariffs was not adequately supported by the competent, material, and substantial evidence in the present record and should be rejected without prejudice to Southern Bell's right to refile for such a restructuring based upon a properly developed embedded cost study.

In its Brief filed July 9, 1991, Carolina stated that the Southern Bell proposal will lower rates on competitive intraLATA routes and raise rates for captive local private lines but that Carolina does not oppose this arrangement provided the Commission provides equitable treatment to all LECs. In addition, Carolina accepts the underlying premise of the Southern Bell proposal, but believes the Commission should be aware of and should address the pooling issue.

Southern Bell, in its Reply Brief filed August 12, 1991, stated among other points, that because Southern Bell has shown by "uncontroverted evidence" there are no increased revenues, the issue then becomes whether the private line restructure tariff rates are just and reasonable. Moreover, there is no legal requirement for the Commission to find changed circumstances or changed costs, nor is there any requirement other than to find the proposed rates reasonable.

WHEREUPON, the Commission makes the following

FINDINGS OF FACT

1. This matter is a tariff filing by Southern Bell to revise certain items of its tariff, as described above, for private line and special access services. The Commission has jurisdiction to hear and resolve such matters under G.S. 62-2, 62-32, and 62-134.

2. The matter of this private line restructure filing was set down as a complaint proceeding to determine the need for increased revenues under G.S. 62-137.

3. Southern Bell did not carry its burden of proof that these tariff revisions should be allowed.

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

These are jurisdictional matters, uncontested by the parties.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

While as an abstract matter, the Commission may not necessarily disagree with a tariff restructuring to establish comparable services, eliminate rate disparities, and provide a common rate structure, in this specific instance, the Commission must agree with the Attorney General and CUCA that the evidence presented by Southern Bell in support of its restructuring proposal is neither sufficient nor convincing.

Southern Bell's case for a rate increase was largely based on an "incremental forward-looking cost methodology" study. This study was not placed into evidence by Southern Bell nor was it conducted by Southern Bell. (The BellSouth Private Line Cost Group was said to have done the study). Witness Allen, Southern Bell's <u>only</u> witness, did not have a detailed knowledge of the study. What the Commission knows about the study can only be gleaned from Mr. Allen's testimony and cross-examination. This is not satisfactory. The Commission thus has no evidentiary basis on which to rule in Southern Bell's favor.

While the Commission notes that the Public Staff reviewed the study and recommended approval of the increases at the February 11, 1991, Regular Commission Conference, the Commission also notes that the Public Staff did not sponsor the study or present a witness at the hearing.

It is true that the Commission denied CUCA's Motion for Discovery to obtain the cost study. The Commission notes that CUCA's motion was filed the day before the hearing, and granting it would have delayed the hearing. CUCA should have filed its motion in a more timely fashion. Even so, it is not CUCA's or the Commission's responsibility to ensure that Southern Bell introduces competent evidence in support of crucial elements in its case. Southern Bell could have, on its own motion, placed the study into evidence but it chose not to do so. Furthermore, Southern Bell resisted the study being placed into evidence.

As for the rest of the proposed revisions, the Commission believes that insufficient evidence was presented by Southern Bell to justify these changes and "marginal increases." The Commission also believes that the impact on the toll pool of an approximate $900,000 decrease lends a degree of additional justification to the denial of the proposed filing.

IT IS, THEREFORE, ORDERED that Southern Bell's proposed private line tariff filing in this docket be denied without prejudice to refiling in the future.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

Commissioner Charles H. Hughes concurs.

DOCKET NO. W-100, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by the Public Staff for a Modification to the Rules and Regulations Governing the Filing and Conduct of General Rate Cases for Large Water and Sewer Companies	RECOMMENDED ORDER ADOPTING REVISIONS TO NORTH CAROLINA UTILITIES COMMISSION RULES AND REGULATIONS

BY THE HEARING EXAMINER: On March 1, 1990, the Public Staff filed the above-referenced petition. On May 2, 1990, the Commission issued Order Instituting Rulemaking Proceeding wherein all Class A and B water and/or sewer utilities operating in North Carolina, and all other interested parties, were requested to file comments to the Public Staff's proposed rule changes. The Hearing Examiner issued Order Requesting Reply Comments and Additional Comments on August 17, 1990, wherein all interested parties were given the opportunity to file reply comments to the comments filed pursuant to the Commission's May 2, 1990, Order. In addition, the parties were requested to file comments on the additional items listed below:

1. Should the proposed rule changes apply to all Class A and B Water Utilities as classified in the 1984 National Association of Regulatory Commissioners System of Accounts or should some other classification be used? For instance, would it be appropriate to apply the rule changes only to water companies with annual operating revenues in excess of $700,000?

2. Would it be appropriate to require the effected companies under the proposed rule to file written testimony 45 days before the public hearing, thereby allowing time to establish issues as a result of the Public Staff audit? Would this approach be better than requiring the Companies' testimony to be filed with the Form W-1 filing?

3. Should the wage information required under item number 17 of the proposed Form W-1 filing be treated as confidential information? If treated as confidential, what measures should be implemented to protect this information?

4. Should the Stockholders Report for private companies required under item 16 of the proposed Form W-1 filing be treated as confidential information? If treated as confidential, what means should be implemented to protect this information?

5. Would it be appropriate to show only the North Carolina regulated operations for the financial statements required in item 1?

The Hearing Examiner will now review the comments filed by the parties in this matter.

Should the proposed rule changes apply to all Class A and B Water Utilities as classified in the 1984 National Association of Regulatory Commissioners System of Accounts or should some other classification be used? For instance would it be appropriate to apply the rule changes only to water companies with annual operating revenues in excess of $700,000?

Heater Utilities, Inc. (Heater) recommended the proposed rule changes, if any, should apply only to water companies with annual revenues in excess of $750,000. Heater further replied that the record keeping required by the proposed W-1 would be extremely burdensome and expensive for water utilities and their customers.

Carolina Water Service Inc. of North Carolina (CWS) stated that the proposed rule changes should apply to all water companies without regard to size, but noted that some of the information required in the proposed W-1 may be applicable only to larger water companies. CWS asserted that a separate set of rate case rules that accommodates smaller companies will result in the continued proliferation of unprofessional and undercapitalized water systems.

The Public Staff responded to this question by stating that, whatever criteria are employed, there is an arbitrary element in the selection of companies. The NARUC A and B Classifications were employed in the Public Staff's initial filing in order to maintain a parallel with the treatment of electric, telephone, and natural gas companies in the current rules. The Public Staff stated no opposition to other reasonable criteria and estimated that a cutoff of $500,000 operating revenues would bring eleven companies under the rule.

No other party filed a response to the Hearing Examiner's Order of August 17, 1990. However, several companies filed comments in response to the Commission's Order dated May 2, 1990, that indirectly impacts on this question of what companies, if any, should be brought under the proposed rule.

The Carolinas Chapter of National Association of Water Companies (CCNAWC) asserted that Class A and B water companies are not generally properly equipped to deal with the proposed NCUC form W-1 filing requirements. The CCNAWC further asserted that the requirements would increase cost and prohibit many companies from filing for rate relief unless they contract for expensive consulting services and hire additional personnel, thereby increasing costs to the companies. Based on this assertion, the CCNAWC recommended that the proposed rule requiring the filing of NCUC Form W-1 be rejected in its entirety.

Hydraulics, LTD (Hydraulics) asserted that the proposed data requirement would substantially increase costs that would be passed on to its customers. Hydraulics estimated this increase in costs to be approximately $75,000 annually.

The Attorney General agreed that rate case filing requirements for large water and sewer companies should be made more stringent and that the public Staff's proposed modification to rules governing the filing and conduct of general rate cases for these companies is appropriate. The Attorney General further noted that the vast majority of water and sewer companies are small and their rate case filings can be resolved expeditiously on the basis of the standard form application and subsequent accounting and operational audits.

Duke Power Company (Duke) filed general comments stating that the proposed changes require the filing of large amounts of information and therefore will require the expenditure of additional resources that will cause the effected utility's cost of service to increase. Duke also filed specific comments on the wording of the proposed rule changes. These comments will be addressed subsequently in this Order.

The Hearing Examiner has given much consideration to the issue of what water and sewer companies should be included under the proposed rule changes. It is clear, as pointed out by the Attorney General, that general rate case filings of large water and sewer companies require extensive discovery and data collection after the general rate case filing. This discovery is needed by the investigating parties to fairly review the rate case application and to therefore make reasonable recommendations to the Commission. This discovery is a burden to both the utility and the investigating party, but is clearly necessary in order that ultimately the Commission be able to make fair and reasonable decisions concerning the proposed general rate case increase.

Based on an indepth review of this matter, the Hearing Examiner concludes that the proposed rule changes regarding the filing of Form W-1 with a general rate case application should be applicable to water and sewer companies with annual revenues equal to or greater than $750,000. The Hearing Examiner notes that these requirements should result in a more orderly and efficient discovery process related to general rate case filings by said companies. The Hearing Examiner further notes that the required information, except as noted below, is needed for appropriate general rate case review and should not be unfairly burdensome to the effected utilities. In fact, most of the required information, except as noted below, should be readily available to the companies under prudent management.

Before going on to the next issue addressed in the Hearing Examiner's Order of August 17, 1990, the Hearing Examiner wishes to discuss here an issue embodied in what data will need to be provided by the effected water and sewer companies. This issue is whether each company should be required to file data on a total system basis or for each system operated by the company. Generally, the commenting water and sewer companies have asserted that system specific reporting requirements are too burdensome and costly. For instance, Heater notes that it owns 110 systems that average 75 customers per system. Heater further notes that it does not maintain separate income statement accounts by system. In conclusion, Heater asserts that system basis data is too costly to maintain.

The Hearing Examiner notes that the Commission is currently considering the issue of uniform rates in Docket No. W-100, Sub 113. The Hearing Examiner further notes that currently most large water and sewer companies establish rates on a total company basis, thereby following a uniform rate structure. The Hearing Examiner is further aware that this practice has been questioned by some parties and is subject to investigation in the above noted docket.

Due to the uncertainty surrounding the uniform rate issue, the Hearing Examiner concludes here that it would be inappropriate to require system specific data at this time. This conclusion is made without prejudice to any party requesting further review of this matter after the Commission issues its Order in Docket No. W-100, Sub 113.

Would it be appropriate to require the effected companies under the proposed rule to file written testimony 45 days before the public hearing, thereby allowing time to establish issues as a result of the Public Staff's audit? Would this approach be better than requiring the Companies' testimony to be filed with the W-1 filing?

Heater responded to the above issue by stating that said proposal would be appropriate. The Public Staff stated that it would not object to said proposal provided it is combined with a requirement that any rebuttal testimony be filed within 10 days of the filing of the Public Staff's testimony. Heater noted that the current Commission policy of requiring rebuttal testimony approximately a week before the general rate case hearings is appropriate.

CWS stated that a complete list of the contested issues in a rate case cannot be established until after the Public Staff files testimony. Therefore, CWS concluded that moving the Company's requirement to file direct testimony from the filing date to 45 days prior to the hearing will not change the substance of that testimony.

In order that all parties have an opportunity to fairly review all testimony and in order to place the burden initially on the filing company it is essential that the utility file testimony prior to that being filed by the Public Staff. However, in order that the company's testimony be structured as closely as possible to address the issues of the case, it is better that said testimony be filed 45 days prior to the hearing, than at the time of the rate case filing. Additionally, the Hearing Examiner concludes that the utility should make every effort to file rebuttal testimony 10 days prior to the public hearing.

Should the wage information required under item number 17 of the proposed W-1 filing be treated as confidential information? If treated as confidential, what measures should be implemented to protect this information?

Heater responded to this item by stating that the information should be treated as confidential. Heater asserted that should this information become public information then there would be a significant negative impact on the morale of the Company's work force. Under Heater's proposal the wage information should be treated as proprietary in nature and kept in a separate confidential file maintained by the Commission in each rate case. All information filed with the Public Staff would also be maintained in a separate confidential proprietary file. If certain salaries are contested in a hearing, then that information would be a matter of public record.

CWS responded to this item by stating that employee wage information should be treated as confidential and that review should be subject to Commission approval, upon written request.

The Public Staff responded to this item and stated no objection to receiving information or documents under proprietary cover or protective order when appropriate. The Public Staff asserted that such claims can be handled on a case by case basis.

The Hearing Examiner has given this issue much consideration and concludes that the question of confidentiality of the wage information should be handled on case by case basis, subject to Commission review, as proposed by the Public Staff.

Should the stockholders report for private companies required under item 16 of the proposed Form W-1 filing be treated as confidential information? If treated as confidential, what means should be implemented to protect this information?

Heater responded that stockholders reports should be treated as proprietary information and maintained in a separate file, similar to that recommended for the wage information.

CWS asserted that stockholders reports of private companies are confidential and have no bearing on the ratemaking process.

The Public Staff response to this issue was the same as their response concerning the wage information, as spoken to above.

Based on a review of this matter, the Hearing Examiner concludes that the question of confidentiality of the stockholders reports for private companies should be handled on a case by case basis, subject to Commission review, as proposed by the Public Staff.

Would it be appropriate to show only the North Carolina regulated operations for the financial statements required in item 1?

Heater responded to this item by stating that it maintains only one consolidated balance sheet for its five corporations and jurisdictions and that it would be very costly to break out a separate North Carolina only balance sheet. Heater further asserted that its consolidated capital structure should be used to establish rates and that the preparation of a North Carolina only balance sheet would not improve the Commission's regulation of Heater.

CWS responded to this item by stating that comparative financial statements should only be required for the North Carolina regulated operations.

The Public Staff responded that the proposed Form W-1 should show North Carolina jurisdictional information unless something else is specifically requested. The Public Staff further noted that relevant nonjurisdictional information may be requested in the discovery process subsequent to the general rate case filing.

Based on the foregoing, the Hearing Examiner concludes that item 1 of the Form W-1 should show North Carolina jurisdictional information unless something else is specifically requested.

The Hearing Examiner will now review the comments filed by the parties regarding changes to the proposed rules and regulations, other than those specifically discussed above.

Duke Power Company recommends that the first sentence of Rule R1-17(d) should be changed to read inpart, as follows:

> Within thirty (30) days from the filing of any general rate case application by any electric, telephone, natural gas, water or sewer utility, such utility shall publish notice to its customers in newspapers having general circulation...

The Hearing Examiner concludes that this change to include sewer companies is appropriate.

Duke Power Company recommends that Rule R1-17(f)(1) should be revised to allow 20 days to file additional information. Based on a review of this matter, the Hearing Examiner is unpersuaded to make this change at this time.

The Public Staff proposes that the last sentence of Rule R1-17(a) should be revised to read as follows:

> All Class A and B electric, telephone, natural gas, water, and sewer utilities shall file written letters of intent to file general rate applications with the Commission thirty (30) days in advance of any filing thereof.

The CCNAWC noted that this change would improve the Public Staff's ability to schedule field investigations and simplify the hearing process by allowing additional time for communication between the company and the Public Staff prior to the hearing. Therefore, the CCNAWC supported this proposed rule change.

Similarly, Heater supported the requirement of filing a letter of intent at least 30 days prior to filing of a general rate case application. Heater, too, concluded that this rule will enable the Public Staff to improve the planning of the financial audits and field investigations.

CWS also supported this proposed rule change. CWS noted that providing the Commission with 30 days advance notice of a general rate case filing would enable the Commission and Public Staff to prepare for the anticipated workload increase.

Based on the foregoing, the Hearing Examiner concludes that the proposed revision to Rule R1-17(a) should be approved.

The Public Staff proposed that Rule R1-17(b)(12) should be revised to read as follows:

> (12) All general rate applications of Class A and B electric, telephone, natural gas, water and sewer utilities shall be accompanied by the information specified in the following Commission forms respectively:

For Class A and B Electric Utilities:

(a) NCUC Form E-1, Rate Case Information Report - Electric Companies

For Class A and B Telephone Utilities:

(b) NCUC Form P-1, Rate Case Information Report - Telephone Companies

For Class A and B Natural Gas Utilities:

(c) NCUC Form G-1, Rate Case Information Report - Natural Gas Companies

For Class A and B Water and Sewer Utilities:

(d) NCUC Form W-1, Rate Case Information Report - Water and Sewer Companies

This is the proposed rule change that would require water and sewer companies to file the Form W-1 information report discussed above. The Hearing Examiner has already concluded that water and sewer companies with annual revenues equal to or greater than $750,000 should be required to file this report with all rate case applications. Therefore, the Hearing Examiner concludes that the proposed rule change is appropriate, except that it should apply to all water and sewer companies with annual revenues equal to or greater than $750,000.

The Public Staff proposed that the first sentence of Rule R1-17(b)(13) be revised to read as follows:

> (13) Class A and B electric, telephone, natural gas, water and sewer utilities shall file with and at the time of any general rate case application all testimony, exhibits and other information which any such utility will rely on at the hearing on such increase.

Similarly, the Public Staff proposed that the fourth sentence of Rule R1-24(g)(2) be revised to read as follows:

> Class A and B electric, telephone, natural gas, water and sewer utilities shall file with and at the time of any general rate application all testimony, exhibits and other information which any such utility will rely on at the hearing on such increase.

As discussed earlier, the Hearing Examiner concluded that Class A and B water and sewer utility companies should file testimony no later than 45 days prior to the general rate case hearing. Therefore, the proposed rule changes should be revised to reflect this decision. The Hearing Examiner notes that it is not appropriate at this time to include in the revised rule that the utility must file rebuttal testimony 10 days prior to the general rate case hearing. However, the Hearing Examiner strongly encourages the water and sewer utilities to do so.

Based on the foregoing, the Hearing Examiner concludes that Rule R1-17(b)(13) should be revised to reflect the following as two additional sentences after the current first sentence:

> Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

Consistent with the above decision, the Hearing Examiner concludes that Rule R1-24(8)(2) should be revised to reflect the following as two additional sentences after the current fourth sentence:

> Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

IT IS, THEREFORE, ORDERED:

1. That the Rule revisions included on Appendix A be, and hereby, are approved upon the effective date of this Order.

2. That NCUC Form W-1, attached hereto, be, and hereby, is approved upon the effective date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of May 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

(Note: For Copy of NCUC Form W-1 Rate Case Information Report See Official Copy of Order in Chief Clerk's Office.)

APPENDIX A

Revisions to NCUC Rules and Regulations

1. Revise the first sentence of Rule R1-17(d) to read inpart, as follows:

   Within thirty (30) days from the filing of any general rate case application by any electric, telephone, natural gas, water or sewer utility, such utility should provide public notice to its customers in newspapers having general circulation...

2. Revise the last sentence of Rule R1-17(a) to read as follows:

   All Class A and B electric, telephone, natural gas, water, and sewer utilities shall file written letters of intent to file general rate applications with the Commission thirty (30) days in advance of any filing thereof.

3. Revise Rule R1-17(b)(12) to read as follows:

(12) All general rate case applications of Class A and B electric, telephone and natural gas companies, and of all water and sewer companies with annual revenues equal to or greater than $750,000 shall be accompanied by the information specified in the following Commission forms respectively:

For Class A and B Electric Utilities:

(a) NCUC Form E-1, Rate Case Information Report Electric Companies

For Class A and B Telephone Utilities:

(b) NCUC Form P-1, Rate Case Information Report - Telephone Companies

For Class A and B Natural Gas Utilities:

(c) NCUC Form G-1, Rate Case Information Report - Natural Gas Companies

For Water and Sewer Companies with Annual Revenues Equal to or Greater than $750,000:

(d) NCUC Form W-1, Rate Case Information Report - Water and Sewer Companies

4. Revise Rule R1-17(b)(13) to reflect the following as additional two sentences after the current first sentence:

Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

5. Revise R1-24(g)(2) to reflect the following as additional two sentences after the current fourth sentence:

Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

DOCKET NO. W-100, Sub 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition by the Public Staff for a Modification to the Rules and Regulations Governing the Filing and Conduct of General Rate Cases for Large Water and Sewer Companies	))))	ORDER AMENDING RECOMMENDED ORDER OF MAY 14, 1991

BY THE COMMISSION: On May 14, 1991, Hearing Examiner Jim Panton issued Recommended Order adopting Revisions to North Carolina Utilities Commission Rules and Regulations. On June 3, 1991, the Public Staff filed a motion requesting the Hearing Examiner to clarify the Recommended Order in regards to the filing requirements of expert testimony in general rate cases for water and sewer companies.

On June 13, 1991, the Carolina's Chapter of National Association of Water Companies (CCNAWC) filed exceptions to the Recommended Order of May 14, 1991. The CCNAWC asserts that the proposed NCUC Form W-1 would be too costly to implement for many companies that would result in higher rates to customers. Therefore, the CCNAWC proposed that the cost to ratepayers should be weighed against the benefit to the ratepayers of having the additional information, before the Commission adopts the proposed NCUC Form W-1. The CCNAWC requested oral argument on its exceptions.

On June 14, 1991, Hydraulis, LTD. filed a letter requesting the Commission to consider the cost increases related to the proposed Form W-1.

Oral Argument was scheduled for July 30, 1991, by Commission Order of July 9, 1991. The Public Staff and CCNAWC were represented by counsel at the Oral Argument.

At the Oral Argument, CCNAWC essentially reasserted the earlier position that the proposed NCUC Form W-1 is too costly to prepare. In response, the Public Staff stated that the information in the proposed NCUC Form W-1 was necessary to properly investigate general rate case filings of the affected companies.

The Commission has given this matter much consideration and concludes that the NCUC Form W-1 should be adopted, for the reasons contained in the Recommended Order of May 14, 1991. The Commission notes that these filing requirements are required by the Recommended Order of water and sewer companies with annual revenues equal to or greater than $750,000.

In order to facilitate compliance with the filing of the NCUC Form W-1, the Commission concludes that the requirement to file this data should be phased in over a period of time, so that the affected companies will have ample time to implement appropriate data collection systems. Therefore, the Commission concludes that the following schedule should be adopted for phase in of the NCUC Form W-1 data filing requirement:

Water and Sewer Companies with Annual Revenues	Implementation Date
1. Equal to or greater than $2,000,000	January 1, 1992
2. Equal to or greater than $1,500,000 but less than $2,000,000	July 1, 1992
3. Equal to or greater than $750,000 but less than $1,500,000	January 1, 1993

In order to reflect this decision, Rule R1-17 (b) (12) should be revised as shown on Appendix A, attached hereto.

At the oral argument, the Public Staff supported its proposed change to Rule R1-24(g)(2) as modified by the Recommended Order of May 14, 1991. The Public Staff suggested that the rule should be changed to reflect that all water and sewer companies file expert testimony in general rate cases 45 days prior to hearing. No party of record opposed this change. After careful consideration, the Commission concludes that R1-24(g)(2) should be changed, as recommended by the Public Staff.

At the Oral Argument, CCNAWC restated earlier concerns related to the need to maintain confidentiality of the employee wage data contained in Format 17 of the NCUC Form W-1. The Commission notes that these concerns are addressed on page 5 of the Recommended Order, wherein the Hearing Examiner concluded that the question of confidentiality of the wage information should be handled on a case by case basis subject to Commission review. Based on a review of this matter, the Commission reaffirms the Recommended Order's treatment of item 17 of NCUC Form W-1.

Upon review of the entire record in this matter, the Commission concludes that the rule changes included in the Recommended Order of May 14, 1991, should be adopted, except as modified herein above. All of the rule changes adopted by the Commission in this matter are shown on Appendix A. The Commission will issue further Orders in the future to implement further appropriate rule changes related to the phase in of the NCUC Form W-1 data filing requirement.

IT IS, THEREFORE, ORDERED as follows:

1. That the Rule revisions included on Appendix A be, and hereby, are approved upon the date of this Order.

2. That the NCUC Form W-1, attached to the Recommended Order of May 14, 1991, be and hereby, is approved and subject to the phase in plan contained herein this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

Revisions to NCUC Rules and Regulations

1. Revise the first sentence of Rule R1-17(d) to read inpart, as follows: Within thirty (30) days from the filing of any general rate case application by any electric, telephone, natural gas, water or sewer utility, such utility should provide public notice to its customers in newspapers having general circulation...

2. Revise the last sentence of Rule R1-17(a) to read as follows: All Class A and B electric, telephone, natural gas, water, and sewer utilities shall file written letters of intent to file general rate applications with the Commission thirty (30) days in advance of any filing thereof.

3. Revise Rule R1-17(b)(12) to read as follows:
(12) All general rate case applications of Class A and B electric, telephone and natural gas companies, and of all water and sewer companies filed on or after January 1, 1992, with annual revenues equal to or greater than $2,000,000 shall be accompanied by the information specified in the following Commission forms respectively:

For Class A and B Electric Utilities:
(a) NCUC Form E-1, Rate Case Information Report
Electric Companies

For Class A and B Telephone Utilities:
(b) NCUC Form P-1, Rate Case Information Report -
Telephone Companies

For Class A and B Natural Gas Utilities:
(c) NCUC Form G-1, Rate Case Information Report
Natural Gas Companies

For Water and Sewer Companies with Annual Revenues Equal to or Greater than $2,000,000:
(d) NCUC Form W-1, Rate Case Information Report -
Water and Sewer Companies

4. Revise Rule R-17(b)(13) to reflect the following as additional two sentences after the current first sentence:
Class A and B water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

5. Revise R1-24(g)(2) to reflect the following as additional two sentences after the current fourth sentence:
All water and sewer utilities shall file 45 days prior to the hearing on the general rate case application all testimony which such utility will rely on. Class A and B water and sewer utilities shall file with the application all exhibits supporting the general rate increase.

DOCKET NO. E-7, SUB 461

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Power Company for a Certificate of Public Convenience and Necessity Pursuant to G.S. § 62-110.1 Authorizing Construction of the Lincoln Combustion Turbine Station in Lincoln County, North Carolina	) ORDER GRANTING CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

HEARD IN: Courtroom #2, Lincoln County Courthouse, Lincolnton, North Carolina, on September 27 and 28, 1990, and in Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina 27602, on November 20 and 21, 1990

BEFORE: Chairman William W. Redman, Jr., Presiding, and Commissioners Ruth E. Cook, Julius A. Wright, Robert D. Wells, Charles H. Hughes, and Laurence A. Cobb

APPEARANCES:

FOR DUKE POWER COMPANY:

Steve C. Griffith, Jr., Senior Vice President and General Counsel, and William Larry Porter, Associate General Counsel, Duke Power Company, 422 South Church Street, Charlotte, North Carolina 28242-0001

Myles E. Standish, Kennedy Covington Lobdell & Hickman, Attorneys at Law, 3300 NCNB Plaza, Charlotte, North Carolina 28280

FOR THE PUBLIC STAFF:

Gisele Rankin, Staff Attorney, and A. W. Turner, Jr., Staff Attorney, Public Staff--North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For the Using and Consuming Public

FOR THE NORTH CAROLINA DEPARTMENT OF JUSTICE:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For the Using and Consuming Public

FOR INTERVENORS GEORGE CLARK, ET AL.:

Donnell Van Noppen III, Smith, Patterson, Follin, Curtis, James, Harkavy & Lawrence, Attorneys at Law, Post Office Box 27927, Raleigh, North Carolina 27611

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION, INC.:

Sam J. Ervin IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Attorneys at Law, Post Office Drawer 1269, Morganton, North Carolina 28655

BY THE COMMISSION: This proceeding was instituted on February 2, 1990, by Duke Power Company (Duke) filing information required under Commission Rule R8-61(b) pertaining to the proposed Lincoln Combustion Turbine Station. This filing was followed on July 27, 1990, by the filing of an application for a certificate of public convenience and necessity under N.C.G.S 62-110.1 to construct the Lincoln Combustion Turbine Station on a site in Lincoln County, North Carolina.

In the application for a certificate of public convenience and necessity, Duke proposes to construct sixteen simple cycle combustion turbine units capable of generating 1,165 MW. The site is located two miles west of Lowesville on an approximately 711-acre site. The units are designed to burn natural gas and fuel oil. Two five-million gallon tanks will provide long-term storage for the oil used to fuel the turbines. There will be a natural gas pipeline connection to the facility. The site will also include a 9½-acre storage pond with 125 acre-feet of useable capacity. The project's generation output will tie into Duke's transmission grid by a fold-in with the existing McGuire Longview Tie 230 KV line. Construction of the project is scheduled to begin in October 1991.

On July 31, 1990, a Notice of Intervention was filed by the Attorney General on behalf of the using and consuming public.

On August 1, 1990, Duke filed the testimony of Donald H. Denton, Jr., stating that the proposed construction conformed to Duke's most recent Least-Cost Integrated Resource Plan (LCIRP) approved by this Commission's Order dated May 17, 1990, and stating that since the construction of turbines was already included in its LCIRP, Duke did not need to file an update.

By Order of the Commission dated August 8, 1990, notice of the application was required to be published in a daily newspaper of general circulation in Lincoln County; and the Commission, on its own motion, set public hearings on the application to commence on September 27 and 28, 1990, at the Lincoln County Courthouse, Lincolnton, North Carolina, and in the Commission Hearing Room, Raleigh, North Carolina, on November 20 and 21, 1990. The Order stated that Duke would file testimony supporting its application on September 7, 1990, and would file additional testimony detailing its demand-side management evaluations and results by October 15, 1990. The Order provided the opportunity for intervention by interested parties.

On September 7, 1990, Duke filed the testimony and exhibits of Donald H. Denton, Jr. and Richard B. Priory.

On September 21, 1990, Duke provided proof of publication from the Lincoln Times-News and the Charlotte Observer indicating that notice of the application had been published in accordance with the Commission's Order.

On September 24, 1990, Petition for Leave to Intervene was filed on behalf of George Clark, Barbara Clark, Walter Clark, Allison Clark, Donald Fisher, Mary Fisher, Margaret Morrison Guillett, Boyd McLean, Jimmie C. Dellinger, Aaron Broach, and Christine Broach (hereinafter referred to as the Intervenors). Filed along with the petition to intervene was a Motion for Postponement of Hearings. The Commission issued an Order on September 26, 1990, denying the Motion for Postponement of Hearings insofar as it sought to postpone the hearings in Lincolnton on September 27 and 28, 1990. The Commission, however, provided an opportunity for the parties to respond to Intervenors' motion for postponement of the Raleigh hearing and for an additional hearing in Lincolnton. The Commission allowed the intervention of Intervenors at the public hearing in Lincolnton on September 27, 1990. A number of public witnesses testified in Lincolnton on September 27 and 28.

On October 2, 1990, the Attorney General filed a Motion Joining Intervenors' Motion for Continuance of the Raleigh hearing.

On October 4, 1990, a Petition to Intervene was filed by Carolina Utility Customers Association, Inc. An Order allowing intervention was issued by the Commission on October 8, 1990.

On October 5, 1990, Duke filed its Response to the motion for postponement of hearings and to the request for additional opportunity to comment in Lincolnton.

On October 10, 1990, a prehearing conference was held in Raleigh before a Hearing Examiner. The parties were represented, and an Order was issued on October 17, 1990, describing procedures to be followed by the parties at the Raleigh hearing.

On October 17, 1990, the Commission also issued its Order Denying Motion for Postponement of Hearing. The Order reaffirmed the intervention of the Intervenors. The Commission recognized that public notice had already been given and that postponement of the hearing in Raleigh would result in confusion to the public and a waste of resources. The Commission also recognized that G.S. 62-82 provides for the Commission to commence hearing applications promptly and to make its decisions with reasonable dispatch. Finally, the Commission denied the alternative request for an additional public hearing in Lincolnton in that the Commission had already held two public hearings in Lincolnton and numerous witnesses had testified.

Meanwhile, on October 15, 1990, Duke filed the testimony of Donald H. Denton, Jr., regarding demand-site evaluations.

Pursuant to the Commission's August 8, 1990 Order, all parties other than Duke were required to file testimony by November 5, 1990. On October 29, 1990, Intervenors filed a motion for additional time in which to prefile expert testimony, requesting an extension of seven days. Duke opposed this request in a response filed October 31, 1990. On October 31, 1990, the Public Staff requested that it be granted a two-day extension to prefile its testimony. On

November 2, 1990, the Commission issued Orders granting Intervenors an extension of time to and including November 13, 1990, to prefile testimony, and granting the Public Staff an extension of time to and including November 7, 1990, to prefile its testimony.

On November 7, 1990, the Public Staff filed the testimony of Dennis J. Nightingale and Danny P. Evans.

On November 13, 1990, Intervenors requested one additional day to file the testimony of Dr. Douglas Crawford-Brown. This request was subsequently granted by Commission Order of November 21, 1990. On November 13, 1990, Intervenors filed the testimony of Dr. Robert B. Williams. On November 14, 1990, the testimony of Dr. Douglas Crawford-Brown was filed.

The public hearing was held in Raleigh on November 20 and 21, 1990. At the conclusion of the hearing, the Commission directed the parties to file proposed orders on or before January 25, 1991.

During the course of the hearing, Intervenors made an offer of proof concerning certain confidential information. The Commission ordered that the offer of proof be submitted in a sealed envelope, and this was done by Commission Order of March 19, 1991. The Commission did not review this information in reaching its decision.

On November 19, 1990, the Attorney General filed a Notice arguing that the cost of the proposed plant is currently unknown and urging the Commission to delay a decision herein until a reasonable showing can be made as to the cost of compliance with air and water quality regulations. Duke filed a Response on November 30, 1990, and the Attorney General then filed a Request to Reply on December 12, 1990. These filings have been considered and are ruled on hereinafter.

Proposed orders and briefs were filed as ordered on January 25, 1991.

On February 1, 1991, Empire Power Company filed a Petition to Intervene in this docket. On February 8, 1991, the Attorney General filed a Position to the effect that he does not object to Empire's intervention. Duke filed a Response opposing intervention on February 12, 1991. Empire then filed a Request to Reply on February 15, 1991. The Commission issued its Order Denying Petition to Intervene on February 20, 1991.

The Public Staff filed a Motion for Reconsideration or Clarification on February 22, 1991, asking the Commission to either reconsider denial of intervention for Empire or "clarify in what docket a continuing review of the feasibility of the Lincoln County CT plant will occur." The Attorney General joined the Public Staff's Motion on March 4, 1991. By its March 4 filing, the Attorney General also requested leave to file a late-filed exhibit, a February 27, 1991 letter from the Air Quality Section of the North Carolina Department of Environment, Health, and Natural Resources, Division of Environmental Management (DEM) regarding pending air permit applications for the proposed Lincoln County plant and existing Duke plants. Empire also moved for reconsideration on March 4, 1991. Duke filed Responses to the Public Staff, the Attorney General, and Empire on March 5 and 8, 1991. Duke opposed the late-filed exhibit offered by the

Attorney General. Finally, Empire filed a Request to Reply on March 8, 1991. All of these filings have been considered by the Commission and are ruled on hereinafter.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT AND CONCLUSIONS OF LAW

1. Duke Power Company is a corporation organized and existing under the laws of the State of North Carolina, and is a public utility operating in North and South Carolina where it is engaged in the business of generating, transmitting, distributing and selling electric power.

2. Duke Power Company has properly made application to this Commission for a Certificate of Public Convenience and Necessity as required prior to commencement of construction of new generating capacity and related facilities at its proposed Lincoln Combustion Turbine Station; all required notices have been given and the necessary parties were present or had the opportunity to be present at the public hearings, including members of the public who desired to appear; hearings were held on September 27 and 28, 1990, in Lincolnton, North Carolina, and on November 20 and 21, 1990, in Raleigh, North Carolina; and Duke, the Public Staff, Attorney General, Intervenors George Clark, et al., CUCA, and members of the public presented their views concerning the subject application.

3. Based on the evidence of future need for electric power in the Duke service area, and the Commission's own independent analysis of future requirements for electric service to North Carolina, made under G.S. § 62-110.1 and 62-2(3a), and considering the interchange, pooling and purchase of power, use of demand-side options, including conservation, load management and efficiency programs, and other methods for providing appropriate, reliable, efficient and economical electric service, public convenience and necessity requires that Duke construct an additional 1,165 mW of electric capacity for operation beginning as early as 1994.

4. The use of simple cycle combustion turbines for the 1,165 mW capacity addition, based on Duke's Least-Cost Integrated Resource Plan as it relates to cost and efficiency, is appropriate.

5. Construction of the Lincoln Combustion Turbine Station is consistent with the Commission's plan for expansion of electric generating capacity in North Carolina which includes, among other documents, the Commission's Order Adopting Least Cost Integrated Resource Plans dated May 17, 1990.

6. Duke utilized a reasonable process to select the site for the Lincoln Combustion Turbine Station.

7. The proposed site for the Lincoln Combustion Turbine Station is appropriate.

8. The Commission finds the estimated construction costs of the Lincoln Combustion Turbine Station of $480,523,000 to $517,560,000 to be reasonable, recognizing that the actual cost will be dependent upon compliance with environmental regulations, the construction schedule, and other factors.

9. The Commission finds that a certificate of public convenience and necessity for the Lincoln Combustion Turbine Station should be issued, subject to reporting and opportunities for further review as herein provided.

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

The evidence for these findings of fact is contained in the verified application, the Commission's files and records regarding this proceeding, the Commission Orders scheduling hearings, and the testimony of witnesses. These findings of fact are essentially informational, procedural and jurisdictional in nature.

The Commission conducted public hearings in Lincolnton, North Carolina, on September 27, 1990, during the hours of 7 p.m. to 10:15 p.m., and on September 28, 1990, during the hours of 9 a.m. to 11:15 a.m. to hear from members of the general public. Lincolnton is 12 miles from the proposed Lincoln Combustion Turbine Station project site. There were 16 witnesses on September 27 and nine witnesses on September 28. Some of the witnesses were in favor of the project and some opposed the project. Those in favor of the project recognized that there was a need for capacity, that the plant would contribute to the economy, and that Duke was a good corporate citizen. Those opposed to the project cited the project's effect on air quality, traffic, and the character of the area.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3, 4, AND 5

The evidence pertaining to these findings of fact is set forth in Duke's Application, Rule R8-61 filing, and the testimony of Duke witness Denton, Public Staff witnesses Dennis J. Nightingale and Danny P. Evans, and Intervenors' witness Dr. Robert B. Williams.

NEED FOR ADDITIONAL CAPACITY

Witness Denton presented testimony to support the application for the certificate to construct electric generation facilities and to address Duke's least cost integrated resource planning. He testified that Duke had filed its Least Cost Integrated Resource Plan (LCIRP) on April 6, 1989, and its Short-term Action Plan on April 26, 1990. The Commission Order Adopting Least Cost Integrated Resource Plans dated May 17, 1990, approved the LCIRP presented by Duke, concluding that the plan should provide adequate and reasonable reserve capacity during 1990-2003.

Witness Denton also testified that Duke's least cost planning process tended to show that Duke's near term capacity addition needs are best met by peaking capacity, and that the best option to meet the peaking resource requirement is combustion turbines. Duke's LCIRP includes as capacity additions over 2,100 mW of new combustion turbine capacity during 1994-99. He stated that construction of the 1,165 mW Lincoln Combustion Turbine Station is an integral part of Duke's LCIRP and is consistent with the Commission's plan for expansion of electric generating capacity reflected in the Commission's May 17, 1990 Order.

Witness Denton further testified that growth in the service area continues to add peak electric demand to the Duke system. From 1974 to 1989, the Duke system peak demand grew at an average annual rate of 3.5%. The most recent forecast projected the 1990 system summer peak to be 14,452 mW and an average annual peak growth rate of 2.4% for the years 1990-2004. He testified that in order to meet customer demand, Duke is bringing on line the four-unit Bad Creek Pumped Storage Hydroelectric project, is refurbishing units in its Plant Modernization Program, and is relying on load reductions expected from Duke's demand-side management program.

Witness Denton testified that Duke's reserve margin will be below 20% in the years 1990 through 1993. He stated that this margin should be adequate in the near term given that there is surplus capacity in the Southeast which will be available on the spot market during that period. He also stated that a reserve margin below 20% is unacceptable in the long term. He contended that the capacity from the Lincoln Combustion Turbine Station is necessary to maintain the minimum planning reserve margin in 1994 and beyond.

Witness Denton also discussed Duke's efforts to purchase capacity from other sources. He stated that Duke is presently finalizing an agreement on a purchase of 200 mW, but that this would not affect the schedule for the Lincoln Combustion Turbine Station. He indicated that the approval of the Lincoln Combustion Turbine Station will help in future negotiations to purchase capacity from other sources by providing an approved alternative to such purchases.

Witness Denton discussed Duke's demand-side resources contained in the most recent Short-Term Action Plan filed in April 1990. The demand-side programs incorporate load reductions associated with existing programs as well as new programs. The existing programs consist of interruptible type programs that are designed to be activated during capacity shortage situations. The interruptible programs target residential water heaters and air conditioners, industrial processes, and customer owned standby generators. In addition, there are conservation programs which include lighting, insulation, heating, ventilation, and air conditioning systems. The new programs include the promotion of Residential High Efficiency Heat Pumps, Commercial Air Conditioning Load Control, and Standby Generators with backfeed capability. These programs are currently implemented in pilot project studies to validate program design assumptions and customer acceptance.

Witness Denton testified that the most recent demand-side evaluations included 54 options consisting of existing and new programs, addressing all customer and market sectors, for initial analysis. Following the economic tests and the risk-assessment test contained in its LCIRP process, 23 of the options were selected for inclusion in the LCIRP. In addition, six options are or will become pilot programs. He concluded that the cumulative impact of the 23 demand-side options results in an equivalent combustion turbine capacity of 945 mW in 1995 and 1,607 mW by the year 2004 as compared with the 1990 Short-Term Action Plan which reported 714 mW in 1995 and 879 mW by 2004. Even with this peak load reduction, the analysis shows the need for all 16 Lincoln combustion turbines in the 1994 to 1996 period and shows that reserves during this period will rise only slightly above the 20% minimum planning reserve margin.

Witness Evans presented the Public Staff's most recent independent peak load forecast for Duke, which projects the system summer peak to grow from 14,143 mW in 1990 to 19,729 mW in 2005, an average annual growth rate of 2.2%. He testified that the forecast used by Duke in this proceeding is based on essentially the same methodology as that used by the Public Staff. He expressed some concern about the way Duke models the electricity price effect, and he therefore viewed Duke's forecast with caution.

Witness Nightingale addressed Duke's most recent demand-side management (DSM) evaluations, the need for the Lincoln Combustion Turbines based upon both Duke's and the Public Staff's current peak load forecasts considering the Commission's minimum 20% reserve margin for planning purposes, and the Public Staff's position on Duke's request for a certificate of public convenience and necessity.

Witness Nightingale stated that Duke should be commended for the effort put forth to complete its new DSM evaluations in time for inclusion in this proceeding. He indicated that the increase in cumulative DSM capacity compared to the DSM capacity contained in Duke's April 1990 Short-Term Action Plan is significant. Witness Nightingale also pointed out that the Public Staff was extremely pleased with Duke's leadership in the area of DSM. While North Carolina has embraced load management and similar concepts for years, least cost integrated resource planning is now resulting in a broad range of new conservation and DSM programs. Many of the DSM programs adopted by Duke are new to most customers in this State.

Nevertheless, witness Nightingale expressed reservations about Duke's strategic sales programs. He pointed out that 11 of the 23 demand-side programs were strategic sales programs designed to increase the use of electricity during periods of low cost. He recommended that a study of the appropriate level of strategic sales programs be performed by Duke in its next DSM evaluation and that the study should address the potential problems of strategic sales programs, such as creating sales during peak loading periods.

Witness Nightingale also recommended that Duke's next DSM evaluation should look more to demand reduction programs and conservation programs geared to postpone or negate future capacity additions, and specifically the combustion turbine additions projected for 1997 and 1999 and the coal fired capacity additions projected for the years 2000 and 2001. He indicated that Duke had committed to increase its research and development efforts regarding demand reduction and conservation programs.

In reviewing Duke's application, witness Nightingale commented on the lack of nonutility generator (NUG) generation shown for the future. He testified that the Public Staff believes Duke should adopt a nonutility generation goal of 500 mW of NUG capacity additions by the year 2000. On cross-examination, he noted that any new NUG capacity would have to be cost justified on the Duke system and that it is not appropriate to show NUG capacity in reserve margin calculations until Duke has contracts in hand for nonutility generation.

In response to witness Nightingale, witness Denton testified that Duke does not have any objections to establishing a goal of aggressively pursuing nonutility generation. He stated that studies have been performed to evaluate the opportunities for installing cost-effective nonutility generation and that the studies found there is not significant generation available which is cost-effective on Duke's system.

Witness Nightingale testified that the 20% planning margin is a minimum and that the optimal reserve margin may be higher. He testified that his review of the need for the Lincoln combustion turbines, based upon both Duke's and the Public Staff's current peak load forecasts and the Commission's minimum reserve margin, indicated that all of the Lincoln capacity will be needed by the summer of 1997. He indicated that the difference in the Duke and the Public Staff forecasts primarily influences how many units are added in each year between 1994 and 1997. Based upon the information known today and Duke's commitment to strive to offset future generation additions by intensifying its DSM and nonutility generation efforts, the Public Staff recommended the issuance of a certificate of public convenience and necessity for the Lincoln combustion turbines.

Intervenor witness Dr. Williams testified that he examined Duke's and the Public Staff's 1989 and 1990 long-term forecasts of peak demand for electricity. The forecasts by Duke and the Public Staff predict an increase in the peak in every year during the forecast period. The 1990 Duke forecast, however, predicts higher peaks than do the others. Witness Williams concluded that Duke's 1990 forecast is not the most accurate predictor of Duke's peak demand in the forecast period. He raised three concerns. First, he was concerned that Duke's forecasting techniques over-emphasize an abnormal year such as the high peak that occurred in 1989. Second, he believed that Duke's economic variables did not adequately recognize current economic conditions and noted that the actual temperature adjusted peak demand for 1990 was below both the Public Staff's and Duke's forecasted peaks. Third, he was concerned about Duke's use of three separate variables reflecting the real price of electricity and Duke's forecast that the real price of electricity would decline during the forecast period.

In response to witness Williams' first concern, witness Denton testified that the January 1990 Duke forecast reflected an unanticipated growth in the industrial base and the earlier opening of schools in North Carolina. He stated that one of every three years, the peak system demand will occur after the schools open. He noted that the 1989 peak occurred in late August. Duke used 1988, not 1989, as the base year for the 1990 forecast because of the unusual growth in 1989.

In response to witness Williams' second concern, witness Denton testified that the 1990 temperature adjusted peak was 14,058 mW as compared to the 1990 Duke forecasted peak of 14,452 mW. He testified further that a deviation from the forecast in any one year is not unusual and not necessarily an indication that the forecast is incorrect. He stated that a forecast is based on averages and that the forecast is a 15-year forecast of average economic conditions under probable weather conditions.

In response to witness Williams' third concern about Duke's use of three separate variables on the real price of electricity, witness Denton testified that two of these three variables were zeroed out of the forecast which had the result of reducing the 1994 peak forecast by approximately 500 mW. He also testified that the real price of electricity has declined since 1987.

Witness Williams testified that Duke had not included nonutility generating capacity in its Lincoln combustion turbine evaluation. He testified that Duke is currently exploring purchases for the 1990's of 500 mW of peaking-type service available for purchase from 1993 to 1997 and 80-250 mW which may be available for purchase from 1995 to 1999. He noted that these resources were not included in Duke's plans for capacity additions. He concluded that if the additional nonutility generation and purchase power opportunities are added into the Public Staff's evaluation of the need for the Lincoln Combustion Turbines, reasonable reserve margins are predicted without addition of the Lincoln Combustion Turbines. On cross-examination, he acknowledged that NUG capacity should not be included as available if it was not firm capacity.

The Commission concludes that the need for near term peaking capacity is a part of Duke's Least-Cost Integrated Resource Plan as approved in 1990. The proposed 1,165 mW Lincoln Combustion Turbine Station is intended to fill the need for near term peaking capacity.

Among the fears expressed by some parties to the preceding was the view that Duke's real price of electricity may increase over the next few years rather than decrease or remain stable as projected by Duke. Such fears are based at least partially on Duke's ability to obtain annual rate increases through the fuel adjustment mechanism and the experience modification factor (EMF) procedure permitted by G.S. § 62-133.2, and on the potential for general rate increases in response to the impending commercial operation of the Bad Creek pumped storage station and perhaps other generating stations. If such real price of electricity does increase, the price elasticity impact of such increase may lower the rate of growth of Duke's peak loads.

Furthermore, the uncertainties surrounding the American economy at the present time preclude any easy assumption that the current economic downturn will be short lived. There are fears among some of the parties that Duke's load forecast does not adequately account for the possibility of a significant economic downturn in the near future. These fears are heightened for some by the fact that Duke's actual 1990 summer peak was significantly below the level projected in Duke's 1990 forecast, and that an abnormally high peak in 1989 may have unduly influenced the forecast.

Duke indicated that it had little reason to believe that acceptable purchased power or NUG generation would be available at reasonable prices. However, both witness Nightingale and Dr. Williams contended that Duke could obtain a greater amount of purchased power or NUG generation than was reflected in its 1990 forecast. The projected availability of purchased power or NUG generation hinges primarily on the level of certainty that such capacity will be firm capacity.

After analyzing all of the evidence, the Commission concludes that the Lincoln Combustion Turbine Station will be needed to provide generating capacity for Duke's North Carolina retail ratepayers at least by the late 1990's and very possibly as early as 1994. In view of the uncertainties surrounding the forecasted rate of load growth and the level of contribution to Duke's system from purchased power and NUG generation, the Commission anticipates that the commercial operation date of each individual combustion turbine unit contemplated for installation at the Lincoln Combustion Turbine Station will be timed in such a manner as to maintain Duke's system reserve margins as close as reasonably possible to the 20% minimum standard adopted by the Commission. However, the timing of each individual CT unit must also be consistent with cost effectiveness and other considerations contained in Duke's approved least cost integrated resource plan.

DUKE AGREEMENT RE: DSM AND NUG

The Public Staff pointed out to the Commission that it had reached an agreement with Duke shortly before the hearing in this proceeding. The Public Staff agreed not to contest the Certificate of Public Convenience and Necessity for the Lincoln Combustion Turbine Station and Duke agreed to strengthen its efforts in the demand side management (DSM) and NUG generation areas.

The Public Staff analyzed Duke's efforts to meet its needs with DSM and NUG generation and was greatly satisfied with Duke's DSM efforts. The Public Staff was especially pleased with Duke's leadership in the DSM area. It cited the increases in cumulative DSM capacity over those shown in Duke's 1990 short-term action plan, and increased spending proposed by Duke for DSM programs. Many of Duke's DSM programs are new to customers in this state.

The Public Staff and Duke reached agreement on two DSM policies: first, that Duke will move toward more balanced spending between load management and conservation programs; and second, that Duke will move toward a reduction in the number of "strategic sales" programs and related spending.

Duke acknowledged that more of its new spending on DSM programs is on load management than on conservation programs. Duke agreed to concentrate more of its research on cost effective conservation programs. It also agreed with the Public Staff that future DSM programs should aim towards forestalling construction of future generating plants.

The Public Staff was troubled by the number of "strategic sales" programs and the amount of spending on them. Duke assured the Public Staff that, as future generating plants draw closer, its least cost integrated resource planning (LCIRP) process will reject an increasing number of the strategic sales programs. The Public Staff advised that it was satisfied that Duke's LCIRP process will work as Duke has indicated. However, it indicated that if future LCIRP filings did not show reductions in the strategic sales programs, it reserves the right to request a review of the process.

The Public Staff is not as satisfied with Duke's efforts to encourage NUGs. To assure NUGs that Duke is serious about its interest in NUG development, the Public Staff recommended that Duke adopt a reasonable goal, such as 500 mW of NUG additions by the year 2000. The Public Staff pointed out that Duke has already achieved over 122 mW of its original goal of 127 mW of NUGs by the year 2001. It contends that since Duke has set specific megawatt goals in the past, it should be able to set such goals for future additions.

Duke did not agree to set a specific megawatt goal for NUG additions, but agreed to strengthen its NUG program. It has designated a central contact person to handle NUG inquiries, and it has set a goal of aggressively pursuing NUGs as a part of its LCIRP.

The Commission is of the opinion that the agreement between the Public Staff and Duke regarding DSM and NUG programs should be adopted herein. Duke's expansion of DSM programs and spending reflect a strong commitment to making its LCIRP work.

The Commission is further of the opinion that this proceeding is not the appropriate forum for setting a specific megawatt goal for NUG additions. Although NUG additions were discussed herein and were a consideration in the determinations made herein, further discussion is needed before a specific megawatt goal is established for NUG additions. New NUG additions will be closely monitored in future LCIRP filings and particularly in future generic hearings on the LCIRP process. Discussion of specific megawatt goals for NUG additions would be more appropriate within such LCIRP process.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding is found in the testimony of Duke witness Priory and the Intervenor's witness Crawford-Brown.

Witness Priory's Exhibit RBP-1 shows that Duke conducted a comprehensive siting study to identify potential locations for a combustion turbine facility on the Duke system. The study evaluated various site-specific costs and environmental impacts to arrive at an appropriate site. The methodology used was a screening approach starting with the Duke service area. Coarse screening criteria were developed to determine exclusion areas and preferred areas. The coarse screening criteria are listed below:

Proximity to load center

- Primary location in northeast part of the service area;
- Secondary location in the central to southwest part of the service area.

Water Availability

- Adequate water storage and source of recharge water;
- Location near large streams, rivers, and reservoirs preferred.

Permitting

- No existing air or water quality constraints.

Land Ownership
- Use of Duke Power properties where possible.

Pipeline
- Location within 15 miles of natural gas pipeline if possible.

Transmission System
- Proximity to 500, 230, or 110 KV lines.

Railroad
- Proximity to carrier lines.

Population
- Density exclusion limit of 400 persons per square mile.

PSD Class I Area
- A 10-kilometer buffer zone for all Prevention of Significant Deterioration (PSD) Class I areas.

Land Use
- Land use was reviewed to locate acceptable and unacceptable sites near lakes in Duke's service area.

Ten potential siting zones were identified from the coarse screening criteria. Within these zones, 53 preliminary sites were identified.

Twenty-seven of the 53 sites were studied in detail. Fine screening criteria were applied to the sites for development of site-specific costs and evaluation of environmental concerns. The fine screening criteria are listed below:

COST CONSIDERATIONS

Construction Costs
- Earthwork
- Railroad
- Gas Pipeline
- Buildings
- Switchyard
- Tanks
- Water Supply
- Engineering
- Support

Transmission Line Costs
- Construction
- Reliability

Land Acquisition Costs

ENVIRONMENTAL CONSIDERATIONS

Air Quality
- National Ambient Air Quality Standards (NAAQS)
- Existing Air Quality

Additional Considerations
- Endangered species
- Aquatic recreation
- Terrestrial recreation
- Water shortage area
- Water quality

After application of the fine screening criteria, six sites in North Carolina (including the Lincoln County site) and one site in South Carolina were selected for detailed evaluation. Two North Carolina sites were located in Rowan County and one each was located in Davidson, Rockingham and Stokes Counties. The South Carolina site was located in York County. These other sites were rejected based on site-specific costs and/or environmental impacts.

An area in Lincoln County was identified as the best site area. Witness Priory testified that the site is well suited when considering environmental aspects, costs, and fuel and transmission access. The specific site ultimately purchased was included in the Lincoln County area identified in the siting study. Although the site was not the first property within the Lincoln County area pursued by Duke, the site embodies all the characteristics which made the area attractive. Witness Priory stated that Duke's siting methodology focused on areas instead of specific parcels of property because it is difficult to identify property lines and willing sellers during the siting process. He testified that of the seven final sites, the Lincoln County site was chosen primarily because of cost. The incremental cost to develop the Lincoln County site was $7.183 million; the incremental cost of the York County site, which was also seriously considered, was $22.023 million.

Witness Priory acknowledged that Duke had expressed a preference for a site near large bodies of water in its coarse screening criteria because Duke was considering a number of technologies at that time, but that this criterion was not important with respect to simple cycle combustion turbines.

Witness Crawford-Brown testified on behalf of the Intervenors. He testified that Duke excluded areas with existing air quality problems in its siting process. Among the areas excluded were Mecklenburg County, because of carbon monoxide and ozone problems, and Gaston County, because of particulate problems. Duke also excluded areas within ten miles of its Allen, Marshall and Cliffside generating plants because of concern with sulfur dioxide emissions at those plants as estimated by Duke Power in a modeling study. Duke did not, however, exclude an area around its Riverbend plant, which is only six miles from the Lincoln Combustion Turbine site. Witness Crawford-Brown concluded that Duke's decision not to exclude a 10-mile area surrounding the Riverbend plant was not justifiable. Such an exclusion would eliminate the proposed Lincoln County site from consideration. In addition, he predicted that prevailing wind directions will transport emissions from the Marshall and Allen plants toward the Lincoln Combustion Turbine Station site and that if the exclusions areas around those plants were adjusted to reflect transport patterns and prevailing winds, the exclusion area around the Marshall plant would exclude the Lincoln Combustion Turbine Station site.

In response to cross-examination, Dr. Crawford-Brown testified that he was not qualified to talk about economic factors resulting from the Clean Air Act, and he acknowledged that "the manner in which the Clean Air Act will be administered in North Carolina is not established." He also testified that the Clean Air Act will be a "consideration for the entire range of facilities which Duke Power operates," and that Duke could "leave the LCTS entirely as it is and simply reduce emissions from some other facility." He concluded that "there is a good possibility that the Clear Air Act would have no impact whatsoever on LCTS" and would not predict the probability of any action resulting from the Clear Air Act.

With respect to these matters, Duke witness Priory testified that the three exclusion areas around Marshall, Allen, and Cliffside were chosen because the existing emissions in those areas were close to national ambient air quality standards based on Duke's modeling results in 1980. An analysis was performed to see how close a new source could be located to the existing plants without affecting air quality at the existing plants. It was determined that combustion turbine emissions outside a ten-mile radius from the new source would not cause a significant impact on the air quality in the vicinity of the existing plants. The location of the site was not known at the time Duke established the coarse screening criteria, and a ten-mile circular exclusion area was determined to be sufficient. The exclusion area was used to assure that the new source would not cause the existing plants to exceed the national ambient air quality standard. With respect to Duke's failure to draw an exclusion area around Riverbend, witness Priory testified that a 1980 study, Exhibit DCB-2, was used to draw the exclusion areas. The study shows maximum concentrations of sulfur dioxide for each plant based on 3-hour averages and 24-hour averages. Exhibit DCB-2 shows maximum 3-hour concentrations of sulfur dioxide at Marshall as 1134 micrograms per cubic meter, Allen as 1301 micrograms per cubic meter, Cliffside as 1542 micrograms per cubic meter, and Riverbend as 1022 micrograms per cubic meter. The National Ambient Air Quality Standard for the maximum 3-hour concentration of sulfur dioxide is 1300 micrograms per cubic meter. Based on this data, witness Priory stated that Duke elected to exclude areas around Marshall, Allen, and Cliffside. The Riverbend maximum 3-hour concentration was lower than those at Marshall, Allen, and Cliffisde. The Riverbend maximum 24-hour concentration was higher than at Marshall. However, Priory testified that Duke was not concerned with 24-hour concentrations in siting the Lincoln Combustion Turbine Stations because the Lincoln Combustion Turbine Station will be a peaking station and is not expected to run for long periods of time.

The Commission has held that a complainant challenging the siting of an electric transmission line must show that the utility's site selection was arbitrary and unreasonable in order to prevail. Gwynn Valley, Inc. v. Duke Power Company 78 Report of NCUC Orders and Decisions 186 (1988); Kirkman v. Duke Power Company, 64 Report of NCUC Orders and Decisions 89 (1974). These were complaint cases, and the burden of proof was on the Complainant. The present docket is a certificate proceeding pursuant to G. S. 62-110.1 and the burden of proof is on the utility. G.S. 62-110.1 provides that a utility must obtain a certificate that public convenience and necessity requires, or will require, construction of a new generating facility. The statute sets forth no specific requirements as to the siting process of new generating facilities. The purpose of the statute is to prevent costly overbuilding of generating facilities, and environmental concerns are generally left to other regulatory agencies. State ex rel. Utilities Commission v. High Rock Lake Association, 37 N.C. App. 138, 245 S.E.2d 787, cert. denied, 295 N.C. 646, 248 S.E.2d 257 (1978). Though "not at the heart of the regulatory process" under G.S. 62-110.1, the Commission recognizes that environmental concerns are relevant to the extent they affect the cost and efficiency of a proposed generating facility. Id. The Commission also recognizes its responsibility under the State Enviromental Policy Act and specifically under G.S. 62-2(5) "to encourage and provide harmony between public utilities, their users and the environment." The Commission has considered all of the siting and enviromental concerns raised by the evidence. The Commission concludes that Duke has the burden of proof to show that its siting process was reasonable and that the site proposed for the new generating facility is an appropriate one.

Based on the evidence presented, the Commission concludes that Duke has conducted a thorough and reasonable siting process. Duke applied coarse screening criteria to determine exclusion areas where it would be difficult to place a plant and preferred areas which would tend to lower the cost of the plant. Duke then applied fine screening criteria to determine site-specific costs and environmental concerns. Duke selected the Lincoln County site based on the siting criteria which include costs considerations.

Intervenors' witness Crawford-Brown raised several concerns with the siting process. First, he contended that Duke should have drawn an exclusion area around Duke's Riverbend plant which would have eliminated the Lincoln County site. The primary basis for this contention is the fact that Riverbend's 24-hour sulphur dioxide concentrations are above those at Duke's Marshall plant around which Duke drew an exclusion area. Duke's evidence tended to show that it was not concerned with the 24-hour concentrations because the Lincoln County facility will be a peaking station and will not run for long periods of time. Witness Priory stated that the exclusion areas were based upon three-hour concentrations, and the Commission notes that the Riverbend three-hour emissions are below those at Marshall. Witness Crawford-Brown also contended that Duke's circular exclusion area around Marshall should have been drawn to reflect the prevailing wind directions to insure that emissions from the Marshall station would not affect the combustion turbine site. However, witness Priory testified that the purpose of the exclusion area was not to protect the combustion turbine site but to protect air quality levels at Duke's existing plant sites. The Commission concludes that Duke's exclusion areas were drawn in a reasonable manner.

Witness Crawford-Brown's other major concern with the siting process was the effect of the new Clean Air Act. The Commission notes that this Act became law well after the site selection process was completed. Furthermore, the witness stated that it will be a long time before the implications of the Act can be assessed and that the Act may have no impact whatsoever on the Lincoln County site. The Commission is concerned with the effect of air quality regulations on the site, as discussed later in this Order. Subject to that discussion, the Commission finds from the evidence that Duke's site selection process was reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony of Duke witness Priory, Intervenors' witness Crawford-Brown, and the public witnesses.

Turning to the appropriateness of the site chosen, the evidence tends to show that the project site is located in Lincoln County on State Road (SR) 1511, approximately two miles west of Lowesville. The site is adjacent to a large, active commercial quarry. Other communities surrounding the project include Lincolnton (12 miles west), Gastonia (14 miles southwest), Charlotte (18 miles southeast), and Davidson (11 miles northeast). Lake Norman and the Catawba River are three miles east of the project. The project site borders or includes portions of Anderson Creek and Killian Creek. Forney Creek is nearby. The project site consists of approximately 711 acres. Approximately 50% of the site is agricultural fields planted with pine seedlings; and the reminder is second-growth hardwoods, pines or mixed pine/hardwood stands. Access to the project site is by SR 1511, which connects N.C. Highways 16 and 73. This road will provide access for all work force and material deliveries during construction as well as for plant staff, material deliveries, and fuel oil shipments during operation.

Witness Priory testified that comprehensive studies were performed to evaluate the existing environmental conditions and the environmental impacts of construction and operation of the Lincoln Combustion Turbine Station. Studies included measurements of the chemical and physical characteristics of Killian, Forney and Anderson Creeks. Aquatic macroinvertebrates and fish were sampled and identified from the creeks. The samples were typical of Piedmont streams impacted by agricultural and moderate residential development. Terrestrial flora and fauna were also surveyed. No rare or endangered plant or animal species or habitat for such species was found to occur on the site. The existing air quality was evaluated based on information from ambient air monitoring performed by the State Division of Environmental Management. Witness Priory concluded that the existing ambient air quality at the project site is well below National Ambient Air Quality Standards.

Witness Priory stated that the environmental effects of site construction will be minimal. With respect to water quality of streams bordering the site, some temporary effects due to sediment from erosion during grading activities are expected. These effects will be minimized by the Sedimentation and Erosion Control Plan, which will include an undisturbed vegetation buffer between the construction site and the streams. Impacts of siltation on aquatic macroinvertebrates and fish will be minimized by erosion control measures. Terrestrial impact will consist of the permanent clearing of approximately 100 acres of mixed hardwoods, pines, shrub, and pasture land. The effect on wildlife on the site will be the loss of some upland game habitat. Effect on wildlife outside the 100 acre area of immediate construction will be minimal and temporary. Air quality impacts during construction should be minimal and will be in accordance with permits issued by appropriate state agencies.

Witness Priory testified that the environmental impact of project operation is also expected to be minimal. Water quality in Killian Creek will be affected in two ways: stream flow will be reduced due to the withdrawal of water for project use and stream chemistry will be affected due to project wastewater discharges. Stream flow reduction will be minimized by use of a water storage pond and by limiting withdrawals to periods of ample stream flow. Wastewater discharges to Killian Creek will meet the requirements of the National Pollutant Discharge Elimination System (NPDES) permit. He further testified that effects of operation on aquatic macroinvertebrates and fish will be minimized by the use of the water storage pond and by the low withdrawal velocities at the Killian Creek intake structure. Projected sound contours during operation of the plant were developed from manufacturer's specifications to estimate sound levels at various distances from the plant. It is expected that the sound will not adversely impact the surrounding community. Witness Priory also testified that detailed evaluations of the air quality impacts had been performed in support of the air quality Prevention of Significant Deterioration (PDS) permit and that modeled concentrations are well below ambient air quality standards. He testified that emissions will meet the requirements of the permit and will have minimal impact on existing air quality.

Witness Crawford-Brown questioned the reliability of sulfur dioxide measurements obtained at the Iron Station monitor as a basis for estimating the sulfur dioxide ambient level at the Lincoln Combustion Turbine Station site. He testified that a monitor closer to the Lincoln Combustion Turbine Station might show a larger effect from emissions at Duke's existing plant and might cause standards to be exceeded. Witness Crawford-Brown also testified about concerns with air quality under expected changes required by the new Clean Air Act. The Lincoln County site is in a panhandle of land surrounded on three sides by areas of concern with air quality. Witness Crawford-Brown testified that the new Clean Air Act may result in new monitoring in the Charlotte area which may place that area in the "serious" air quality category. Such a category would require reduction in sulfur dioxide emissions and may result in closer scrutiny of new sulfur dioxide and nitrogen oxide emissions in the surrounding area. He conceded that reductions might be accomplished through the anticipated system of allotments, and on cross examination he conceded that the manner in which the Clean Air Act will be administered in North Carolina has not been established yet.

Duke witness Priory explained that the purpose of using data from the Iron Station monitor in the modeling was to capture the ambient air quality absent any sources. All existing sources were then modeled in the analysis. This results in emissions from Marshall, Allen, and Riverbend being modeled into the study. In fact, to the extent that emissions from Marshall, Allen, and Riverbend are already included in the ambient air quality at Iron Station, there is some double counting of these emissions.

Various public witnesses also testified concerning the site. The proposed site is now in a quiet, rural area. Construction and operation of the proposed plant will cause a substantial increase in noise and traffic. Witnesses expressed particular concern about traffic since fuel oil will be delivered by tanker truck on a narrow, two-lane, winding rural road. The same road carries school buses for the three nearby public schools. Various witnesses testified to the deterioration of the quality of life in the area and to the loss of other, more desirable development in the area.

The Commission concludes that Duke has carried its burden of proof as to the appropriateness of the site of this facility. Duke has located a site which is less than a mile from a gas transmission line, has an adequate existing transmission line, and has an adequate water supply. Duke did not displace any homeowners in obtaining this site, and the site has substantial acreage so as to provide a large buffer area separating the plant from adjacent property owners. The Commission is mindful of the concerns addressed by the Intervenors and by the public witnesses. The traffic concerns expressed were largely premised on the facility's running 24 hours a day with no oil in the storage tanks, a scenario which is highly unlikely. The Commission is also cognizant of the public witnesses' testimony on the history of the site, which once included the home where Stonewall Jackson was married. This home was torn down prior to Duke's purchase of the property, and Duke has conducted comprehensive studies of the site to ensure that there are no significant historical or archaeological sites. The Commission also notes that the site is adjacent to an active quarry. Construction and operation of the facility will undoubtedly have some effects on the surrounding area; however, this is inevitable wherever the facility is located. Primarily, concerns as to water and air quality are the responsibility of other agencies, and the Commission will condition the certificate granted herein upon Duke's compliance with applicable environmental permits. The effect that compliance with environmental permits will have on the cost of locating the facility at this specific site is considered hereinafter. Subject to that discussion, the Commission concludes that the proposed site of the Lincoln Combustion Turbine Station is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding is contained in the testimony of Duke's witnesses Priory and Denton, Public Staff witness Nightingale and Intervenors' witness Crawford-Brown.

Witness Priory testified concerning the cost of the Lincoln Combustion Turbine Station. He testified that the Lincoln facility will include 16 General Electric simple cycle combustion turbine units, each rated at 72.8 mW, and auxiliary equipment. Total plant capacity will be 1,165 mW. The facility will tie into an existing 230 KV transmission line on the plant site. The facility will also include two 5-million gallon fuel oil storage tanks, administrative and maintenance support buildings, and a water storage pond. The units will be fueled by either natural gas or fuel oil. A natural gas pipeline is located less than one mile from the station. The project cost estimate is dependent on the schedule for bringing the units in service. Duke Exhibit RBP-1 indicated plans to install from four to twelve units in 1994, with the remainder in 1995 and 1996, and in-service cost from $480.523,000 to $517,560,000. The estimate includes all required labor, materials, equipment, contingency, and engineering and supervision costs, as well as overhead costs and legal expenses. In discussing the current project schedule, Mr. Priory identified a construction start date of October, 1991, with the first six units in service by summer of 1994. The remaining ten units are scheduled to be in service by summer of 1995. He indicated that the current schedule is based on the capacity requirements outlined in Mr. Donald H. Denton's testimony. Witness Denton stated that Duke plans to build the plant in the most cost efficient manner to meet the needs of the system, taking into account all of the parameters that impact construction. Other evidence tended to show that two-thirds of the estimated costs are under contract and one-third is not.

The primary concerns raised with respect to the cost of the facility are those concerning the air and water permitting costs. By filing dated November 19, 1990, the Attorney General urges the Commission to delay its decision in this case until such time as a reasonable showing of the costs and conditions of compliance with air and water quality environmental regulations could be made.

N.C.G.S. 62-110.1 requires an applicant to file "an estimate of construction costs in such detail as the Commission may require." The Commission must approve the cost estimate. Rule R8-61(b)(9) requires an applicant to provide the following:

> A statement of estimated cost information, including plans and related transmission capital costs . . . ; all operating expenses by categories, including fuel costs and total generating cost per net KWH at plant; and information concerning capacity factor, heat rate, and plant service life.

Cost estimates, not actual cost figures, are required by the statute and the regulation and Duke has provided the cost information required. Duke witness Priory testified that the cost estimate is reasonable. The Commission recognizes that any cost estimate may change over time for a variety of reasons, including the permitting and licensing process.

The siting and construction of a generating facility involves numerous permits and licenses as shown on pages 8-1 to 8-3 of Duke's Rule R8-61(b) filing. The permitting and licensing process is time consuming and costly. Duke has spent approximately $8,775,000 on the Lincoln Combustion Turbine Station site and plans to spend an additional $16,141,000 prior to the start of construction in October 1991. The ultimate cost of compliance with environmental permits at this site is not known and cannot be known at the present time. In this case uncertainty is greater than usual because of the recent passage of new legislation on air quality. The February 27, 1991, letter from DEM which the Attorney General has asked to submit as an exhibit does not either resolve Duke's pending air permit applications or quantify new costs resulting from the Clean Air Act. We deny the Attorney General's motion to submit the letter as evidence.

The Commission concludes that it cannot withhold a decision indefinitely, as requested by the Attorney General, since G.S. 62-82 directs the Commission to decide certificate applications within a certain time frame. Based on the estimate and the testimony now available, the Commission finds that Duke's cost estimate is reasonable. However, we recognize that the actual cost is dependent upon future regulatory developments, the actual construction schedule and other factors. The Commission will therefore direct further reporting and opportunity for reevaluation as hereinafter provided.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

This finding, which is really a conclusion of law, is based upon the preceding findings and discussions of evidence.

Duke asks the Commission to issue a certificate of public convenience and necessity. Duke recognizes that it must construct and operate the facility in strict accordance with all applicable laws and regulations, including permits to be obtained from the Division of Environmental Management and the Division of Water Resources dealing with air and water quality. Duke also recognizes that it must provide progress reports as required by G.S. 62-110.1(f), as well as the various filings required by the Commission rules on least cost integrated resource planning.

The Public Staff asks the Commission to go further. In addition to incorporating the Public Staff's agreement with Duke on DSM and NUG issues, which has already been discussed, the Public Staff wants the Commission to require Duke to address specifically, and separately from other plants, the proposed schedule and continuing need for the Lincoln Combustion Turbine Station in connection with future least cost integrated resource planning filings. The Public Staff also wants a status report addressing the status of engineering, outstanding permits, changes in costs, and the reasons for any changes in costs. The Public Staff sees these filings as a means of providing an opportunity to reevaluate this proposed facility based on future changes in need or costs. It maintained that future reevaluations of the project in LCIRP filings are advisable because Duke can cancel or postpone some of the planned units as conditions require.

As noted above, the Attorney General asks the Commission to continue this proceeding until more evidence is available on the cost of complying with environmental regulations. CUCA asks the Commission to issue a certificate "on a tentative basis" and to revisit the need for the facility annually. Finally, Intervenors urge the Commission to deny a certificate, arguing that Duke has failed to carry its burden of proof.

Previously in this Order, the Commission has found and concluded that there is a need for the generation represented by this facility, that the facility is consistent with Duke's current least cost integrated resource plan, that the proposed site is appropriate, and that the present cost estimate is reasonable. The Commission concludes that a certificate of public convenience and necessity should be issued. However, as noted above, the Commission recognizes the uncertainties in the load forecasts and the time of commercial operation for the individual units of the Lincoln Combustion Turbine Station. Further, the Commission notes that the pollution control technology for the facility and the cost of complying with environmental regulations cannot be known at this time. We are not dealing with the usual uncertainties of construction. The recent passage of new clean air legislation, the full effects of which will not be known for some time, makes the situation unique. The Commission concludes that it is best to proceed by issuing a certificate based on the present evidence and within the time frame required by G.S. § 62-82, but to require the special reports, in addition to those otherwise required by statute, as suggested by the Public Staff.

More specifically, the Commission is of the opinion that Duke should file periodic status reports for the Lincoln Combustion Turbine station showing: (1) the status of necessary State and Federal permits; (2) the status of engineering and construction; (3) explanations for any significant changes in costs or cost estimates; and (4) explanations for any significant changes in forecasts or need for the project. The status reports should be filed annually as a part of the annual short-term action plans filed pursuant to Commission Rule R8-59, and they should be subject to updates under essentially the same circumstances as updates to the short-term action plans. For example, Commission Rule R8-60 requires that an update to the short-term action plan be filed within 30 days after any significant change in the load forecast. Such an update should also be filed within 30 days after any significant change in costs or cost estimates. The Lincoln Combustion Turbine station should be discussed separately from the other combustion turbines in Duke's short-term action plans.

The current docket number for filing short-term action plans is Docket No. E-100, Sub 58. If future generic LCIRP proceedings are held in a different docket rather than E-100, Sub 58, subsequent short-term action plans will be filed in that different docket rather than in E-100, Sub 58.

The Commission also concludes that Duke should file a status report approximately six months in the future describing the status of necessary permits from state agencies, including the Division of Environmental Management (DEM), and also describing the cost impact and other impacts of the Federal Clean Air Act on the Lincoln Combustion Turbine Station to the extent that such impacts can be more clearly determined at that time. In this context, such impacts should also include other generating plants affected by measures taken to add the Lincoln Combustion Turbine Station to the Duke system.

Finally, the Commission must turn to the recent motions dealing with the proposed intervention of Empire Power Company. The Commission issued an Order on February 20, 1991, denying Empire's Petition to Intervene. That Order was based on the Petition having been filed too late. The Commission has been asked to reconsider, and we have done so. We reaffirm the denial of intervention in this docket. As noted above, the procedure for certificate applications is specified by G.S. § 62-82. The Commission does note, however, that Empire has also petitioned to intervene in Docket No. E-100, Sub 58, and a separate order has been issued in that docket.

IT IS, THEREFORE, ORDERED as follows:

1. That a Certificate of Public Convenience and Necessity is hereby granted to Duke Power Company for the construction of the Lincoln Combustion Turbine Station, having an output of 1,165 megawatts, to be located on a site near Lowesville in Lincoln County, North Carolina, as applied for in this proceeding subject to the conditions hereinafter set forth.

2. The plant will be constructed and operated in strict accordance with all applicable laws and regulations, including permits issued by the North Carolina Department of Environment, Health and Natural Resources, and with the current requirements imposed by the Division of Water Resources as set forth in AG-Duke Exhibit No. 4 with such changes as Duke and the Division of Water Resources may agree to hereafter.

3. That Duke Power Company shall file status reports with the Commission at least annually containing the following information about the Lincoln Combustion Turbine Station project:

(a) the status of necessary State and Federal permits;
(b) the status of engineering and construction;
(c) explanations for any significant changes in costs or cost estimates; and
(d) explanations for any significant changes in forecasts or need for the project.

4. That Duke Power Company shall file the status reports required herein as part of its annual short-term action plans submitted pursuant to NCUC Rule R8-59. Such reports and plans shall be filed in Docket No. E-100, Sub 58, until such time as the Commission opens a new generic docket on least cost integrated resource planning.

5. That Duke Power Company shall file updates to the status reports required herein within 30 days after any significant change in the cost estimates or forecasted need for the project, and that said updates shall be filed as updates to the current short-term action plans.

6. That the status reports required herein shall discuss the LCT project separately from the other combustion turbines in Duke's short-term action plans.

7. That Duke Power Company shall file a supplemental report with the Commission approximately six months after the date of this Order describing the status of necessary permits from state agencies, including the Division of Environmental Management, and also decribing the cost impact and other impacts of the federal Clean Air Act on the Lincoln project. The supplemental report shall also describe said impacts on other generating plants resulting from measures being taken to add the Lincoln project to the Duke system.

8. That the agreement between Duke Power Company and the Public Staff regarding DSM and NUG programs as discussed herein is hereby approved and adopted.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of March 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

DOCKET NO. EC-51(T), SUB 5

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Solomon Horney, Route 2, Box 31, Banner Elk, North Carolina 28604, Complainant, v. Mountain Electric Cooperative, Inc. P.O. Drawer 180, Mountain City, Tennessee 37683, Respondent,	ORDER DENYING COMPLAINT AND REAFFIRMING ORDER OF JULY 31, 1990

HEARD IN: The Commission Hearing Room, Room 2115, Dobbs Building, 430 North North Salisbury Street, Raleigh, North Carolina on October 18, 1990

BEFORE: Commissioner Sarah Lindsay Tate, presiding, and Commissioners Julius A. Wright and Laurence A. Cobb.

APPEARANCES:

For the Complainant:

Mr. Lloyd Hise, Jr., P.A., Post Office Box 743, Spruce Pine, North Carolina 28777

For the Respondent:

Mr. Robert F. Page and Mr. Robert B. Schwentker, Crisp, Davis, Schwentker, Page & Currin, Post Office Drawer 30489, Raleigh, North Carolina 27622

For the Intervenor:

Mr. Thomas K. Austin, North Carolina Electric Membership Corporation Post Office Box 27306, Raleigh, North Carolina 27611

For the Using and Consuming Public:

Mr. A. W. Turner, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: This matter was instituted on February 16, 1990, with the filing of a letter, treated by the Commission as a Complaint, by Mr. Solomon Horney against Mountain Electric Cooperative, Inc. ("MEC"). On February 22, 1990, the Commission issued an Order serving the Complaint of Mr. Horney ("Horney" or the "Complainant") on MEC. An Intervention and Motion to Dismiss for lack of jurisdiction was filed on February 28, 1990, by the North Carolina Electric Membership Corporation ("NCEMC"). On March 16, 1990, MEC filed a Motion to Dismiss and Answer asserting that the Complaint failed to state a cause of action. By Order issued on April 5, 1990, the Commission granted the Motion to Intervene filed by NCEMC and scheduled oral argument on the pending Motions to Dismiss.

At the request of counsel for NCEMC, the oral argument originally scheduled for May 2, 1990, was rescheduled to May 9. Such oral argument was subsequently rescheduled and heard on May 16, 1990, by the full Commission. Following the oral argument, by Order issued on July 31, 1990, the Commission denied the Motions to Dismiss; scheduled hearings in this matter for the date, time and place listed above; directed that discovery in this matter be completed by September 14, 1990; required testimony on behalf of Mr. Horney, and any party supporting him, to be filed on or before September 24, 1990; and, finally, required that testimony on behalf of MEC, and any party supporting it, be filed on or before October 9, 1990. Prefiled testimony, as directed by the Commission, was filed by Mr. Horney on September 27, 1990, and by MEC on October 9, 1990.

On October 10, 1990, special counsel for MEC filed a Notice of Appearance and Motion to Strike certain portions of the prefiled testimony of Mr. Horney and a Motion to Expedite this proceeding. By Order of October 17, 1990, the Commission noted, for the record, the appearance of special counsel for MEC and deferred ruling on the Motions to Strike and Expedite until the hearing of this matter. At the hearing, the Commission, with consent of all parties, took judicial notice of the "Ridge Law" (G.S. 113A-205, et seq.) and, thereupon, granted the pending Motion to Strike. The Complainant presented the testimony and exhibits of Solomon Horney. MEC offered the testimony and exhibits of Joseph A. Thacker, III, and Robert E. Mashburn, II. At the conclusion of hearings, the Commission received into evidence all of the prefiled testimony, summaries of testimony, and cross-examination, as well as the various exhibits offered by the parties. Thereupon, the record of evidence in this matter was closed. The Commission offered the parties an opportunity to file proposed Orders and briefs, which were subsequently filed on or about November 26, 1990.

Based upon the foregoing, the testimony and exhibits received in evidence at the hearings, and the Commission's entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. The Complainant, Solomon Horney, is a citizen of North Carolina, residing at Route 2, Box 31, Banner Elk, North Carolina, in a community known as "Horney Hollow," alongside N.C.S.R. 1328 (the "Edgar Tufts Road").

2. The Respondent, Mountain Electric Cooperative, Inc. ("MEC"), is a nonprofit, rural electric membership cooperative, which owns and operates an electric transmission and distribution system in northwest North Carolina and northeast Tennessee. MEC was organized and incorporated in the State of Tennessee in March 1941 and was subsequently licensed to operate in North Carolina as a foreign corporation. MEC's headquarters are located in Mountain City, Tennessee, and it has a district office in Newland, North Carolina. MEC presently serves approximately 13,300 retail electric customers in North Carolina, and its service territory covers portions of Avery, Burke, McDowell and Watauga Counties in northwest North Carolina.

3. NCEMC is an electric membership corporation organized and operating under Chapter 117 of the General Statutes of North Carolina. NCEMC is a generation and transmission cooperative, sited both corporately and physically within the State of North Carolina, and, as such, is authorized by law to build and operate generating and transmission facilities within the State.

4. The Public Staff - North Carolina Utilities Commission is an agency created pursuant to G.S. 62-15. The Public Staff is charged with the duty and responsibility of representing the interests of the "using and consuming public."

5. MEC proposes to construct and operate a 69 KV transmission line for the purpose of bringing additional power and energy to the Town of Beech Mountain, North Carolina, and surrounding areas, and to relieve existing overload conditions on its existing 13 KV distribution line serving the Beech Mountain area and its existing Banner Elk Substation.

6. The proposed transmission line and related facilities, including a "tap lot" adjoining MEC's existing 69 KV Cranberry-Banner Elk transmission line, will run up to the top of Beech Mountain, terminating in a substation to be constructed on a lot near the load center. The proposed line does not require a Certificate of Public Convenience and Necessity. Nonetheless, the Commission finds that the new transmission and substation facilities are urgently needed in order to serve present and anticipated future loads in and around Beech Mountain.

7. The concept for the proposed transmission line originated with the Tennessee Valley Authority ("TVA"), which then owned all of the transmission lines in MEC's service territory, in the late 1970s. It was subsequently included in MEC's 20-Year Work Plan prepared by MEC's consulting engineers, Allen & Hoshall, in November 1982. The project was then included in MEC's 1984-1985 Two-Year Construction Plan, also prepared by Allen & Hoshall. The actual route selection process began in January 1985, and it took until May 1987 to select the presently proposed route. Next, the project was included as a critical item in the Power Supply System Long Range Plan prepared by Allen & Hoshall in March 1988. Finally, the project was also included, as a carryover, in MEC's latest Two-Year Construction Work Plan.

8. MEC has acquired, through purchase, negotiation, verbal approval, or condemnation, approximately 93% of the land rights of way ("ROW") required for the project. MEC's presently proposed corridor route location would require an easement over a 0.11 acre portion of Mr. Horney's property. No actual physical facility will be located on Mr. Horney's land; the only direct impact on Mr. Horney will be an aerial cable running over a narrow stretch of a creek, Lee Branch, which forms the boundary line between Mr. Horney's property and the adjoining property belonging to the Mary Maxcy Estate.

9. MEC acted reasonably and responsibly in its selection of a "tap-on" or "tap lot" site as an originating point to begin the new transmission line from a junction with existing transmission facilities.

10. MEC was reasonable and responsible in its selection of a terminating point for the new transmission line, a substation to be located at the top of Beech Mountain, near the anticipated load center.

11. MEC has been reasonable and responsible in its selection and negotiation of a corridor route to connect the "tap lot" with the new proposed substation to be located on the top of Beech Mountain.

12. MEC has consulted and cooperated with Mr. Horney in attempting to minimize the relative damage to be imposed by the new transmission facility on Mr. Horney's property, as well as the adjoining property of the Mary Maxcy Estate. MEC's flexibility in negotiating with Mr. Horney has been minimized due to the proximate location of the Horney property to the preferred "tap lot."

13. MEC has followed reasonable and prudent standards for the design of transmission facilities and the selection of an appropriate corridor route.

14. MEC has given proper consideration to relevant environmental factors.

15. Horney Alternate I is not preferable to the corridor route selected by MEC.

16. Horney Alternate II is not preferable to the corridor route selected by MEC.

17. Mr. Horney's proposal to move the entire burden of the transmission line corridor off of his property and entirely onto property belonging to the Mary Maxcy Estate is not reasonable under all of the existing circumstances.

18. MEC's proposed transmission project is currently needed to relieve overload conditions both on MEC's existing 13 KV distribution lines and its Banner Elk substation. Construction of this facility is already far behind schedule. Reliability of service in and around Beech Mountain and Banner Elk is threatened for the winter of 1991-1992. The project should be completed without further delay.

19. From an engineering, operational, safety and environmental point of view, MEC's decision to construct its new transmission line along the corridor route selected by MEC was a reasonable one.

20. The Commission reaffirms its Order of July 31, 1990, deciding that the Commission has jurisdiction to hear this complaint.

21. The Commission has no jurisdiction to consider the issue, raised by Mr. Horney in his brief, that MEC has no authority to condemn Mr. Horney's property.

CONCLUSIONS OF LAW

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-5

The evidence for these Findings of Fact is contained in the original Complaint and testimony of Mr. Horney, the Motion to Dismiss filed by NCEMC, the Answer and Motion to Dismiss, as well as the testimony of Mr. Joseph A. Thacker, III, of MEC, and N.C.G.S. 62-15. These Findings are essentially procedural and jurisdictional in nature, and were not contested by any party.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this Finding is contained in the testimony of MEC witnesses Thacker and Mashburn. According to Mr. Thacker, the proposed transmission line will tap onto MEC's existing Cranberry-Banner Elk 69 KV line in the general area of Banner Elk. The proposed "tap lot" is located on the southwest corner of the intersection of S.R. 1328 and S.R. 1528. From there, the proposed transmission line will extend 2.2 miles in a northeasterly direction to the site of a proposed substation located on Beech Mountain behind the Town of Beech Mountain equipment storage area. The new line will be 69 KV, phase to phase, consisting of direct embedded, weathering steel, single-pole structures. The poles will have polymer horizontal post insulators and the structures will carry four wires consisting of three 556.4 ACSR conductors and one 3/8" high-strength steel wire as an overhead static. The proposed transmission line will require a 50' right-of-way ("ROW") easement and is estimated to cost between $1,350,000 and $1,600,000, including construction and easement costs, but not including legal expenses.

The transmission line is necessary in order to relieve overloaded conditions on MEC's existing 13KV distribution line serving Beech Mountain and MEC's Banner Elk Substation. The present power requirement on Beech Mountain is roughly 22 MW and a continued high growth rate is expected for the future. Also, as noted in the testimony of MEC consulting engineer witness Mashburn, the design load level of MEC's present 13 KV circuits has been reached and surpassed during previous years. The circuits are now operating in an overloaded mode, which creates voltage problems, excessive line losses, and greatly extends the time required to restore service after an outage. Mechanical damage to the conductor, splices and other terminating hardware is possible. The proposed 69 KV transmission line and new Beech Mountain substation will provide adequate power for about 50 MW of load to be distributed on four to six 13 KV circuits proposed for the area.

No party to this proceeding contended that the new transmission line and substation were not needed to provide adequate power supplies in and around the Beech Mountain - Banner Elk area. While the Commission is not required to issue a certificate of public convenience and necessity for a transmission line project such as the one proposed by MEC, the Commission nonetheless finds and concludes, based upon the uncontradicted evidence of record, that there presently exists an urgent need and demand for the additional electric power and energy which MEC proposes to bring to the top of Beech Mountain through the proposed 69 KV transmission line project.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this Finding of Fact comes from the testimony of MEC witnesses Thacker and Mashburn. This Finding was essentially uncontroverted and, just as with the demonstrated need for the transmission line project (Finding of Fact No. 6, above), the Commission concludes that construction of additional transmission facilities to bring more power to the load center at the top of Beech Mountain has been a continuous part of MEC's planning process for the last eight years. The project has taken on additional urgency as the load being served by the existing MEC 13 KV distribution facility has grown.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this Finding of Fact appears in the testimonies of Complainant Horney and Respondent witness Thacker. As stated by MEC witness Thacker, MEC already has signed or oral agreements with 81% of the required ROW easements for the entire length of the new transmission line. Another 12% of the required ROW have had damages assessed by commissioners during the condemnation process and may be acquired by MEC at any time. In addition, the two easements adjoining the Horney property have already been acquired. Mr. Thacker further noted that the center line of the proposed transmission facility crosses only 38 feet of Mr. Horney's southeast corner. The full fifty-foot width of the easement does not occur on Mr. Horney's property since the center line lies so close to the eastern edge of his property, which is the center line of Lee Creek. The total area involved in the easement sought by MEC is only 0.11 acre. Except for certain minimal tree and brush clearing, MEC will not actually have to conduct any construction, nor locate any physical facilities (other than the aerial wire itself) on Mr. Horney's property.

Mr. Horney appeared to be of the opinion that the MEC proposal would "take" most of his side yard, including the area which is presently being used for his septic tank and drain field. It is, however, apparent from the specific MEC proposal that the construction contemplated by MEC would not require Mr. Horney to move his septic tank or drain field. None of the poles or guy wires required for the project will be located on Mr. Horney's property. Instead, the poles will be located to the south and north of Mr. Horney's property. In routing the proposed aerial wire down the center of Lee Creek, MEC has tried to minimize the burden of the new line on both Mr. Horney and the adjacent Mary Maxcy Estate. Unquestionably, there will be some visual impact and other damage to Mr. Horney's property values. These are the proper subject for negotiation or a condemnation action. Mr. Horney will not, however, be forcefully evicted from the use and enjoyment of his home.

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

In designing a transmission facility such as the one proposed by MEC, two points are critical. The first (Point A) is where the line originates by tapping onto an existing transmission facility. The second (Point B) is where the transmission line terminates in a substation. Based upon the evidence presented, the Commission concludes that MEC's selection of both Point A (the "tap lot" or originating point) and Point B (the substation site at the top of Beech Mountain) were reasonable choices under all the prevailing circumstances. .

With regard to Point A (the "tap lot"), Mr. Thacker testified that the existing project plans specified a three-way pole mounted switch to be installed on a tap-off pole. This pole and switch must be located so as to be readily accessible to MEC personnel in the event of an emergency. Mr. Mashburn's testimony was consistent with and supported Mr. Thacker's testimony on the location of Point A. Although MEC first considered a "tap off" location adjacent to the existing Banner Elk substation, that location appeared to be undesirable due to lack of ready accessibility and extensive modifications that would be required to accommodate the "tap lot".

When the Banner Elk location appeared to be less than desirable, other locations were determined by following the existing Cranberry-Banner Elk transmission line back toward Cranberry until it crossed an accessible location. The first readily accessible location going back along the existing transmission line, away from the Banner Elk Substation, is where the Cranberry line crosses S.R. 1328, in the vicinity of Mr. Horney's property. The existing transmission span at the S.R. 1328 crossing is sufficiently long that a single three-way switch and pole can be installed in-line with no alteration to the existing transmission line.

Mr. Horney's argument was not so much with the location of "Point A", but with the fact that, as a result of such location, the resulting transmission corridor route would cross a portion of his property. The Commission concludes, however, that MEC followed appropriate engineering and design criteria and was reasonable in its selection of a suitable "tap lot" site.

Mr. Thacker also described the lengthy process which MEC had undertaken to locate a suitable site for the new proposed Beech Mountain Substation Point B. The most desirable location for the substation would be as near as practical to the load center, which is the snow-making equipment at the Beech Mountain Ski Resort. Mr. Thacker also noted, however, that other concerns, such as environmental and public considerations, availability of usable land, and access for the incoming transmission line, also had a significant impact on site selection for the Beech Mountain Substation.

A small vacant parcel of land adjacent to the snow-making equipment was investigated in 1985. This site, referred to as the "Salt Bin Site," was determined to be too small. Another site was considered in 1986. After lengthy and extensive negotiations, an adjacent land owner refused to waive his rights to the sixty-foot access road easement and, in early 1989, this site was also abandoned.

In mid-1989, the currently proposed substation site was selected. The site is somewhat further from the load center than the two prior selections, but is adequate. Mr. Horney raised little objection to the location of the proposed new Beech Mountain Substation site. Just as with Point A, his concern seemed to be that the selection of Points A and B by MEC virtually dictated that MEC would be required, at the least, to cross portions of his property with aerial transmission cable.

Based upon the foregoing, the Commission concludes that MEC applied proper engineering and design criteria to the selection of a proposed substation site and that the factors which required movement of the proposed substation site from the original site, to the 1986-1989 secondary site, to the site ultimately selected and acquired were factors of engineering design or other factors over which MEC largely had no control.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-14

The evidence for these Findings of Fact is contained in the testimony of Complainant Horney and the testimony and exhibits of Respondent witnesses Thacker and Mashburn. Although Mr. Horney was unhappy that the ultimate corridor location selected by MEC did cross a portion of his property, he conceded that he had no professional background or training in electric engineering and that he had never designed any electric lines.

Mr. Thacker described the route selection process followed by MEC. The first step was determining the starting and ending points (Point A and Point B). Once these were selected, aerial photography maps, U.S.G.S. 7.5 Minute Quadrangle maps and tax maps were examined, residential and development areas were located, and field surveys conducted to determine possible corridors. Environmental impacts were a major concern due to the scenic nature of the general area and increasing public awareness of aesthetics and preservation of the environment. In order to comply with the design and corridor criteria used by MEC, the Point A - Point B corridor needed: (1) to minimize conflict with present and planned uses of land; (2) to conceal poles and lines as much as practical; (3) to avoid routes along ridges and avoid crossing hills or high points at crest; and (4) to utilize existing roads for construction and maintenance as much as possible. To make the line as attractive and unobtrusive as possible, MEC decided to use a Narrow Profile Lines Structure design. The transmission line design consists of weathering steel, single-pole structures that are direct embedded.

Mr. Mashburn also recited a series of transmission line design criteria employed by MEC in this project. One such design criteria was the cost of the facility, including both initial cost and total life cycle cost. Also, the transmission line facility should have a very high level of reliability of operation. MEC tries to locate a transmission line generally along property lines, rather than bisect or go through the middle of property, whether developed or undeveloped. MEC attempts to keep its costs down so that consumers' rates can be kept as low as possible. MEC also tries to keep a line as direct as possible in order to ease the resulting design construction requirements. MEC weighs and evaluates several environmental factors and constraints and, in that regard, is required to have its plans approved by TVA and REA. Mr. Mashburn testified that, during MEC's site selection and route evaluation process, it had performed two environmental reports, termed Borrower's Environmental Reports, that were filed with the appropriate state agencies.

One of the arguments asserted by Mr. Horney, in his original Complaint and through questioning by his counsel of the MEC witnesses, was that, while MEC has cooperated with other land owners and developers in moving the proposed corridor route so as to avoid developments where there were no, or very few, existing dwellings, MEC had not been equally responsive to his concerns in moving the proposed corridor route further away from his home.

MEC presented several responses to Mr. Horney's assertions. Some of these matters will be dealt with in more detail hereafter in the Evidence and Conclusions for Finding of Fact No. 17. First, as noted by MEC witness Thacker, MEC did conduct negotiations with Mr. Horney and, as a result of his objections, moved the location of a pole that was originally designed to be set in Mr. Horney's yard. This pole was moved across the road onto property already belonging to MEC.

A second response by MEC to Mr. Horney's contention was that it was attempting to "equalize the burden" between Mr. Horney's property and the adjoining property of the Mary Maxcy Estate. As shown by MEC (Thacker) Exhibit

C, the relative impact of the proposed transmission line corridor is considerably greater on the Maxcy Estate than on Mr. Horney's property. As stated by Mr. Thacker, "considering both properties together and trying to minimize the burden on any given piece of property, the best place to run the line is down the creek bed, which is what MEC has proposed." Mr. Thacker noted that, in these circumstances, MEC felt it necessary to look at both properties together and, in locating the proposed transmission line, tried to accommodate and give consideration to both the Horney property and the Maxcy Estate property.

MEC also pointed out that, in many respects, it was the unique location and size of Mr. Horney's property which restricted MEC's flexibility in attempting to negotiate a corridor route with Mr. Horney. As noted by Mr. Mashburn, Mr. Horney's property is located in very close proximity to the starting point (Point A) of the facility. This location imposes limitations on the types of accommodations which MEC is able to make for Mr. Horney.

For the foregoing reasons, the Commission concludes that MEC has acted reasonably and responsibly in selecting a corridor route to connect Point A (the "tap lot") with Point B (the new Beech Mountain substation). MEC has followed reasonable and prudent standards for the design and installation of transmission facilities and has given proper consideration to relevant environmental factors. Finally, to the extent that it has been able to do so, given the location of Mr. Horney's property, which is directly across the road from the "tap lot", MEC has cooperated with Mr. Horney in attempting to minimize the damage to Mr. Horney's property while, at the same time, trying to balance the relative damage to Mr. Horney's property versus the damage to the adjoining Maxcy Estate property.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 15

As a portion of his presentation, Mr. Horney proposed that MEC be required to use an alternate corridor route, referred to as Horney Alternate I, for its proposed transmission line. Horney Alternate I would leave the existing 69 KV Cranberry-Banner Elk transmission line approximately 1,000 feet northwest of the existing Banner Elk substation, at the point where the existing transmission line makes an angle turn west toward Cranberry. From that point, Horney Alternate I proceeds in a northerly direction approximately 1,500 feet to a point where it crosses S.R. 1328, approximately .6 mile north of Mr. Horney's home. From S.R. 1328, Horney Alternate I runs northeasterly, and east of the line proposed by MEC, up Beech Mountain to the location of the proposed new sub-station. Mr. Horney advanced several reasons or advantages for the corridor proposed in Horney Alternate I: (1) it is substantially shorter; (2) for approximately 3,000 feet, it would pass over open fields and would require very little timber cutting; (3) it would not pass near any homes or residences; (4) it is not as steep; (5) it is closer to, although not within, existing developed areas and would not disturb as much undeveloped property; and (6) it would have less of an impact on the scenic beauty of Beech Mountain.

Both of the MEC witnesses testified, in substance, that Horney Alternate I was not preferable to the corridor location which MEC wished to use. In the opinion of both witnesses, Horney Alternate I suffered from several major disadvantages and, in their view, the "advantages" claimed by Mr. Horney did not exist.

With regard to the disadvantages, MEC witness Thacker testified that MEC has already evaluated portions of Horney Alternate I as a possible corridor route. According to Mr. Thacker, Horney Alternate I does not provide for an accessible "tap off" location at its intersection with the existing Cranberry-Banner Elk transmission line. Also, Horney Alternate I would pass directly over a residential dwelling located on the north side of, and adjacent to, S.R. 1328. In addition, Horney Alternate I passes directly through the Deer Creek Falls Development and also would be visible to the Highland, Banner Grande and Deer Creek Falls Developments. Mr. Mashburn noted the same deficiencies mentioned by Mr. Thacker in Horney Alternate I. He also stated that he was unable to see any of the other "advantages" referred to by Mr. Horney. Even if the Horney Alternate I route were shorter, as claimed by Mr. Horney, Mr. Mashburn would still not recommend the use of Horney Alternate I because it fails the accessibility criterion.

As noted by Mr. Thacker, MEC had considered a route very similar to the proposed Horney Alternate I and had even surveyed and profiled such a route in June 1985. MEC discovered many problems with this proposed corridor, not even taking into account the lack of reasonable access. Some of the other problems included the large number of properties affected and an excessive number of angle poles which would be required. The route crossed 17 property tracts and had 15 angles over the 2.3 miles distance. As noted by Mr. Thacker, the proposed route, as profiled, looked something like a zipper, zigzagging back and forth across the mountain. These angles and turns were necessary in order to avoid platted areas for development. According to MEC, the number of problems encountered in its preliminary study made it self-evident that a corridor route further west of the Horney Alternate I corridor was more desirable.

A substantial amount of the hearing time was consumed in debating the issue of whether, in the proper design of transmission lines, it was better to avoid existing houses and structures (by running the line through areas platted for development, but not built upon) or, alternatively, whether the preference should be to avoid platted areas, even if that resulted in some impact on existing structures. Mr. Thacker stated that, as a part of the corridor selection process, MEC generally tries to avoid going through subdivisions, whether any houses had been built in the subdivision or not. When a subdivision plat has been recorded, it shows a possibility or a probable intent that there will or may be subsequent development there. In response to cross-examination, Mr. Thacker stated that, while MEC designs transmission corridors to try to avoid platted developments, if possible, its overall policy is to try to minimize the impact of the transmission line corridor to everyone concerned, that is, everyone who is passed by the transmission line corridor. Although Mr. Thacker conceded that the route now preferred by MEC would have approximately as many line angles as the route (similar to Horney Alternate I) previously abandoned by MEC, he stated that the two were not really comparable. The angles in the MEC preferred route are smaller and do not require as many guy wires. The line preferred by MEC does not zigzag or "snake" all over the mountain; instead, it follows a roughly straight line, with a slight curve, when going along a road crossing the Hufty property. Other small angles are simply a result of terrain. By way of summary, Mr. Thacker testified that the decision to abandon the previously proposed corridor location (similar to Horney Alternate I) was due to a combination of factors, including: the number and size of line angles required; distance of the proposed corridor; number of properties and property owners affected; number of developments affected; visual impact; lack of reasonable access to a tap-off location and to substantial portions of the line, for maintenance and emergency purposes; and the overall cost of the line.

Mr. Marshburn's testimony supported that of Mr. Thacker regarding the reasons why MEC chose not to pursue the earlier corridor (similar to Horney Alternate I). These reasons include: many property parcels to deal with, several existing structures or buildings to avoid, and a few extensive development or subdivision projects that would adversely impact the project. In addition, the proposed starting point at Banner Elk substation had proved to be unsatisfactory. Mr. Marshburn also stated that, in designing transmission lines, he recommended the avoidance of existing platted or planned developments. He noted that MEC has no control over the rate or speed at which platted developments in fact come into being and are built out and, for that reasons, MEC generally tries to follow accepted property lines or boundaries, taking into account certain natural features, including roadways, accessibility and limiting factors of terrain.

Based upon the foregoing, the Commission is unable to conclude that MEC acted unreasonably in selecting its preferred transmission line corridor as opposed to that recommended in Horney Alternate I. Several factors, including cost, appear to favor the route preferred by MEC. MEC pointed out numerous disadvanatges to Horney Alternate I. Perhaps the greatest of these "disadvantages" is the lack of an accessible location from which to "tap on" to the existing Cranberry-Banner Elk transmission line. The Commission is, therefore, unable to conclude that Horney Alternate I is preferable to the corridor route selected by MEC. This being so, the Commission further cannot conclude that MEC has acted arbitrarily or capriciously in its preferred corridor route selection.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

As a second alternative corridor route location, hereafter referred to as Horney Alternate II, Mr. Horney proposed that MEC simply follow the route of the "present existing transmission line" running from the Banner Elk substation up to the Town of Beech Mountain. The existing line has been in its present location for at least 20 years. Mr. Horney stated that following the corridor route of the existing line had several advantages, as follows: (1) the right-of-way (ROW) has been acquired and maintained for many years and little or no additional ROW would be necessary; (2) the existing line passes through an area that is already developed and would not disturb undeveloped areas of Beech Mountain; (3) there would be almost no timber removal and little or no additional environmental damage to Beech Mountain; (4) using the existing route would preserve the natural beauty of the undisturbed portion of Beech Mountain; and (5) the route would comply with the goals and policies of North Carolina in protecting and preserving scenic natural resources.

In contrast, both of the MEC witnesses listed a substantial number of reasons why Horney Alternate II was unfeasible to be used as a corridor for the new transmission line. In his prefiled testimony, Mr. Thacker listed at least eight reasons why MEC preferred not to follow the corridor of the existing 13 KV electric line. These reasons are as follows: (1) the existing 13 KV line is a "distribution" line, not a "transmission" line; (2) using the corridor of the existing "distribution" line as the location for the new "transmission" line would involve excessive construction costs due to a variety of factors; (3) building along the existing line would require numerous service outages during construction periods; (4) due to the location of structures and buildings in and around the existing corridor, there would be inadequate clearance between such structures and the proposed 69 KV circuits; (5) the existing ROW is inadequate to accommodate the proposed 69 KV construction; (6) due to its location which, in many areas, crosses or parallels Beech Mountain Parkway, there would be an increased exposure to the vehicular traffic; (7) the existing corridor involves a substantially higher number of affected property owners; and (8) MEC would experience a loss of reliability due to the location of all of its facilities (both transmission and distribution) on one route. (If the transmission line follows MEC's preferred corridor, the existing distribution lines will serve as a "back up" to the new transmission line.) In his testimony, MEC witness Mashburn presented the same fundamental "disadvantages" to Horney Alternate II as described by witness Thacker. He also presented additional reasons why Horney Alternate II was impractical or unfeasible. These included: (I) the existing 13 KV distribution route is presently utilized by other utilities, such as telephone and CATV; (2) additional construction time would be required to work with "hot" or energized lines; (3) some existing structures or buildings would have to be moved or demolished; (4) as constructed, the new line would still be subject to relocation if the Beech Mountain Parkway were ever widened; and (5) the combined transmission-distribution corridor would be a less flexible system for MEC to operate.

For the reasons cited by the MEC witnesses, the Commission concludes that Horney Alternate II is simply not a feasible alternative corridor for MEC to pursue. It has numerous, substantial disadvantages when compared to the corridor location preferred by MEC. The Commission cannot conclude that MEC was unreasonable in rejecting the corridor route proposed in Horney Alternate II and, therefore, cannot conclude that MEC acted arbitrarily and capriciously in refusing to pursue this potential corridor location.

EVIDENCE AND CONCLUSION FOR FINDING OF FACT NO. 17

As a final alternative, referred to hereafter as Horney Alternate III, Mr. Horney proposed that the lower end of the transmission line corridor simply be moved an indefinite number of feet to the east, thereby removing it entirely from his property and placing it entirely within the boundaries of the property belonging to the Mary Maxcy Estate. The two MEC witnesses presented several reasons whereby, in their opinion, it would be neither fair nor appropriate to follow the corridor route location suggested in Horney Alternate III. These reasons included, among others, the following:

1. Among MEC's transmission corridor design criteria was a preference to try to use natural geographic boundaries and property lines as the center line of the proposed corridor route location. By following this criterion, MEC is able to "balance the burden" of the potential damage done by the new transmission line among adjacent property owners and avoid inflicting all of the damage on one of them.

2. In relative terms, the transmission line corridor as proposed by MEC will inflict substantially greater damage on the Mary Maxcy Estate property than on the Horney property. Moving the line further to the east would only exacerbate this situation. As noted in Mr. Thacker's testimony, the center line of MEC's proposed transmission corridor crosses only 38 feet of Mr. Horney's southeast corner. The full 50-foot width of the easement does not occur on his property since the center line lies so close to the eastern edge of his property (Lee Creek). The total area of the Horney easement is only 0.11 acre. Only six trees in excess of eight-inch diameter will have to be cleared along the Lee Branch slope on Mr. Horney's property. There will be no poles or structures, other than the aerial line itself, located anywhere on Mr. Horney's property. As illustrated by MEC (Thacker) Exhibits B and C, the relative easement proposed on the Maxcy Estate property is considerably greater than the easement proposed on Mr. Horney's property.

3. Due to design constraints, if the transmission line corridor is moved east, so as to avoid Mr. Horney's property entirely, it will be necessary to move the line all the way to the east of S.R. 1328.

4. Changing the location of the lower end of the transmission line corridor to the east side of S.R. 1328 would cause substantial additional damage to the Maxcy Estate property, as well as the Ellen Puckett property, and would impose a substantial additional cost on MEC. As Mr. Thacker stated, moving the line to the east side of S.R. 1328 would create at least one additional angle pole which would require an additional overhead guy pole and additional guy wires on the Ellen Puckett property. The existing easements which MEC has acquired on the Maxcy Estate property would be valueless to MEC. MEC would have to acquire additional ROW from the Maxcy Estate, probably through condemnation, and would have to underbuild its existing distribution line on the east side of S.R. 1328. The additional cost to MEC for acquiring further ROW on the east side of S.R. 1328, from the Maxcy Estate, would probably be at least $25,000. The value of the additional property that would be required from the Maxcy Estate would be substantially greater than the value of the easement which MEC seeks to acquire from Mr. Horney.

5. If the transmission line were routed from the proposed "tap lot" to the east side of S.R. 1328, as proposed by Horney Alternate III, the Maxcy Estate would be left with a relatively useless "island" on the west side of S.R. 1328. This would require MEC to acquire more ROW than it actually needed and would unfairly burden both MEC (and its members) and the Maxcy Estate.

6. Finally, and perhaps most importantly, there is little or no reason to believe, if Horney Alternate III were accepted and the line moved entirely off of Mr. Horney's property to accommodate him, that the relocated line would be viewed with any greater favor or approval by the Maxcy Estate owners than it is presently viewed by Mr. Horney. As succinctly noted by MEC witness Thacker, representatives of the Maxcy Estate have opinions concerning the proposed transmission line

which are similar to Mr. Horney's. They also do not want it on their property. To the Maxcy Estates representatives, all of their property is very valuable frontage. MEC was actually required to go through condemnation proceedings to acquire the easement rights that it now holds on the Maxcy property.

During the cross-examination of MEC witness Thacker, MEC was challenged with regard to its willingness to "negotiate" a change in the corridor route location. It was asserted that, whereas MEC was willing to negotiate and move its proposed corridor to accommodate a Ms. Hufty, whose property is much further up the mountain and away from the proposed "tap lot", MEC was unwilling so to negotiate with Mr. Horney. The response to Mr. Horney's assertion on this point is contained in several portions of the transcript. The MEC witnesses pointed out that their primary difficulty in "negotiating" with Mr. Horney was the proximate location of his property, directly across the road from the proposed "tap lot". Ms. Hufty's property is located approximately halfway between the "tap lot" and the proposed Beech Mountain substation. A second factor is that the proposed transmission line corridor only crosses a narrow corner of Mr. Horney's property for a very limited distance. On the other hand, approximately one-third of the entire length of the transmission line will be located on Ms. Hufty's property.

The evidence disclosed that when possible, in negotiating ROW agreements or easements, MEC's policy is to attempt to negotiate the required ROW on a basis which is reasonable to both MEC and the property owner. MEC will bring condemnation proceedings against the property only as a last resort. In dealing with Ms. Hufty, who proposes a large development on her property, and whose property the line will have to cross for one-third of its length, MEC attempted to negotiate a corridor route consistent with MEC's needs, but which also met the needs and desires of Ms. Hufty in developing her property. Thus, expensive and time-consuming litigation was avoided.

During the course of the somewhat lengthy negotiations to date between MEC and Ms. Hufty, the parties discussed several different potential corridor locations through Ms. Hufty's property. Some of these have been "above the road"; others, including the most recent proposal, have been "below the road". The "below the road" proposal is not only consistent with the original proposal made to Ms. Hufty by MEC, it appeared to be the "better" route from the standpoint of both cost, damage to property, and overall environmental and safety considerations.

While some engineering considerations might tend to favor a location "above the road" on the Hufty property, the Commission cannot conclude, based upon the evidence listed above, that MEC has been unreasonable, arbitrary or capricious in pursuing its negotiations for a ROW with Ms. Hufty.

Based upon the foregoing, the Commission concludes that MEC's proposed "balancing the harm" design criterion is reasonable as applied to the facts of this case.

Further, the Commission is unable to conclude that MEC, in evaluating ways and means to construct the transmission line so as to minimize the potential harm on all affected parties, has acted unreasonably or improperly, or arbitrarily or capriciously. As proposed by MEC, the impact of the transmission line corridor on Mr. Horney is minimal. Only 0.11 acre of Mr. Horney's property is affected. Of that area, Mr. Horney will not be precluded from continuing to use his property for a side yard and a septic tank drainage field. There will be no actual physical facilities (poles, guy wires, etc.) located anywhere on Mr. Horney's property. Instead, the aerial wire will cross his property, running basically down the middle of the Lee Creek, for a distance of some 38 feet. The alternative proposed by Mr. Horney will cause an increase in engineering and design problems, will be more expensive, and will impose, in comparison, an excessive and unreasonable burden on the Maxcy Estate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The primary evidence for this Finding of Fact is contained in the testimony of MEC witnesses Thacker and Mashburn. Each of them testified, on numerous occasions, concerning the critical need for this new transmission line to be constructed and energized. Mr. Horney testified that he did not challenge the need to bring additional power up to the top of Beech Mountain, as asserted by MEC.

Witnesses Thacker and Mashburn both testified concerning the critical need for this new transmission project. The existing 13 KV distribution circuit, which presently supplies all of the power to the Town of Beech Mountain and surrounding areas, is severely overloaded. The overload condition, which would be relieved by the construction of the proposed line, extends to the Banner Elk substation as well. The Beech Mountain Town Council is very concerned in seeing that the project is completed in a timely fashion and has expressed that concern many times. Several residents and consumers on the Mountain have acknowledged the need for the project. If the project is not completed in a timely fashion, brown-outs and black-outs are likely to occur during peak periods due to the overloaded condition. If there is a significant outage which lasts more than 30 minutes, the line protection devices that disconnected the line may be unable to quickly restore power due to cold load pickup. As a result, any outages which do occur could be longer than otherwise. If MEC is not allowed to build the proposed transmission line along its preferred corridor, additional delays and costs will result. MEC will essentially have to start again in terms of engineering planning and design. Some easements, already acquired, will have to be written off. Additional condemnation proceedings may be a likely result, with their attendant delay, if the corridor location is changed at this late date.

MEC witnesses testified that it is already too late to have the project constructed and energized in time for the 1990-1991 winter peak. They fear that if construction is delayed much longer, the project may very well not be energized in time for the 1991-1992 winter peak. In anticipation of being able to begin construction during 1990, MEC had previously ordered new substation and transformer equipment from manufacturers. Due to the delays which have already occurred in this project, MEC had to take that equipment and install it on another project in Tennessee.

Although the Commission sympathizes with Mr. Horney, understands his concerns, and appreciates his interest in not having any portion of this proposed transmission line project located on his individual residential lot, the Commission also has a duty and responsibility to protect the interests of other consumers located in and around the Town of Beech Mountain who need to have this project finally completed and energized. The record of evidence in this case is clear that the new 69 KV transmission line and substation project to bring additional power and energy to Beech Mountain, and relieve overload conditions at the Banner Elk substation, is critically needed. The Commission concludes that the project should be constructed and completed as rapidly as MEC is able to do so.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

Based upon the foregoing Findings of Fact, the Commission concludes that MEC's decision to locate its new transmission line corridor along the route selected by MEC was a reasonable and prudent exercise of judgment by MEC. This judgment took into account all of the appropriate factors, including public need, engineering, safety, protection of the environment, and avoidance of unnecessary damage to all of the properties located along the proposed transmission corridor.

As it has done in numerous prior cases, the Commission concludes that the "abuse of discretion" standard is applicable in this proceeding. See, e. g. Kirkman v. Duke Power Company, 64 Report of the North Carolina Utilities Commission, Orders and Decisions 89 (1974); Camp Gwynn Valley v. Duke Power Company, Docket No. E-7, Sub 414, (Order issued on April 4, 1988); and Crohn, et al. v. Duke Power Company Docket No. E-7, Sub 430 (Order issued on October 28, 1988). The Commission further notes that the "arbitrary and capricious" standard is applicable to transmission line locations in eminent domain proceedings. Duke Power Co. v. Ribet, 25 N.C. App. 87, 212 S.E.2d 182 (1975). The Commission hereby reaffirms the standard announced in the cases described above. Federal Courts have concluded that a federal agency, in applying the "arbitrary and capricious" standard in environmental matters, must take a "hard look" at the environmental consequences of the proposed action and of any reasonable alternatives thereto. Natural Resources Defense Council v. Morton, 458 F.2d 827, 838 (1972), quoted with approval and Kleppe v. Sierra Club, 427 U.S. 390 (1976).

In the Camp Gwynn case, after reviewing the applicable authorities, including the Kirkman case and the Environmental Policy Act, the Commission found and concluded:

> The abuse of discretion standard is applicable to this proceeding. The Commission must take a "hard look" and determine whether or not Duke acted arbitrarily and unreasonably in locating and siting the proposed transmission line in question, taking into account the environmental consequences of the proposed line and any reasonable alternative routes, the cost associated therewith, and the ability of Duke to efficiently serve its load.

Mr. Horney contends that MEC was arbitrary and capricious in locating the proposed corridor route for its new transmission line as complained of in this proceeding. To the contrary, MEC contends that it followed appropriate design criteria and reasonable standards of judgment in selecting the presently proposed corridor route location. The Commission concludes that MEC did not act arbitrarily, capriciously or unreasonably in locating the proposed corridor route of the new Beech Mountain transmission line.

The primary reasons for the Commission's ultimate conclusions are found in the Findings of Fact listed heretofore, and in the discussion of the Evidence and Conclusions sections for these Findings of Fact. Some, but not all, of these findings are the following: There is a critical need and demand for the project; planning for the proposed new transmission line and substation began many years ago; both TVA and REA have approved the project; there is a great danger of loss of adequate and reliable service to the public if the project is not rapidly completed; MEC followed appropriate standards of engineering design and appropriate policies of corridor route location; MEC, itself, weighed and evaluated each of the primary alternative corridor locations supported by Mr. Horney; for numerous and valid reasons, each of these proposed alternative corridor locations were deemed unacceptable by MEC; the corridor route presently proposed by MEC meets the relevant design criteria presented at the hearing by MEC; the MEC-proposed corridor location, while somewhat longer than the two alternatives, would actually cost less, would have a smaller impact on the environment, including existing and proposed developments, and, at least as to Horney Alternate II, would avoid the situation where MEC would have "all of its eggs in one basket".

The Commission concludes that MEC reasonably and fairly considered the environmental consequences of its proposed line with respect to the preferred and alternate routes, the costs associated therewith, and the ability of MEC to efficiently serve its growing load in and around the Beech Mountain-Banner Elk area. The Commission further concludes that the Complainant has not met his burden of proof to show that MEC acted arbitrarily, capriciously or unreasonably in siting the line. It would be extremely difficult, if not impossible, to site the transmission line in a manner that would satisfy everyone. The Commission is of the opinion, however, that MEC has reasonably and fairly considered and balanced all of the important factors in siting the transmission line at issue in this case, including the overall environmental impact of the line. Accordingly, this Order will issue dismissing the Complaint and closing this Docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 20

Both MEC and NCEMC filed Motions to Dismiss in this docket, asserting that the Commission had no jurisdiction to hear the complaint of Mr. Horney. The Commission scheduled oral argument on this issue, which was held on May 16, 1990, and thereafter on July 31, 1990, the Commission issued an Order concluding that it did have the jurisdiction to hear and determine the complaint of Mr. Horney in this docket. The Commission is of the opinion, and so concludes, that it should reaffirm its Order of July 31, 1990. The provisions of that Order will not be recited here, but are incorporated herein by reference as if fully set out.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 21

In his brief, filed November 26, 1990, the Complainant presented the following as Question II:

"Does Mountain Electric Cooperative, Inc., have authority, without the consent of Complainant to acquire by eminent domain a portion of the yard of Complainant for the purpose of constructing a transmission line."

In its brief, MEC took issue with the Complainant on this matter and asserted that the Commission does not have jurisdiction to determine this issue. The Commission agrees that Question II presented by the Complainant is a matter properly to be considered by the civil courts of the State and is not a matter that can be decided by the Commission. Accordingly, the Commission will not consider or rule upon Question II of Complainant's brief.

IT IS, THEREFORE, ORDERED as follows:

1. That the Complaint in this Docket be denied and that this Docket is hereby closed.

2. That the Order of July 31, 1990, in this docket be reaffirmed.

ISSUED BY ORDER OF THE COMMISSION.
This the 28th day of January 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Sandra J. Webster, Chief Clerk

DOCKET NO. E-2, SUB 603

In The Matter Of Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Electric Rates and Charges Pursuant to N.C.G.S. § 62-133.2 and NCUC Rule R8-55	ORDER APPROVING NET FUEL CHARGE RATE REDUCTION

HEARD: Tuesday, August 6, 1991, at 9:30 a.m., Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sarah Lindsay Tate, Presiding, Commissioners Robert O. Wells, and Allyson K. Duncan

APPEARANCES:

For the Applicant:

Robert W. Kaylor, Patterson, Dilthey, Clay, Cranfill, Sumner & Hartzog, Post Office Box 310, Raleigh, North Carolina 27602-0310

Len S. Anthony, Associate General Counsel, Carolina Power & Light Company, Post Office Box 1551, Raleigh, North Carolina 27602

For the Public Staff:

Vickie L. Moir, Staff Attorney, Public Staff North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Ms. Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629
For: The Using and Consuming Public

For the Carolina Industrial Group for Fair Utility Rates-II:

Ralph McDonald, Bailey & Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605-2865

For the Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon, & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28655

BY THE COMMISSION: On June 7, 1991, Carolina Power & Light Company (CP&L or the Company) filed an Application for a change in rates based solely on the cost of fuel in accordance with the provisions of Section 62-133.2 of the North

Carolina General Statutes (N.C.G.S.) and Commission Rule R8-55. In its Application, CP&L proposed an increment of 0.054 cents per kWh (0.056 cents per kWh including gross receipts tax) to the base factor of 1.276 cents per kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537. The preliminary fuel factor recommended by the Company of 1.330 cents per kWh was based on the adjusted historical 12-month test period ending March 31, 1991 and normalization of nuclear generation. The Company also requested a decrement of 0.012 cents per kWh (0.012 cents per kWh including gross receipts tax) for the Experience Modification Factor (EMF) to refund approximately $3.2 million of excess fuel revenues collected (plus interest) during the period April 1, 1990 to March 31, 1991. The Company proposed that the EMF rider be in effect for a fixed 12-month period. The net effect of the changes recommended by the Company results in a reduction of 31 cents per 1000 kWh's usage.

On June 28, 1991, the Commission issued its Order Scheduling Hearing and Requiring Public Notice and establishing certain filing dates.

The Attorney General, the Carolina Industrial Group for Fair Utility Rates (CIGFUR II) and the Carolina Utility Customer Association, Inc. (CUCA) each filed timely notices to intervene which interventions were allowed by the Commission. The intervention of the Public Staff is noted pursuant to NCUC Rule R1-19(e).

On July 17, 1991, Dennis Nightingale filed an affidavit to be used in evidence on behalf of the Public Staff in accordance with N.C.G.S. §62-68.

On July 19, 1991, the Company filed the affidavits of publication showing that public notice had been given as required by the Commission Order.

The case-in-chief came on for hearing as ordered on August 6, 1991 at 9:30 a.m. CP&L presented the testimony and exhibits of David R. Nevil, Manager - Rates & Energy Services Department. The Public Staff presented the affidavit and exhibits of Dennis J. Nightingale, Director, Electric Division. No other witnesses appeared at the hearing.

All parties to the proceeding were provided an opportunity to file proposed orders with the Commission on or before August 26, 1991.

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 (Commission). CP&L is engaged in the business of generating, transmitting, and selling electric power to the public of North Carolina. CP&L is lawfully before this Commission based upon its application filed pursuant to N.C.G.S. §62-133.2.

2. The test period for purposes of this proceeding is the 12-month period ended March 31, 1991.

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

4. The test period per books system sales are 39,492,663,520 kWh.

5. The test period per book system generation resource is 44,217,527 MWHs and is broken down by type as follows:

	MWHs
Purchase - Cogeneration	2,469,865
Purchase - American Electric Power (AEP)	1,903,673
Purchase - Southeastern Power Authority (SEPA)	226,168
Purchase - Other	421,931
Hydro	841,814
Coal	22,099,895
IC	33,306
Nuclear	16,801,860
Off-System Sales	(580,985)
TOTAL	44,217,527

6. The adjusted test period sales of 39,432,739,043 kWh results from adjustments to per book sales of a negative customer growth of 95,489,741 kWhs, a positive 352,524,456 kWhs associated with weather normalization and a negative 316,959,192 kWhs associated with normalization of SEPA and North Carolina Eastern Municipal Power Agency (Power Agency or NCEMPA) transactions.

7. The adjusted test period system generation for use in this proceeding is 44,491,844 MWHs.

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

   A. The coal fuel price is $18.56/MWH.
   B. The IC turbine fuel price is $113.26/MWH.
   C. The nuclear fuel price is $5.03/MWH.
   D. The fuel price for AEP purchase is $12.31/MWH.
   E. The fuel price for other purchases is $18.99/MWH.
   F. The fuel price for off-system sales is $21.03/MWH.

9. The system normalized nuclear capacity factor appropriate for use in this proceeding for billing purposes is 66.1 percent.

10. The adjusted test period fuel expense for use in this proceeding is $524,344,468.

11. The proper fuel factor for this proceeding is 1.330¢/kWh, excluding gross receipts tax.

12. The Company's North Carolina test period jurisdictional fuel expense overcollection was $2,758,638. The adjusted North Carolina jurisdictional test year sales are 25,601,815,770 kWh.

13. Interest expenses associated with the overcollection of test period fuel revenues amount to $402,761.

14. The Company's Experience Modification Factor (EMF) is a decrement of .012 cents per kWh (including gross receipts tax the factor remains at .012 cents per kWh after rounding).

15. The Company's operation of its base load nuclear and fossil plants was reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence for Finding of Fact No. 1 is essentially informational, procedural, and jurisdictional in nature and is not controversial.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

N.C.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 NCUC Rule 8-55(b), the Commission has prescribed the 12 months ending March 31 as the test period for CP&L. All prefiled exhibits and testimony submitted by the Company in support of its Application utilized the 12 months ended March 31, 1991 as the test year for purposes of this proceeding.

The test period proposed by the Company was not challenged by any party and the Commission concludes that the test period which is appropriate for use in this proceeding is the 12 months ended March 31, 1991, adjusted for weather normalization, customer growth, generation mix, and normalization of SEPA and NCEMPA transactions.

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 this Commission. Commission Rule R8-52(b) requires each utility to file a Fuel Procurement Practice Report at least once every 10 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 fossil and nuclear fuels were filed in the Fuel Procurement Practices Report dated February 1987 filed in Docket No. E-100, Sub 47. In addition, the Company files monthly reports as to the Company's fuel costs pursuant to Rule R8-52(a) under its present procurement practices. No party offered any testimony contesting the Company's fuel procurement and power purchasing practices.

The Commission concludes that CP&L's fuel procurement and power purchasing practices and procedures were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for Finding of Fact No. 4 can be found in the exhibits of Company witness Nevil. The Company has reported in its monthly fuel reports to the Commission that meter level sales were 39,492,663,520 kWhs for the test period. This level of sales was not challenged by any party and was used as the basis for the test period adjustments.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding can be found in the workpapers of Company witness Nevil. The per books total system generation value of 44,217,527 MWHs (including Power Agency ownership) reflects the generation resources available to serve the CP&L customers. This generation level was not challenged by any party.

The test period per book generation is broken down by type as follows:

	MWHs
Purchase - Cogeneration	2,469,865
Purchase - (AEP)	1,903,673
Purchase - (SEPA)	226,168
Purchase - Other	421,931
Hydro	841,814
Coal	22,099,895
IC	33,306
Nuclear	16,801,860
Off-System Sales	(580,985)
TOTAL	44,217,527

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence supporting this finding is contained in the testimony and exhibits of Company witness Nevil. The Company calculated kWh adjustments for customer growth, normal weather, SEPA normalization, and Power Agency supplemental totaling a negative 59,924,477 kWhs. Those kWh adjustments were adopted by the Public Staff and used in their calculations.

The Company calculated a negative customer growth adjustment of 95,489,741 kWhs for the system and a negative 205,059,841 kWhs for the NC Retail jurisdiction. The method employed by the Company in making this calculation utilizes the end-of-period number of customers. This method has also been used by the Company and adopted by this Commission in the past two fuel cases.

The Company calculated a weather normalization adjustment of 352,524,456 kWhs on a system basis and 266,676,418 kWhs for the NC Retail jurisdiction.

The Company calculated a SEPA normalization adjustment of 39,946,210 kWhs for the normalization of kWh deliveries from the SEPA hydro project based on a 24-year history. These kWhs are delivered to the wholesale customers and Power Agency.

The Company made a negative adjustment of 356,905,402 kWhs for the supplemental kWh sales to Power Agency. The Power Agency has ownership in three of the Company's nuclear units: Brunswick 1, Brunswick 2, and Harris.

Adjustments to the ownership/supplemental kWhs for Power Agency are necessary each time the nuclear capacity factors are normalized to a level that is different from the test year actual performance.

The total of all the adjustments to kWh meter level sales is a negative 59,924,477 kWhs. When this adjustment is subtracted from the level of per book meter kWh sales found appropriate in Finding of Fact No. 4, the results total adjusted kWh sales of 39,432,739,043 kWhs. The Commission finds these kWh adjustments appropriate and consistent with the adjustments made in past cases, and notes that no party challenged the Company's calculations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding is contained in the testimony and exhibits of Company witness Nevil and Public Staff witness Nightingale.

The Company applied losses to the kWh adjustments calculated for customer growth and weather normalization and determined that these adjustments total 274,317 MWHs at the generation level. The adjusted generation level of 44,491,844 MWHs is determined by adding the adjustments to the per book values. The Commission finds that the proper level of adjusted generation is 44,491,844 MWHs, and notes that no party took issue with the adjustments calculated by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence and conclusions for this finding of fact is found in the testimony and exhibits of Company witness Nevil and Public Staff witness Nightingale.

The Company's fuel factor calculation utilized the burned fuel prices experienced in March 1991, the last month of the test period for coal, nuclear, and Internal Combustion Turbine (IC) prices. The prices for the AEP purchase, other purchases, and sales were based on test year average fuel cost. The prices utilized by the Company are as follows:

	$/MWH
Coal	18.56
IC	113.26
Nuclear	5.03
AEP Purchase	12.31
Other Purchases	18.99
Sales	21.03

The Public Staff calculated updated prices for coal and IC using May 1991 data as follows: Coal = $19.02/MWH and IC = $110.45/MWH. The Public Staff adopted the Company's prices for nuclear, purchases and sales. Witness Nightingale did not recommend adoption of the May fossil prices because they produced a fuel factor higher than the one proposed by the Company.

The Commission concludes that the March 1991 prices as proposed by CP&L are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 9, 10 & 11

The evidence supporting these findings is contained in the testimony and exhibits of Company witness Nevil and Public Staff witness Nightingale.

In Nevil Exhibit No. 3, the Company normalized the 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 1985-1989 for boiling water reactors (BWRs) and pressurized water reactors (PWRs). The capacity factors of Brunswick Unit Nos. 1 and 2, both BWRs, were normalized at 52.3% and the capacity factors of the Robinson and Harris Units, both PWRs, were normalized at 64.81%. The Company's normalization calculations result in a system nuclear capacity factor of 58.44% and produces a fuel factor of 1.393¢/kWh. However, in an effort to more accurately match fuel costs with fuel revenues, CP&L recommended approval of a fuel factor of 1.330¢/kWh. The 1.330¢/kWh factor is calculated using a 66.1% system nuclear capacity factor for billing purposes and March burned fuel costs. The total fuel expense resulting from this calculation equals $524,344,468. The 1.330 cents per kWh factor is derived by dividing the fuel expense by adjusted kWh sales.

Company witness Nevil testified that the consideration of numerous factors caused the Company to request approval of a fuel factor of 1.330¢/kWh. The considerations included the Company's five-year average nuclear capacity factor of 66.7%, the Company's forecasted nuclear capacity factor for the next 12 months of 71%; the fact that during the test period, CP&L's actual fuel expense was 1.330¢/kWh; the effects of weather upon the Company's system; and the amount of customer growth the Company projects during the coming year.

Public Staff witness Nightingale testified that he calculated a fuel factor for the Company of 1.418¢/kWh using May 1991 burned fuel costs and the same five-year NERC data used by the Company in calculating a fuel factor of 1.393¢/kWh. The Public Staff's calculation of a fuel factor of 1.418¢/kWh is fully consistent with the Public Staff's position in past CP&L fuel cases. However, since it is the Public Staff's policy not to recommend a fuel factor greater than that requested by the Company, Public Staff witness Nightingale recommended adoption of the Company's proposed factor.

No other witness or party presented any evidence on this issue or recommended a different fuel factor or nuclear capacity factor. Based on the evidence of record, the Commission concludes that a fuel factor of 1.330¢/kWh using a 66.1 percent nuclear capacity factor and March burned fuel cost as proposed by the Company and supported by the Public Staff is just and reasonable and should be approved. This factor is 0.054¢/kWh higher than the base fuel factor of 1.276¢/kWh approved in CP&L's last general rate case, Docket No. E-2, Sub 537. The calculation of the 1.330¢/kWh fuel factor is shown in the following table:

	MWH Gen	$/MWH	Fuel Cost
Coal	21,269,371	18.56	$394,759,526
Nuclear	17,979,067	5.03	90,434,708
IC	32,054	113.26	3,630,436
Hydro	719,475	-	-
Purchases: Co-Gen	2,666,825	-	42,383,706
AEP	1,795,700	12.31	22,105,067
SEPA	182,428	-	-
Other	406,075	18.99	7,711,364
Sales	(559,151)	21.03	(11,758,946)
Total Adjusted	44,491,844		$549,265,861
NCEMPA Adjustments:			
Nuclear Ownership			(12,485,411)
Coal Ownership			(15,232,581)
Harris Buyback			1,383,849
Mayo Buyback			1,412,750
Net Fuel Cost			$524,344,468
kWh for Fuel Factor			39,432,739,043
Fuel Factor (¢/kWh)			1.330

On August 26, 1991, the Company filed its report and study of the Maximum Dependable Capacity (MDC) ratings of all Carolina Power and Light Company's nuclear generating units. Since this study was filed after the close of the hearing in this matter, it cannot be used as evidence in this proceeding. The Commission concludes that the Public Staff and all other interested parties should review this report and file any appropriate testimony in the company's next fuel clause proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12 & 13

The evidence supporting this finding is contained in the testimony and exhibits of Company witness Nevil and Public Staff witness Nightingale.

Company witness Nevil testified that the Company overcollected its fuel expense by $2,758,638 during the test year from the fuel factors approved in the past two fuel cases, Docket Nos. E-2, Sub 562 and Sub 579. Mr. Nevil calculated interest for this overcollection totaling $402,761 in accordance with NCUC Rule R8-55(c)(5). Public Staff witness Nightingale testified that he reviewed the Company's calculation of the EMF and interest and agreed with the results.

The Company is proposing to refund the EMF and interest to the customers over a 12-month period using the adjusted kWh sales for the retail customers. The Company determined the adjusted NC Retail kWh sales to be 25,601,815,770 kWhs.

The Commission concludes that the Company's calculation of the EMF and interest totaling $3,161,399 should be refunded to the customers over a 12-month period and further notes that no party opposed the calculation. This refund should be in the form of a separate rider that will expire 12 months from the date of this order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence supporting this finding can be found in the direct testimony of Company witness Nevil and Public Staff witness Nightingale.

The Company is proposing a decrement of 0.012¢/kWh (0.012¢/kWh with gross receipts) to refund $3,161,399 of overrecovered fuel revenues (plus interest) experienced during the period April 1, 1990 through March 31, 1991. Public Staff witness Nightingale testified that he reviewed the EMF calculation and recommended that the EMF factor, as proposed by the Company, be adopted.

North Carolina General Statute 62-133.2(d) provides that 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..." Further, amended Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

No other party offered any evidence contesting the Company's calculations. The Commission concludes that the EMF decrement of 0.012¢/kWh (0.012¢/kWh with gross receipts tax) is appropriate for use in this proceeding. The EMF decrement shall remain in effect for a fixed 12-month period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence for this finding can be found in the Company's Application and testimony of CP&L witness Nevil.

The Company files with this Commission monthly Fuel Reports and Base Load Power Plant Performance Reports. These reports were filed in Docket No. E-2, Sub 573 for calendar year 1990 and Docket No. E-2, Sub 598 for calendar year 1991. Witness Nevil testified that the Company met the standard for prudent operation as set forth in Commission Rule R8-55. No party offered testimony or evidence challenging the Company's operation of its base load plants. Based on the evidence, the Commission concludes that the operation of the Company's Base Load nuclear and fossil plants was reasonable and prudent during the test period.

IT IS, THEREFORE, ORDERED as follows:

1. That, effective for service rendered on and after September 15, 1991, CP&L shall adjust the base fuel component in its North Carolina retail rates by an amount equal to a 0.054¢/kWh increment (0.056¢/kWh including gross receipts tax) from 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 a decrement of 0.012¢/kWh (0.012¢/kWh including gross receipts tax). The EMF is to remain in effect for a 12-month period beginning September 15, 1991.

3. 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 five (5) working days from the date of this Order.

4. That CP&L shall notify its North Carolina retail customers of the fuel adjustments approved herein by including the "Notice to Customers of Net Rate Reduction" attached as Appendix A as a bill insert with bills rendered during the Company's next normal billing cycle.

5. That the Public Staff and all other interested parties should review the Company's report and study of the Maximum Dependable Capacity ratings of all Carolina Power and Light Company's nuclear generating units and file any appropriate testimony in the company's next fuel clause proceeding.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. E-2, SUB 603

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Power & Light Company for Authority to Adjust Its Electric Rates and Charges Pursuant to G.S. § 62-133.2 and NCUC Rule R8-55	)	NOTICE TO CUSTOMERS OF NET RATE REDUCTION

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order on September 12, 1991, after public hearings, approving a fuel charge net rate reduction of approximately $7.9 million in the rates and charges paid by the retail customers of Carolina Power & Light Company in North Carolina. The net rate reduction will be effective for service rendered on and after September 15, 1991. The rate decrease was ordered by the Commission after review of CP&L's fuel expense during the 12-month test period ended March 31, 1991, 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 Commission Order will result in a monthly net rate reduction of $0.31 for a typical residential customer using 1,000 kWh per month.

ISSUEO BY ORDER OF THE COMMISSION.
This the 12th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-7, SUB 481

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Duke Power Company Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	)))	ORDER APPROVING NET FUEL CHARGE RATE INCREASE

HEARD: Thursday, May 2, 1991, at 10:00 a.m., Commission Hearing Room, Dobbs Building, 430 N. Salisbury Street, Raleigh, North Carolina.

BEFORE: Commissioner Sarah Lindsay Tate, Presiding; Commissioners Julius A. Wright and Charles H. Hughes.

APPEARANCES:

For Duke Power Company:

Robert W. Kaylor, Patterson, Dilthey, Clay, Cranfill, Sumner & Hartzog, Post Office Box 310, Raleigh North Carolina 27602-0310

and

Karol E. Page, Senior Attorney, Duke Power Company, 422 South Church Street, Charlotte, North Carolina 28242-0001

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, Post Office Drawer 1269, Morganton, North Carolina 28655.

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, Thomas Zweigart, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602.

For the Public Staff:

James D. Little, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520.

BY THE COMMISSION: On February 2, 1991, Duke Power Company (Duke or the Company) filed its application pursuant to G.S. 62-133.2 and NCUC Rule R8-55 relating to fuel charge adjustments for electric utilities. In its February 28, 1991, application Duke proposed a fuel factor of 1.1833¢/kWh (including nuclear fuel disposal costs and excluding gross receipts tax), which is an increase of .0168¢/kWh from the base fuel factor of 1.1665¢ set in the Company's last general rate case, Docket No. E-7, Sub 408. The Company further adjusted the proposed factor by a decrement excluding gross receipts tax of .0851¢/kWh and .0128¢/kWh for the Experience Modification Factor (EMF) and EMF interest, respectively, for a net fuel factor of 1.0854¢/kWh.

On March 20 the Commission issued its Order requiring public notice.

The Attorney General and the Carolina Utility Customers Association, Inc. (CUCA) each filed timely notices to intervene, which interventions were allowed by the Commission. The intervention of the Public Staff is noted pursuant to NCUC Rule R1-19(e).

At the public hearing, Duke presented the testimony and exhibits of William R. Stimart, Vice President of Rates and Regulatory Affairs. The Public Staff presented the testimony and exhibits of Thomas S. Lam, Engineer, Electric Division. No other witnesses appeared at the hearing.

Affidavits of Publication were filed by the Company showing that public notice had been given as required by the Commission Order.

Based upon the verified application, the evidence adduced at the hearing, the Orders in Docket Nos. E-7, Subs 408, 417, 434, 447, and 462, of which the Commission takes judicial notice, and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. Duke Power 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 this Commission. Duke is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in North Carolina. Duke is lawfully before this Commission based upon its application pursuant to G.S. 62-133.2.

2. The test period for purposes of this proceeding is the twelve-months ended December 31, 1990.

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

4. The test period per book system sales are 66,761,941 MWH.

5. The test period per book system generation is 71,203,560 MWH and is broken down by type as follows:

	MWH
Coal	27,262,577
Oil & Gas	52,986
Light Off	-
Nuclear	32,913,871
Hydro	2,182,186
Net Pumped Storage	-303,576
Purchased Power	672,972
Interchange in	529,894
Interchange out	-1,083,994
Catawba Contract Purchases	8,657,403
Catawba Interconnection Agreements	299,820
Interchange	19,421
Total Generation	71,203,560

6. The system normalized nuclear capacity factor for use in this proceeding is 66.20% and its associated generation is 29,530,064 MWH.

7. The adjusted test period sales of 66,211,826 MWH results from an additional 558,429 MWH of customer growth, 327,012 MWH associated with weather normalization, and -1,435,556 MWH associated with the adjustment for Catawba retained generation added to test period system sales of 66,761,941 MWH.

8. The adjusted test period system generation for use in this proceeding is 71,404,734 MWH and is broken down by type as follows:

	MWH
Coal	33,017,410
Oil & Gas	40,184
Light Off	-
Nuclear	29,530,064
Hydro	1,859,100
Net Pumped Storage	-382,554
Purchased Power	672,972
Interchange in	529,894
Interchange out	-1,083,994
Catawba Contract Purchases	7,221,658
Total Generation	71,404,734

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

A. The coal fuel price is $17.43/MWH.

B. The oil and gas fuel price is $113.51/MWH.

C. The appropriate Light Off fuel expense is $4,222,000.

D. The nuclear fuel price is $5.57/MWH.

E. The purchased power fuel price is $13.41/MWH.

F. The interchange in fuel price is $25.76/MWH.

G. The interchange out fuel price is $17.51/MWH.

H. The Catawba Contract Purchase fuel price is $5.80/MWH.

10. The adjusted test period system fuel expense for use in this proceeding is $781,675,000.

11. The proper fuel factor for this proceeding is 1.1806¢/kWh excluding gross receipts tax.

12. The Company's North Carolina test period jurisdictional fuel expense overcollection was $34,550,000. The adjusted North Carolina jurisdictional test year sales are 40,619,162 MWH.

13. Interest expenses associated with the overcollection of test period fuel revenues amount to $5,182,000.

14. The Company's Experience Modification Factor (EMF) is a decrement of .0851¢/kWh (excluding gross receipts tax). The EMF interest decrement is .0128¢/kWh (excluding gross receipts tax).

15. The final net fuel factor is 1.0827¢/kWh, excluding 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 controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

NCGS 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an annual fuel charge adjustment proceeding for an historical 12-month test period. In NCUC Rule R8-55(b), the Commission has prescribed the 12 months ending December 31 as the test period for Duke. The Company's filing was based on the 12 months ended December 31, 1990.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

NCUC Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, plus each time the utility's fuel procurement practices change. Procedures related to Duke's procurement of fossil and nuclear fuels were filed in Docket No. E-100, Sub 47, and remained in effect throughout the 12 months ended December 31, 1990. In addition, the Company files monthly reports of its fuel costs pursuant to NCUC Rule R8-52(a).

No party offered direct testimony contesting the Company's fuel procurement and power purchasing practices. Based upon the evidence, the Commission concludes that these practices were reasonable and prudent during the test period.

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

The evidence for these findings of fact is found in the testimony of Company witness Stimart and Public Staff witness Lam.

Company witness Stimart testified that the test period per books system sales were 66,761,941 MWH and test period per book system generation was 71,203,560 MWH. Public Staff witness Lam accepted these levels of test period per book system sales and generation for use in his fuel computation. The test period per book generation is broken down by type as follows:

	MWH
Coal	27,262,577
Oil & Gas	52,986
Light Off	-
Nuclear	32,913,871
Hydro	2,182,186
Net Pumped Storage	-303,576
Purchased Power	672,972
Interchange in	529,894
Interchange out	-1,083,994
Catawba Contract Purchases	8,657,403
Catawba Interconnection Agreements	299,820
Interchange	19,421
Total Generation	71,203,560

Mr. Stimart testified that Duke achieved a system nuclear capacity factor of 72% for the test period. Mr. Stimart normalized the system nuclear capacity factor to a level of 63.80%, which is the latest North American Electric Reliability Council's (NERC) 5-year nuclear capacity factor for pressurized water reactors (PWR) by size. Mr. Lam testified that the system nuclear capacity factor of 72%, as achieved by the Company, was high and should be normalized to 66.20%, which is an average of the Company's lifetime system nuclear capacity factor of 67.59% and the latest NERC 5-year nuclear capacity factor for all PWR's of 64.81%. Mr. Lam's method of calculating the system nuclear capacity factor is the method recommended by the Public Staff and adopted by the Commission in Duke's previous fuel adjustment hearing, Docket No. E-7, Sub 462. The Attorney General also supports use of a 66.2% normalized nuclear capacity factor in this proceeding.

Based upon the agreement of the Company and the Public Staff as to the appropriate numbers, and noting the absence of evidence presented to the contrary, the Commission concludes that the test period level of per book sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that, because of the ongoing level of overcollection of fuel revenues, the 66.20% normalized system nuclear capacity factor and its associated generation of 29,530,064 MWH is reasonable and appropriate for use in this proceeding for reasons stated by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony of Company witness Stimart and Public Staff witness Lam.

Witness Stimart adjusted total per book test period sales by -400,680 MWH. This adjustment is the sum of adjustments for weather, customer growth, and Catawba retained of 327,012 MWH, 558,429 MWH, and -1,286,121 MWH, respectively. The level of Catawba retained is associated with the Company's normalized system nuclear capacity factor of 63.80%.

Witness Lam accepted Mr. Stimart's adjustment for weather and customer growth, but adjusted Catawba retained to a level of-1,435,556 MWH and arrived at a total adjustment of -550,115 MWH. This level of Catawba retained is associated with the Public Staff's normalized system nuclear capacity factor of 66.20%. Mr. Lam calculated an adjusted test period sales level of 66,211,826 MWH.

The Commission concludes that the adjustment for weather of 327,012 MWH and customer growth of 558,429 MWH, as presented by the Company and reviewed and accepted by the Public Staff, is reasonable and appropriate for use in this proceeding. The Commission also concludes that the adjustment for Catawba retained of -1,435,556 MWH, associated with the system nuclear capacity factor of 66.20% accepted as reasonable and appropriate by the Commission in Finding of Fact No. 6, as presented by the Public Staff, is both reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is found in the testimony of Company witness Stimart and Public Staff witness Lam.

Witness Stimart presented an adjustment to per book generation, due to weather, customer growth, and a Catawba retained, based on a 63.80% normalized system nuclear capacity factor, of 360,502 MWH, to arrive at his adjusted generation level of 71,564,062 MWH.

Mr. Lam presented an adjustment to per book generation, due to weather, customer growth, and a Catawba retained based on a 66.20% normalized system nuclear capacity factor, of 201,174 MWH, to arrive at his adjusted generation level of 71,404,734 MWH.

The Commission concludes, after finding the Public Staff's normalized system nuclear capacity factor of 66.20% reasonable and appropriate in Finding of Fact No. 6 and adjustments to sales reasonable and appropriate in Finding of Fact No. 7, that the Public Staff adjustment to generation of 201,174 MWH and adjusted generation level of 71,404,734 MWH are both reasonable and appropriate for use in this proceeding and is broken down by type as follows:

	MWH
Coal	33,017,410
Oil & Gas	40,184
Light Off	-
Nuclear	29,530,064
Hydro	1,859,100
Net Pumped Storage	-382,554
Purchased Power	672,972
Interchange in	529,894
Interchange out	-1,083,994
Catawba Contract Purchases	7,221,658
Total Generation	71,404,734

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 9 - 15

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Stimart and Public Staff witness Lam.

Witness Stimart's testimony recommended fuel prices as follows: (1) coal price of $17.05/MWH; (2) oil and gas price of $68.86/MWH; (3) light-off fuel expense of $4,222,000; (4) nuclear fuel price of $5.57/MWH; (5) purchased power fuel price of $13.41/MWH; (6) interchange-in fuel price of $25.76/MWH; (7) interchange-out fuel price of $17.51/MWH; and (8) Catawba Contract purchase fuel price of $5.80/MWH.

Mr. Lam in his testimony, accepted Mr. Stimart's expense and fuel prices for light-off fuel expense, nuclear fuel price, purchased power fuel price, interchange-in fuel price, interchange-out fuel price, and Catawba Contract purchase fuel price, but rejected the fuel prices for the other types of generation. Mr. Lam recommended fuel prices as follows: (1) coal price of $17.43/MWH based on March 1991 burn price, and (2) oil and gas price of $113.51/MWH based on February 1991 burn price because there was no generation in March 1991. Mr. Lam made these recommendations to obtain the most up-to-date prices on these fuels, and to more accurately reflect the trend in fuel prices. Mr. Lam stated that the use of test year fuel prices for these two fuel categories in effect considers the price of fuel from January 1990 in setting rates to be billed July 1991 through June 1992. In response to a question on the use of a single month's coal price, specifically March 1991, Mr. Lam explained that the burn price he utilized is actually a weighted price of coal for the last three or four months. He further noted that the March 1991 coal price he utilized was approximately 2% higher than the test year average coal price.

The Attorney General takes the position that "standard ratemaking procedures" should be followed and that test year average fossil fuel costs should be used to calculate the fuel factor.

The Commission concludes that Company fuel expense and fuel prices accepted by the Public Staff and fuel prices recommended by the Public Staff are reasonable and appropriate for use in this proceeding for reasons stated by the Public Staff. While adopting the Public Staff's recommendation, the Commission notes that the gas price used by the Public Staff in developing total fuel costs, while within the range of reasonableness, appears to be at a level near the upper bound of said range. However, the impact on Duke's fuel costs of this price, versus that proposed by the Company, is de minimus when viewed in the context of total fuel costs. Further, the Commission notes that all components of fuel cost established in this proceeding are subject to true up procedures in effect for Duke. The Commission will review the gas price, and all other costs where appropriate, in the Company's pending general rate case proceeding.

Therefore, the Commission concludes that based upon prior findings and conclusions in this order, adjusted fuel test period expenses of $781,675,000 and the fuel factor of 1.1806¢/kWh, excluding gross receipts tax, are reasonable and appropriate for use in this proceeding. This approved base fuel factor is .0141¢/kWh higher than the current base fuel factor in effect of 1.1665¢/kWh, excluding gross receipts tax.

North Carolina General Statute 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..." Further, amended Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any overcollection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Both Company witness Stimart and Public Staff witness Lam testified that during the test year Duke over-recovered $34,550,000 in fuel revenues, that the EMF interest associated with the overcollection is $5,182,000, and that the adjusted North Carolina jurisdictional test year sales are 40,619,162 MWH. The $34,550,000 over-recovered fuel revenues and $5,182,000 of interest on the over-recovered fuel revenues are divided by the adjusted North Carolina jurisdictional sales of 40,619,162 MWH to arrive respectively at an EMF decrement of .0851¢/kWh (excluding gross receipts tax) and an EMF interest decrement of .0128¢/kWh (excluding gross receipts tax). The Commission concludes that there being no controversy, the EMF decrement of .0851¢/kWh (excluding gross receipts tax) and EMF interest decrement of .0128¢/kWh (excluding gross receipts tax) are reasonable and appropriate for use in this proceeding.

Accordingly, the fuel calculation incorporating the conclusions reached herein result in a final fuel net factor of 1.0827¢/kWh (excluding gross receipts tax) is shown in the following table:

	Adjusted Generation (MWH)	Fuel Price $/MWH	Fuel Dollars (000s)
Coal	33,017,410	17.43	$575,619
Oil and Gas	40,184	113.51	4,561
Light Off			4,222
Nuclear	29,530,064	5.57	164,482
Hydro	1,859,100		
Net Pumped Storage	-382,554		
Purchased Power	672,972	13.41	9,025
Interchange In	529,894	25.76	13,650
Interchange Out	-1,083,994	17.51	-18,981
Catawba Contract Purchases (including NFDC)	7,221,658	5.80	41,886
TOTAL	71,404,734		$794,464
Less: Intersystem Sales	-759,412		-12,789
Line Loss	-4,433,496		
System MWH Sales & Fuel Cost	66,211,826		$781,675
Fuel Factor ¢/kWh			1.1806
EMF ¢/kWh			-0.0851
EMF Interest ¢/kWh			-0.0128
FINAL FUEL FACTOR ¢/kWh			1.0827

IT IS, THEREFORE, ORDERED as follows:

1. That effective for service rendered on and after July 1, 1991, Duke shall adjust the base fuel cost approved in Docket No. E-7, Sub 408, in its North Carolina retail rates by an amount equal to a .0141¢/kWh increase (excluding gross receipts tax) and further that Duke shall adjust the resultant approved fuel cost by decrements of .0851¢/kWh and .0128¢/kWh for the EMF and EMF interest, respectively. The EMF and EMF interest portion are to remain in effect for a 12 month period beginning July 1, 1991.

2. That Duke shall file appropriate rate schedules and riders with the Commission in order to implement the fuel charge adjustments approved herein not later than 10 days from the date of this Order.

3. That Duke shall notify its North Carolina retail customers of the fuel adjustments approved herein by including the "notice to Customers of Net Rate Increase" 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 26th day of June 1991

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

APPENDIX A

DOCKET NO. E-7, SUB 481

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Duke Power Company Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities) NOTICE TO CUSTOMERS OF NET RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an order on June 27, 1991, after public hearings, approving a fuel charge net rate increase of approximately $28,400,000 on an annual basis in the rates and charges paid by the retail customers of Duke Power Company in North Carolina. The net rate reduction will be effective for service rendered on and after July 1, 1990. The rate increase was ordered by the Commission after review of Duke's fuel expense during the 12-month period ended December 31, 1990, 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 Commission's Order will result in a monthly net rate increase of approximately 70¢ each 1,000 kWh of usage per month.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. E-7, SUB 487

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Duke Power Company for Authority to Adjust and Increase Its Electric Rates and Charges) ORDER GRANTING PARTIAL RATE INCREASE

HEARD: Tuesday, August 20, 1991, in the Courtroom, Second Floor, McDowell County Courthouse, Main and Court Streets, Marion, North Carolina

Wednesday, August 21, 1991, in the Council Chambers, Charlotte-Mecklenburg Government Center, 600 East Fourth Street, Charlotte, North Carolina

Tuesday, August 27, 1991, in the Council Chambers, City Hall, 101 North Main Street, Winston-Salem, North Carolina

Wednesday, August 28, 1991, in the Courtroom 2A, Guilford County Courthouse, #2 Governmental Plaza, Greensboro, North Carolina

Monday, September 9, 1991, in the Council Chambers, City Hall, 101 City Hall Plaza, Durham, North Carolina

Tuesday, September 10, 1991, through Friday, September 13, 1991, and Monday, September 16, 1991, through Friday, September 20, 1991, in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman William W. Redman, Jr., Presiding; Commissioners Sarah Lindsay Tate and Julius A. Wright

APPEARANCES:

For Duke Power Company:

Steve C. Griffith, Jr., Executive Vice President and General Counsel, Ellen T. Ruff, Deputy General Counsel, Karol P. Mack, Senior Attorney, and W. Larry Porter, Associate General Counsel, Duke Power Company, 422 South Church Street, Charlotte, North Carolina 28242

and

Clarence W. Walker and Myles E. Standish, Kennedy Covington Lobdell & Hickman, 3300 NCNB Plaza, Charlotte, North Carolina 28280

For the City of Durham:

W. I. Thornton, Jr., City Attorney, and Gayle Moses, Assistant City Attorney, 101 City Hall Plaza, Durham, North Carolina 27701

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Drawer 1269, Morganton, North Carolina 28655

For North Carolina Industrial Energy Consumers:

Thomas W. Steed, Jr., Moore & Van Allen, P.O. Box 26507, Raleigh, North Carolina 27611

and

William A. Chesnutt, McNees, Wallace & Nurick, P.O. Box 1166, Harrisburg, Pennsylvania 17108

For Southern Environmental Law Center:

Oerb S. Carter, Jr., Staff Attorney, Southern Environmental Law Center, 137 East Franklin Street, Suite 404, Chapel Hill, North Carolina 27514

and

Jeffrey M. Gleason, Staff Attorney, Southern Environmental Law Center, 201 West Main Street, Suite 14, Charlottesville, Virginia 22901

For the North Carolina Department of Justice:

Jo Anne Sanford, Special Deputy Attorney General, Karen E. Long, Assistant Attorney General, Thomas D. Zweigart, Assistant Attorney General, Lorinzo L. Joyner, Assistant Attorney General, and Richard L. Griffin, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

For the Public Staff:

James D. Little and A. W. Turner, Jr., Staff Attorneys, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On April 12, 1991, Duke Power Company (also referred to as Duke, Applicant, or Company) filed an application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers to become effective on May 12, 199I.

On May 8, 1991, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings in Marion, Charlotte, Winston-Salem, Greensboro, Durham, and Raleigh.

The following parties made timely motions to intervene: the Carolina Utility Customers Association, Inc. (CUCA); the City of Durham; the Southern Environmental Law Center (SELC); and the North Carolina Industrial Energy Consumers (NCIEC). All were allowed to intervene by various orders of the Commission. The Attorney General and the Public Staff also intervened.

On August 23, 1991, the Public Staff moved for a prefiling deadline for Duke's rebuttal testimony. On August 28, 1991, Duke opposed the Public Staff's motion. On August 30, 1991, the Commission issued an order setting procedures for the hearing, including an order adopting Duke's recommendations for the prefiling of rebuttal testimony.

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

<u>Marion:</u> Ray Cantrell, William Jamison, Robert Austin, John Hendrick, Richard Whisenant, Kaye Anderson, Harriet Hailey, Gene Michelon

<u>Charlotte:</u> Wayne Beard and Paul Eich

<u>Winston-Salem:</u> Mary Parham, Teresa Garaventa, Selwyn Matthews, Patti Hoffman, Robert A. Vogler, W. F. Owens, George Potosnak, Jane Davis, Frank Shealy

<u>Greensboro:</u> Donald S. Rayle, Nathan Witherspoon, Chester Street, Caroline Myers, Brinford Bulla, W. L. Venable

<u>Durham:</u> Bill Kalkhof, Gary Hock, C. W. Vaughn, Michael W. Powell, Ken Griffin

The expert testimony was heard in Raleigh beginning September 10, 1991.

The Applicant presented the testimony and exhibits of the following witnesses: William S. Lee, Chairman and President of Duke; Roger G. Ibbotson, President of Ibbotson Associates, Inc.; Richard J. Osborne, Vice President of Finance for Duke; William R. Stimart, Vice President of Rates and Regulatory Affairs for Duke; and Donald H. Denton, Jr., Senior Vice President of Planning and Operating for Duke.

The Public Staff presented the testimony and exhibits of the following witnesses: Kevin W. O'Donnell, Financial Analyst, Economic Research Division of the Public Staff; James S. McLawhorn, Electric Engineer, Electric Division of the Public Staff; Benjamin R. Turner, Jr., Electric Engineer, Electric Division of the Public Staff; Thomas S. Lam, Electric Engineer, Electric Division of the Public Staff; Darlene P. Peedin, Staff Accountant, Accounting Division of the Public Staff; and Michael C. Maness, Supervisor, Electric Section of the Accounting Division of the Public Staff.

CUCA presented the testimony and exhibits of Nicholas Phillips, Jr., principal in the firm of Drazen-Brubaker & Associates, Inc.; and J. Bertram Soloman with GDS Associates, Inc.

NCIEC presented the testimony of Stephen J. Baron, President of Kennedy and Associates.

SELC presented the testimony of Susan E. Coakley, an independent consultant.

The Applicant presented the rebuttal testimony of the following witnesses: Dr. Ronald E. White, Senior Vice President of Foster Associates, Inc.; Dr. Edward W. Erickson, Professor of Economics at North Carolina State University; and William R. Stimart.

Following the hearing, proposed orders and briefs were timely filed by the parties. CUCA filed a Motion to Amend Brief on October 21, 1991. That Motion is allowed.

Based upon the verified application, the testimony and exhibits received into evidence at the hearings and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

Jurisdiction

1. Duke Power Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in a broad area of central and western North Carolina with its principal office in Charlotte.

2. Duke is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133.

3. The test period is the 12-month period ended December 31, 1990, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. Duke by its general rate case application sought an increase in its basic rates and charges to its North Carolina retail customers of $222,594,000, or 9.22%.

Quality of Service

5. The overall quality of electric service provided by Duke to its North Carolina retail customers is good.

Cost Allocation

6. The Summer Coincident Peak cost allocation methodology should be adopted for allocating costs between jurisdictions in this proceeding. Consequently, each finding and conclusion in this Order which deals with the overall level of rate base, revenues, and expenses for the North Carolina retail jurisdiction has been determined based upon the Summer Coincident Peak cost allocation methodology as described in this Order.

7. The Summer Coincident Peak method is the most appropriate method for allocating costs between retail customer classes within the North Carolina retail jurisdiction in this proceeding. Consequently, each finding and conclusion in this Order which deals with the level of rate base, revenues, and expenses for each North Carolina retail customer class has been determined based upon the Summer Coincident Peak cost allocation methodology as described in this Order.

8. The Company should be required to revise its future cost allocation studies in order to reflect a separate rate of return for each of the major rate schedules adopted herein.

9. The Company should be required to present cost allocation studies with its next general rate case which utilize the following methodologies: (a) Summer Coincident Peak; and (b) Summer/Winter Peak and Average.

10. It is reasonable and appropriate to adjust the jurisdictional cost of service study utilized in this proceeding to reflect the projected limitation on Catawba Retained Capacity and Energy due to provisions in the Catawba Agreements related to the Cooperative Buyers' demands. Consequently, each finding in this Order which deals with the overall level of rate base, revenues, and expenses for North Carolina retail cost of service has been determined in a manner reflective of those adjustments.

11. It is reasonable and appropriate to adjust the jurisdictional cost of service study utilized in this proceeding to reflect a 72% nuclear capacity factor. Consequently, each finding in this Order which deals with the overall level of rate base, revenues, and expenses for North Carolina retail cost of service has been determined in a manner reflective of that nuclear capacity factor.

Louisiana Energy Services

12. Duke, through a subsidiary, has a 29% interest in Louisiana Energy Services (LES), a partnership formed to develop a uranium enrichment facility.

13. Duke is committed to expend $8.3 million on behalf of the LES project, and Duke expects to incur an additional $962 thousand internally on the project. Duke proposes to amortize the expenditures as research and development expenses.

14. The LES project is a nonutility venture with characteristics quite different from either Duke's public utility operations or traditional utility research and development. LES should be funded by Duke's shareholders.

DSM Stipulation

15. The Public Staff and the Company entered into a Stipulation relating to Demand-Side Management (DSM) cost recovery. The Stipulation should be approved for this proceeding.

16. The Company should, on January 1, 1992, begin utilization of the Demand-Side Management cost deferral mechanism as stipulated to by Duke and the Public Staff and filed with this Commission on September 9, 1991, in Docket Nos. E-100, Sub 58, and E-7, Sub 487.

17. The appropriate North Carolina Retail Demand Factor to be utilized in calculating the ¢/kWh Credit as shown on Appendix A of the September 9, 1991, Stipulation agreement is 61.7443%.

18. The appropriate level of North Carolina Retail mWh sales to be utilized in calculating the ¢/kWh Credit as shown on Appendix A of the September 9, 1991, Stipulation agreement is 40,596,669 mWh.

19. The appropriate level of incremental DSM costs to be included in rates is $14,038,798 on a total-company basis ($8,668,000 North Carolina retail).

20. Duke should be required to file quarterly reports showing the status of and the activity in the DSM deferred account established herein.

Conservation/Load Management

21. The Company's efforts regarding its conservation and load management (CLM) programs are both sound and reasonable.

22. The Company should continue to explore enhancements to its existing CLM programs and identify new cost-effective programs in an effort to cancel or delay the need for future supply-side resources.

23. The Company should no longer collect funds from its residential customers for the Residential Loan Assistance Program (RLAP). The Company should report to the Commission on the need for resuming funding of the Residential Loan Assistance Program account at such time as the Company determines the need for such resumed funding.

24. The Company should be allowed to fund other residential DSM programs out of the Residential Loan Assistance Program account, provided it first obtains Commission approval of specific uses of funds from the account.

25. The Company should include the Residential Loan Assistance Program in future analyses of its Least Cost Integrated Resource Plan (LCIRP) for evaluation as a DSM resource option.

Depreciation Rates

26. The correct Iowa curve and projection life for Account 354.00, Transmission-Towers and Fixtures, for purposes of this proceeding are R4 and 40 years, respectively.

27. The correct Iowa curve and projection life for Account 356.00, Transmission-Overhead Conductors and Devices, for purposes of this proceeding are R3 and 35 years, respectively.

28. The correct composite depreciation rate to be used for the Transmission Plant Category is 2.57%.

29. The correct Iowa Curve and projection life for Account 364.00, Distribution-Poles, Towers, and Fixtures, for purposes of this proceeding are R2 and 30 years, respectively.

30. The correct Iowa Curve and projection life for Account 367.00, Distribution-Underground Conductors, for purposes of this proceeding are S1.5 and 30 years, respectively.

31. The correct Iowa Curve and projection life for Account 368.00, Distribution-Line Transformers, for purposes of this proceeding are R3 and 30 years, respectively.

32. The correct Iowa Curve and projection life for Account 369.00, Distribution-Devices, for purposes of this proceeding are L0.5 and 30 years, respectively.

33. The correct Iowa Curve and projection life for Account 370.00, Distribution-Meters, for purposes of this proceeding are R1 and 30 years, respectively.

34. The correct composite depreciation rate to be used for the Distribution Plant Category is 3.59%.

35. The correct future net salvage rate and depreciation rate for Account 392.13, General Plant-Heavy Trucks, for purposes of this proceeding are 20.0% and 4.77%, respectively.

36. The correct future net salvage rate and depreciation rate for Account 392.18, General Plant-Trailers, for purposes of this proceeding are 50.0% and 1.63%, respectively.

37. The correct future net salvage rate and depreciation rate for Account 394.50, General Plant-Tools, Shop and Garage (Construction), for purposes of this proceeding are 0.0% and 5.80%, respectively.

38. The correct future net salvage rate and depreciation rate for Account 396.50, General Plant-Power Op (Excavators and Cranes), for purposes of this proceeding are 25.0% and 0.21%, respectively.

39. The appropriate depreciation rates for purposes of setting depreciation expense in this proceeding are as follows:

Function	Rate
Production	
Steam	2.57%
Nuclear	
Decommissioning	1.61%
Investment	3.09%
Total Nuclear	4.70%
Hydraulic	1.98%
Other	0.74%
Transmission	2.57%
Distribution	3.59%
General (Summary only)	3.59%

40. The appropriate components of decommissioning expense to be included in cost of service are as follows:

(000's Omitted)

Unit	Total Cost	Annual Cost System	Annual Cost N.C. Retail
Oconee 1	$164,792	$10,491	$ 6,478
Oconee 2	158,311	10,101	6,237
Oconee 3	202,855	12,218	7,544
Oconee ISFSI	21,750	1,325	818
McGuire 1	171,246	8,950	5,526
McGuire 2	186,265	9,294	5,739
Catawba 1	23,476	1,199	740
Catawba 2	26,163	1,271	785
Total	$954,858	$54,849	$33,867

Fuel Procurement

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

Fuel Factor

42. The test period per book system sales are 66,761,941 mWh.

43. The test period per book system generation is 71,203,560 mWh and is broken down by type as follows:

	mWh
Coal	27,262,577
Oil & Gas	52,986
Light Off	
Nuclear	32,913,871
Hydro	2,182,186
Net Pumped Storage	(303,576)
Purchased Power	672,972
Interchange in	529,894
Interchange out	(1,083,994)
Catawba Contract Purchases	8,657,403
Catawba Interconnection Agreements	299,820
Interchange	19,421
Total Generation	71,203,560

44. The system normalized nuclear capacity factor which is appropriate for use in this proceeding is 72% and its associated generation is 32,117,290 mWh.

45. The adjusted test period sales of 66,233,808 mWh results from an additional 511,007 mWh of customer growth, 327,012 mWh associated with weather normalization, and (1,366,152) mWh associated with the adjustment for Catawba retained generation added to test period system sales of 66,761,941 mWh.

46. The adjusted test period system generation which is appropriate for use in this proceeding is 71,428,171 mWh and is broken down by type as follows:

	mWh
Coal	29,375,177
Oil & Gas	40,184
Light Off	-
Nuclear	32,117,290
Hydro	1,859,100
Net Pumped Storage	(382,554)
Purchased Power	672,972
Interchange in	529,894
Interchange out	(1,083,994)
Catawba Contract Purchases	8,300,102
Total Generation	71,428,171

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

A. The coal fuel price is $17.21/mWh.
B. The oil and gas fuel price is $72.90/mWh.
C. The Light Off fuel expense is $4,222,000.
D. The nuclear fuel price is $5.57/mWh.
E. The purchased power fuel price is $13.41/mWh.
F. The interchange in fuel price is $25.76/mWh.

G. The interchange out fuel price is $17.51/mWh.
H. The Catawba Contract Purchase fuel price is $5.80/mWh.

48. The adjusted test period system fuel expense which is appropriate for use in this proceeding is $730,721,000.

49. The proper fuel factor for this proceeding is 1.1032¢/kWh excluding gross receipts tax.

Materials and Supplies

50. For purposes of this proceeding, accounts payable related to construction materials and supplies in the amount of $4,775,000 should be deducted from working capital.

51. The appropriate level of materials and supplies for use in this proceeding is $172,358,000.

Working Capital Allowance

52. The appropriate level of required bank balances to be included in the working capital investment is $1,750,000.

53. The appropriate level of bond reacquisition premiums to be included in the working capital investment is $26,647,000.

54. The assignment of 137.50 lag days to interest on customer deposits is appropriate in this proceeding.

55. The assignment of 53.30 and 48.61 lag days to the total amount of current federal and state income taxes, respectively, is appropriate in this proceeding.

56. The assignment of 85.80 and 45.63 lag days to interest and preferred dividends, respectively, is appropriate in this proceeding.

57. The appropriate level of investor funds advanced for operations to be included in the working capital investment is $82,954,000.

58. The unamortized investment in the abandoned Coley Creek project of $3,866,000 should not be included in rate base.

59. For purposes of this proceeding, it is appropriate to reduce the unamortized balance of 1989 storm damage costs by $1,404,000 and to reduce the related accumulated deferred income taxes by $537,000. It is also appropriate to reduce the annual amortization of these costs by $386,000 in order to remove regular straight-time payroll from these costs.

60. The appropriate level of miscellaneous deferred debits to be included in the working capital investment is $28,926,000.

61. The appropriate level of customer deposits to be deducted from the working capital investment is $10,150,000.

62. The appropriate level of cash working capital investment for use in this proceeding is $130,127,000.

Bad Creek Hydroelectric Station

63. All four units of the Bad Creek Hydroelectric Station were in commercial operation prior to the close of hearing. These units add 1,065 MW of capacity to the Duke system.

64. The Bad Creek Hydroelectric Station was completed at a reasonable and prudent cost under Duke's budget.

65. The Bad Creek Hydroelectric Station is needed to enable Duke to meet the load on its system and to maintain a minimum level of reserve requirements.

66. The Bad Creek Hydroelectric Station is used and useful and the costs of the station should be included in Duke's rate base.

Rate Base

67. The appropriate level of electric plant in service for use in this proceeding is $8,337,371,000.

68. The appropriate level of accumulated depreciation for use in this proceeding is $3,226,413,000.

69. It is inappropriate to increase accumulated deferred income taxes to reflect the inclusion in cost of service of the Bad Creek Pumped Storage Facility.

70. The appropriate amount of accumulated deferred income taxes for use in this proceeding is $813,344,000.

71. The appropriate amount of operating reserves for use in this proceeding is $34,076,000.

72. Duke's reasonable original cost rate base used and useful in providing service to its North Carolina retail customers is $4,566,023,000, consisting of electric plant in service (including nuclear fuel) of $8,337,371,000, materials and supplies of $172,358,000, and working capital investment of $130,127,000, reduced by accumulated depreciation and amortization of $3,226,413,000, accumulated deferred income taxes of $813,344,000, and operating reserves of $34,076,000.

Test Period Revenues

73. The appropriate level of unadjusted kWh sales for the North Carolina retail jurisdiction is 40,160,745,361 kWh.

74. The appropriate adjustments to sales and revenues due to normal weather for the North Carolina retail jurisdiction are 144,405,000 kWh and $11,877,000, respectively.

75. The appropriate adjustments to sales and revenues due to customer growth for the North Carolina retail jurisdiction are 291,517,887 kWh and $20,223,135, respectively; and the appropriate adjustment to system sales for customer growth is 511,006,501 kWh.

76. The appropriate level of adjusted kWh sales for the North Carolina retail jurisdiction is 40,596,669,000 kWh.

77. No recession adjustment to test period sales is appropriate.

78. The appropriate level of pro forma end-of-period revenues under present rates is $2,412,417,000.

Schedule J

79. Duke has a contract (Schedule J) with Carolina Power & Light Company to sell CP&L 400 megawatts of capacity beginning January 1, 1992. On September 5, 1991, CP&L notified Duke that it does not intend to carry through with the purchase. A dispute exists between Duke and CP&L over Schedule J and litigation may result. In light of the present uncertainty as to the Schedule J transaction, no adjustment to test period revenues to reflect Schedule J sales is appropriate. However, it is appropriate for Duke to place all proceeds - whether payments, damages or settlement - received as a result of Schedule J in a deferred account as herin after provided.

Operating Revenue Deductions

80. The appropriate level of North Carolina retail fuel expense for use in this proceeding is $450,106,000.

81. It is appropriate to adjust Catawba purchased capacity expense to reflect the rate of return approved herein and the methodology employed by the Company.

82. It is appropriate to levelize Catawba purchased capacity payments pursuant to the Catawba Interconnection Agreements with North Carolina Municipal Power Agency, North Carolina Electric Membership Corporation, Saluda River Electric Cooperative, Inc. and Piedmont Municipal Power Agency over a 15-year period.

83. It is appropriate to reduce Catawba purchased energy expense by $4,460,000 to achieve parity between system costs and the jurisdictional allocation factors utilized in this proceeding.

84. It is appropriate to increase purchased power and net interchange expense by $6,523,000 to recognize the implementation of the Nantahala/Tennessee Valley Authority purchased power agreement.

85. The appropriate level of purchased power and net interchange expense for use in this proceeding is $249,412,000.

86. The Public Staff adjustment to operation and maintenance expenses to alter the percentage used to allocate the test year payroll adjustment to expense is reasonable for purposes of this proceeding. This adjustment also results in a related adjustment to general taxes.

87. The Public Staff adjustment of $(2,332,000) to eliminate the residual portion of the Company's proposed post-test year attrition adjustment is reasonable for purposes of this proceeding.

88. The Public Staff adjustment to exclude $413,000 from operation and maintenance expenses, representing 50% of the North Carolina retail portion of the compensation of the officers most closely linked with meeting the demands of the Company's common stockholders is reasonable and appropriate for purposes of this proceeding.

89. It is appropriate to reduce advertising expenses by $1,135,000 in order to remove costs incurred for advertising designed to compete with other sources of power services and designed to promote the Company's image.

90. It is appropriate to reduce operations and maintenance expenses by $337,000 in order to remove 50% of the dues paid to the U.S. Council for Energy Awareness and the American Nuclear Energy Council.

91. The adjustment of $(635,000) to the North Carolina Utilities Commission regulatory fee expense is appropriate for purposes of this proceeding.

92. The adjustment of $(2,341,000) to operations and maintenance expenses to recognize cost savings experienced in 1991 is reasonable for purposes of this proceeding.

93. The Public Staff adjustment to annualize expenses is reasonable for purposes of this proceeding. This adjustment results in an increase in operations and maintenance expenses of $254,000 over the amount proposed by the Company and an increase of $28,000 in general taxes.

94. It is appropriate to reduce operations and maintenance expenses by $141,000 in order to exclude a total of 50% of the test year expenses of the Department of Public Affairs, which engages in lobbying activities. The cost of lobbying should not be charged to the Company's ratepayers.

95. Other operations and maintenance expenses should be increased by the North Carolina retail amount of $8,668,000 incremental DSM costs agreed to by the Public Staff and the Company.

96. It is appropriate to increase operations and maintenance expenses by $9,456,000 to reflect the implementation of accrual accounting for other post-employment benefits expense.

97. It is appropriate to increase operations and maintenance expenses to reflect changes in wage and salary rates occurring after the end of the test year. This adjustment also results in an upward adjustment to general taxes.

98. It is appropriate for purposes of this proceeding to update Nuclear Regulatory Commission fee expense by $6,460,000 in order to update that expense to a current level.

99. The Public Staff adjustment of $(1,606,000) to insurance expense in order to update that expense to a 1991 level is reasonable for purposes of this proceeding.

100. It is appropriate for purposes of this proceeding to include operating expenses related to the Bad Creek Pumped Storage Facility in the cost of service. This inclusion results in an increase in operations and maintenance expenses of $1,001,000, an increase in depreciation expense of $12,329,000, an increase in general taxes of $4,243,000, a decrease in income tax expense of $5,738,000, and an increase in the amortization of investment tax credits of $556,000.

101. The level of wages, benefits, and materials expenses appropriate for use in this proceeding is $669,698,000.

102. The Public Staff adjustment to reduce transmission and distribution depreciation expense for recommended depreciation rate changes is unreasonable for purposes of this proceeding. The Public Staff's method to calculate end-of-period transmission and distribution depreciation expense is appropriate.

103. The Public Staff adjustment to general plant depreciation expense due to recommended depreciation rate changes is unreasonable for purposes of this proceeding. The Public Staff's method to calculate end-of-period general plant depreciation expense is appropriate.

104. The rate of return on common equity of 13.20% approved by the Commission to set rates in Docket No. E-7, Sub 408, as utilized by the Company, should be used to determine the maximum possible recoverable level of Bad Creek deferred costs.

105. The recoverable level of Bad Creek deferred costs should not be limited to the level of earnings attrition experienced by the Company during the period those costs were deferred.

106. The recoverable level of Bad Creek deferred costs should be amortized over a three-year period using the net-of-tax overall rate of return of 9.08% approved in this proceeding.

107. The appropriate level of Bad Creek costs to be deferred in this proceeding equals $16,112,000.

108. The level of depreciation expense appropriate for use in this proceeding is $302,474,000.

109. The Public Staff adjustment of $(763,000) to the test year level of FICA tax expense is reasonable for purposes of this proceeding.

110. The level of general tax expense appropriate for use in this proceeding is $153,284,000.

111. Based on the findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is $179,646,000

112. The level of interest on customer deposits appropriate for use in this proceeding is $780,000.

113. The amortization of investment tax credits appropriate for use in this proceeding is $10,781,000.

114. The overall level of operating revenue deductions under present rates appropriate for use in this proceeding is $1,994,619,000.

Capital Structure and Rate of Return

115. It is inappropriate to remove Duke's equity investment in its subsidaries in developing the proper capital structure for purposes of this proceeding. The proper capitalization ratios for use in this proceeding are as follows:

Long-Term Debt	40.50%
Preferred Stock	9.68%
Common Equity	49.82%
Total	100.00%

116. The proper embedded cost of long-term debt is 8.60% and the proper embedded cost of preferred stock is 7.54%.

117. Estimates of the cost of common equity capital derived by use of the DCF methodology as well as the CAPM methodology are entitled to be given weight in reaching a final determination in this case.

118. The comparable earnings methodology and data, excluding the comparable companies DCF methodology, presented by the Public Staff should be given the greater weight in determining the cost of common equity capital for purposes of this proceeding.

119. The proper cost of common equity capital for purposes of this proceeding is 12.5% and includes no allowance for down markets or flotation costs.

120. Based upon the foregoing findings with respect to the proper capitalization ratios and the appropriate cost rates for each component of capital reflected in that capitalization, the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 10.44%.

Revenue Increase

121. Duke Power Company should be authorized to increase its annual level of electric operating revenue by $100,072,000. After giving effect to the approved increase, the annual revenue requirement for Duke Power is $2,512,489,000 which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

Rate Design

122. The percentage increase applied to each major rate class in this proceeding should be the same percentage for all rate classes, except for Rate Schedules GB, GT and IT.

123. The percentage increase applied to Rate Schedules GB, GT and IT in this proceeding should be two percentage points greater than the percentage increase applied to the respective alternative rate schedules.

124. Fifty percent of the proposed $4,046,000 adjustment for a revenue shortfall due to customer migration among the various rate schedules should be recovered from the rate classes responsible for the shortfall, and fifty percent should be recovered from all rate classes in proportion to the revenue requirement for each rate class.

125. The proposed $4,046,000 adjustment for a revenue shortfall due to customer migration among the various rate schedules is based on Duke's proposed revenue requirement, and should be adjusted to reflect the revenue requirement actually granted herein.

126. The revenue adjustments for customer growth and for weather normalization should be incorporated into the revenue requirement for each rate schedule as applicable.

127. The revenue adjustments for customer growth and for weather normalization are based on the present rates, and should be adjusted to reflect the rate increases granted herein.

128. The Company should continue to offer Schedule RTX, the all-energy residential time-of-use schedule, to its residential customers.

129. The Company should remove the term "experimental" and any other reference in Schedule RTX or literature discussing Schedule RTX that refers to Schedule RTX as anything other than a permanent rate offering.

130. The residential comparative billing program proposed by the Company should be modified to include Schedule RTX, but the program may still be limited to 1,000 customer volunteers on the system at a time.

131. The Company should be required to report back to the Commission within six months on its study of the feasibility of providing, in some fashion, periodic information to residential time-of-use (TOU) customers regarding the savings (or loss) for the TOU rates versus the non-TOU rates.

132. The Company should include, in addition to the six holidays proposed in its application for Schedule RT, Good Friday and the Friday after Thanksgiving as off-peak periods as well. These eight holidays should also be designated as off-peak for Schedules RTX and OPT.

133. The Company should monitor the system loads on Martin Luther King Day in order to determine if or when it should be included with other off-peak holidays, and it should address the status of its ongoing review in its next general rate case.

134. Any revenue shortfall resulting from the designation of additional off-peak holidays herein should be recovered from the rate schedules responsible for the shortfall.

135. The modified rate design proposed by the Company for Schedule OPT, including reduced number of on-peak hours during the summer months, should be adopted for this proceeding. The Company should not be required to reduce the number of on-peak hours for Schedule OPT during the winter months.

136. The Company should be required to present testimony in its next general rate case addressing the justification for and the use of the two tier billing demand ratchet in Schedule I.

137. The modified rate design proposed by the Company for Schedule GA, including the summer/winter differential, should be adopted for this proceeding.

138. The modifications proposed by the Company for Interruptible Service Rider IS should be approved, including the $3.50 per kW credit.

139. The proposed 950 kWh energy block should be merged with the proposed over 1,300 kWh energy block for the winter season in Schedules RA 1 thru 4 and RE 1 thru 2 in this proceeding.

140. The proposed 39,000 kWh energy block should be merged with the proposed 95,000 kWh energy block in the 275 kWh per kW section of Schedules G and GA in this proceeding.

141. The Company should be required to present testimony with its next general rate case discussing the cost justification for the over 90,000 kWh energy block in the 125 kWh per kW section of Schedules G, GA and I, and discussing particularly why the price level of said energy block should be lower than the price level in the energy block of the over 400 kWh per kW section of each respective rate schedule.

142. The rate designs, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company, except as modified in this Order, are appropriate and should be adopted.

Property Tax Rider

143. At the time of Duke's last general rate case, Docket No. E-7, Sub 408, Duke had an ongoing dispute with the North Carolina Department of Revenue as to the level of Duke's property taxes for 1985, the test year in that case. The Commission set rates based upon the Department of Revenue's position in that dispute, but Duke agreed to refund the excess property taxes collected in the event the dispute was ultimately determined in Duke's favor. The Commission required the Company to place certain potential excess property taxes collected in a deferred account subject to refund depending upon the outcome of the dispute.

144. Duke and the Department of Revenue reached a settlement of their dispute over the 1985 property taxes, as a result of which Duke paid $2,660,000 of the $3,429,000 of property taxes in dispute.

145. The Company should refund to its customers the excess property tax expense collected, plus interest, as provided in the Commission's Order in Docket No. E-7, Sub 408. This refund should take the form of a decrement rider in the amount of .00716¢/kWh, with the rider to be effective for one year beginning with the effective date of this Order.

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

The evidence supporting these findings of fact is contained in the verified application, the Commission files and records regarding this proceeding, the Commission's prehearing orders in this case, and the testimony of Duke's witnesses. These findings are essentially informational and are not controverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witness Lee and the public witnesses. The Commission notes that the record contains substantial testimony that Duke is providing good service and very little testimony suggesting inadequate service. A careful consideration of all the evidence bearing on this issue leads the Commission to conclude that the quality of electrical service being provided by Duke to retail customers in North Carolina is good.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 6 - 9

The evidence relating to cost allocation is found in the testimony of Company witnesses Denton, Lee, and Stimart, Public Staff witness Lam, CUCA witness Phillips, and NCIEC witness Baron.

The Company provides retail service in two states, conventional wholesale service, and service under the Catawba Agreements. It is therefore necessary to allocate the cost of service both among jurisdictions and among customer classes within each jurisdiction. The Commission has used the summer coincident peak (Summer CP) method for cost allocation in all of Duke's previous rate cases in North Carolina since 1970. The Company proposes to continue to utilize the Summer CP method for this proceeding. This method is also used by the South Carolina Public Service Commission for that jurisdiction and is the basis for cost allocation under the Catawba Agreements. Almost all of the Company's revenues are currently allocated on the basis of the Summer CP method. Continued use of the Summer CP was supported by Company witnesses Denton and Stimart, CUCA witness Phillips and NCIEC witness Baron. However, the Public Staff recommended a change in the cost allocation method, urging adoption of the Summer/Winter Peak and Average methodology (SWPA).

The Company proposed to continue to allocate demand related production and transmission costs based on summer peak demand, which involves the determination of demand for electricity that each jurisdictional rate class places on the system during the time of the system peak. Company witness Denton testified that the summer peak is the natural and dominant peak on the Duke system and that Duke's forecast shows that this situation will continue.

Witness Denton further testified that if Duke or the Commission were to diminish the price signals for electricity during the summer by changing the allocation of cost from a Summer CP method to some other method and price electricity based on the new method, the result would be an acceleration of the growth of the summer system peak, decreased off-peak winter sales, and a reduction of the Company's system load factor, all of which would ultimately increase costs to all customers.

NCIEC witness Baron also recommended continued use of the Summer CP methodology for cost allocation. Witness Baron testified that this methodology is appropriate because the Company plans its facilities to meet the dominant summer peak. He contended that the Summer CP methodology sends appropriate price signals to customers because it prices consumption during the summer peak higher than consumption during off-peak times.

CUCA witness Phillips also recommended use of the Summer CP method. Witness Phillips testified that his recommendation was based on the load characteristics of the Duke system. Witness Phillips contended that the capital costs of a base load or a peaking plant are not a function of the number of kWhs generated by the plant, but are fixed and must be recovered no matter the number of kWhs sold. He did concede, however, that the decision to add plant, whether base load or peaking, should be consistent with keeping system average costs as low as possible.

Public Staff witness Lam testified in support of a Summer/Winter Peak and Average methodology. Witness Lam testified that this method computes an allocation factor for production plant using both the summer and winter peaks, and allocates a portion of production plant to energy production based on load factor. For Duke, this method would allocate approximately 60% of production plant based on load factor. The remaining 40% of plant would be allocated by an average of the summer and winter peaks.

Witness Lam explained that he recommended the SWPA for two reasons. First, both seasonal peaks are considered in determining the availability of generating units and system capacity requirements. Duke's two seasonal peaks are typically very similar in size and must be met using the same production plant. Second, when there is a need for new capacity, the selection of the type of unit is based on the energy (kwh) requirement or the number of hours a unit must operate each year. If little energy is required, the peaking units are cost justified due to their low capital cost as compared to large base load units. If, however, much energy is needed, the lower energy cost of capital-intensive base load units makes them more desirable. While some of the production plant cost is incurred because of the one-hour summer and winter peaks, some plant cost is also incurred because of the energy or hour-use requirement of the plant.

CUCA argued that more baseload plant cost was assigned to high load factor customers under the SWPA allocation methodology than under the current Summer CP allocation methodology. Witness Lam testified that the high load factor customers were already receiving 23.5% of baseload plant energy while paying for only 18.9% of the baseload plant cost under the Summer CP methodology, and that under the SWPA methodology the high load factor customers would continue to receive 23.5% of the baseload plant energy while paying for 21.8% of that same baseload plant cost. Thus, they would be receiving more than they paid for under either methodology, according to witness Lam.

Witness Stimart testified on rebuttal that use of different allocation methods among jurisdictions would result in different allocations of rate base and cost of service among jurisdictions. This would lead to either unrecovered costs if the allocations did not assign all costs between jurisdictions, or recovery of more than the cost of service if the allocations duplicated assignment of costs among jurisdictions. Either result would be inappropriate for Duke or its customers.

The Commission concludes that it should approve the Summer CP methodology for allocating costs in this proceeding. The Summer/Winter Peak and Average methodology recommended by the Public Staff has been adopted by this Commission for many years now as appropriate for CP&L and for NC Power. Nevertheless, the Commission is of the opinion that further investigation is needed before such a step is taken regarding Duke Power. Accordingly, Duke should present testimony with its next general rate case to discuss the ratemaking, contractual and societal consequences of moving from the Summer CP methodology to the Summer/Winter Peak and Average methodology.

Witness Turner also testified that the cost allocation studies prepared for this proceeding are based on the cost of providing service to rate schedules R, RW, RA and RC. These customer groups are not the same as the revised customer groups proposed by Duke in this proceeding. Witness Turner pointed out that the cost allocation studies will need to be revised in order to reflect the new rate schedules or customer groups proposed by Duke.

The Commission concludes that the Company should be required to revise its future cost allocation studies in order to reflect a separate rate of return for each of the major rate schedules adopted herein. The Commission further concludes, as an administrative matter, that the Company should be required to present cost allocation studies with its next general rate case which utilize the following methodologies: (1) Summer Coincident Peak; and (2) Summer/Winter Peak and Average.

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

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Stimart and Public Staff witnesses Maness and Lam, and in the final positions of the Company and Public Staff filed on October 2 and October 4, 1991, respectively.

Public Staff witness Maness testified that the costs of the buyback of Catawba capacity and energy are not currently expected to decrease at a rate as great as was projected in 1986, when rates were set in the Company's last general rate case (Docket No. E-7, Sub 408). A major cause of this phenomenon is a restriction included in the Cooperative Catawba Buyers' Interconnection Agreements regarding the level of Catawba capacity retained by the Buyers each year. The Agreements essentially provide that each Cooperative Buyer's Retained Capacity cannot exceed 40% of its highest previously recorded demand at the hour of Duke's annual system peak as calculated under the contracts. The Cooperative Buyers' demands are not increasing at a rate fast enough to enable the Company to escape the effects of this 40% restriction. Witness Maness testified that the Company included the impact of the 40% restriction in its calculation of levelized Catawba purchased capacity expenses, resulting in a higher level of such expenses, but did not include the impact of the restriction in its calculation of the allocation factors used to allocate system costs to N.C. retail jurisdictional levels.

Witness Maness testified that there is a direct relationship between the levels of purchased capacity and energy expenses as set in the cost of service and the jurisdictional allocation factors. It has been the Commission's practice in the past to maintain parity between system purchased capacity and energy costs and the allocation factors by setting each at a level which reflects an equivalent level of Retained Capacity and Energy. However, because of the Company's failure to reflect the 40% limitation in its calculation of the allocation factors, its cost of service as initially filed in this proceeding fails to maintain this parity. Witness Maness testified that he corrected this mismatch by adjusting the demand and energy allocation factors to reflect the impact of the 40% limitation.

As noted on Stimart Rebuttal Exhibit 1, the Company did not contest the Public Staff's adjustments to allocation factors for Catawba capacity purchases. In fact, in its revised cost of service study filed as Stimart Rebuttal Exhibit 2 and in its final position filed on October 2, 1991, the Company utilized a jurisdictional allocation study which reflected the impact of the 40% limitation.

Based upon the evidence presented in this proceeding, the Commission concludes that it is reasonable and appropriate to adjust the jurisdictional cost of service study utilized in this proceeding to reflect the 40% restriction on Catawba Retained Capacity and Energy resulting from the Interconnection Agreements, as recommended by the Public Staff. This adjustment achieves the benefit of maintaining parity between the treatment of Catawba Retained Capacity and Energy in setting system costs and in setting jurisdictional allocation factors.

In its revised cost of service study filed in Stimart Rebuttal Exhibit 2 and in its final position filed on October 2, 1991, the Company also calculated jurisdictional allocation factors on the basis of a 72.0% nuclear capacity factor, the capacity factor recommended by the Company for the determination of fuel expense. In its final position filed on October 4, 1991, the Public Staff calculated jurisdictional allocation factors on the basis of a 68.82% nuclear capacity factor, the capacity factor it recommends for the determination of fuel expense. Thus, the final position of both the Company and the Public Staff is that the nuclear capacity factor used to determine fuel expense in this proceeding should also be used in the calculation of jurisdictional allocation factors. The Commission concludes that this matching is appropriate. Therefore, consistent with its finding elsewhere herein that 72.0% is an appropriate nuclear capacity factor for use in calculating fuel expense in this proceeding, the Commission finds that a nuclear capacity factor of 72.0% should be used in the calculation of the jurisdictional allocation factors to be utilized in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12 - 14

These findings of fact are based on the testimony of Company witnesses Lee and Stimart and Public Staff witness Maness.

Louisiana Energy Services (LES) is a partnership composed of Claiborne Energy Services, Inc., a Duke subsidiary, and four other entities. Duke has a 29% interest in the partnership. LES was formed to develop a uranium enrichment facility in Homer, Louisiana. Duke is committed to expend $8.3 million on behalf of the project, and Duke expects to incur an additional $962 thousand internally on the project, for a total expected expenditure of approximately $9.2 million. For ratemaking purposes, Duke is treating LES as a research and development project. The Company proposes to amortize the $9.2 million over three years, and one year of the amortization is included in test year expenses. The Public Staff, on the other hand, recommends that the expenditures already made be included in rate base and that the net LES investment be amortized over a reasonable period beginning with the first general rate case Order subsequent to commercial operation of the LES facility. The Public Staff would cap the amount to be reflected in rates at $9.2 million. In their proposed orders, both the Attorney General and CUCA propose that no ratemaking treatment be allowed and that the Company shareholders alone bear the costs, and receive any profits, of the project.

Company witness Lee testified that the objective of LES is to utilize an enrichment technology which has not previously been used in the United States in order to create domestic competition in the uranium enrichment services market and lower the price of nuclear fuel. Currently, the only domestic supplier of uranium enrichment services is the Department of Energy. LES has filed an application with the Nuclear Regulatory Commission for a construction and operating permit, and has already begun marketing efforts. After the permit is obtained, the partnership will decide whether financing can be arranged and whether construction should proceed. Witness Lee testified that Duke will receive a favorable uranium enrichment services contract, which will benefit ratepayers, if the project is completed. He testified that the potential competition from the project has already caused the Department of Energy to announce a price reduction. Witness Lee conceded that Duke had stated during discovery that a direct cause and effect relationship between LES and the price reduction could not be proven and he conceded that DOE has foreign competition, but he testified that he was satisfied that there was a relationship between LES and the price reduction. Witness Lee testified that Duke would prefer to sell its share in LES before construction but that it would consider continuing with the project if its participation was needed to make financing feasible.

Public Staff witness Maness testified that Public Staff engineering considers LES a feasible project that could possibly result in lower nuclear fuel costs and that, therefore, a certain level of expenditures for LES could be considered appropriate. However, he testified that ratepayers should for the most part be protected from the risks of the project. Witness Maness testified that the $9.2 million is an appropriate utility expenditure but that any further expenditure should be considered an outside investment in a non-utility business venture and not passed along in any manner to ratepayers. Witness Maness characterized his recommendation as a "balancing" since the ultimate success or failure of the project is unknown. He recommended that "no less than the $9.2 million be recoverable from the ratepayers whether the project succeeds or fails." If Duke sells its interest in LES for a profit, witness Maness testified that the ratepayers would be entitled to a share of the profit. Witness Maness also testified that the LES project "is not a part of Duke's core utility business. This is essentially a non-utility project," and he testified that ratemaking treatment amounts to an involuntary investment from the standpoint of an individual ratepayer who might not wish to participate in LES.

In rebuttal, Duke witness Stimart testified that Duke considers LES a core utility business. He testified that the Public Staff's recommendation is contrary to the nature of the LES expenditures as research and development costs. Other research and development costs are treated as current costs of utility operations. Witness Stimart also objected to putting a cap on the level of LES expenditures to be given ratemaking treatment regardless of whether further expenditures are prudent. He testified that the Public Staff's proposal "places the risk of LES on the Company and the reward with Duke's customers."

The Commission commends Duke for its efforts to create domestic competition in the uranium enrichment services market. The Public Staff considers the LES project to be feasible, and the Commission regards it as an appropriate and worthy effort. In this case, however, the Commission must consider its role as regulator. The LES project, desirable as it is, is not a core utility project. It is a nonutility venture that poses risks quite different from those of Duke's public utility operations. Further, many of the costs are in the nature of start-up costs for a new business, rather than the experimental or exploratory costs usually associated with utility research and development. The Commission, as regulator, must consider the appropriate role of the ratepayer with respect to this project. The Commission appreciates the Public Staff's desire to give some ratepayer support to the project while protecting the ratepayer from the risks. However, the Public Staff position suffers from its inconsistency. Given that the LES project presents characteristics different from public utility functions, the Commission believes that it should be funded by shareholders, who invest voluntarily, rather than through ratepayer dollars. Our approach leaves the costs and the risks, but also the profits that will flow from success, with the Company and its shareholders.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence relating to the Demand-Side Management (DSM) Stipulation is contained in the testimony of Company witnesses Stimart and Denton, Public Staff witnesses Maness and McLawhorn, NCIEC witness Baron, and SELC witness Coakley.

The Commission established Docket No. E-100, Sub 58 to consider least cost integrated resource planning for North Carolina utilities. The Commission's Order Adopting Least Cost Integrated Resource Plans dated May 17, 1990, approved the plan presented by Duke. Witness Denton testified that as a result of the May 17, 1990, Order, the Company began making expenditures to expand DSM planning to meet the terms of the January 5, 1990, Stipulation Agreement with the Public Staff and the May 17, 1990, Order. These increased expenditures are included in the cost of service in this case. Witness Stimart testified that test year expenses were adjusted to reflect incremental operating expenses for expansion of DSM programs. The Company's filing included an increase in N.C. retail costs of $14,620,000 related to the DSM programs included in the Company's least cost plan. Public Staff witness McLawhorn proposed to reduce this amount to $8,853,000, based on the Public Staff proposed allocation factors. Witness McLawhorn's proposal would include in rates in this case only the 1991 level of costs. Witness Stimart testified on rebuttal that the Company would not oppose witness McLawhorn's adjustment if the Stipulation between the Public Staff and the Company is approved in this proceeding, and if Duke is authorized to begin deferring DSM expenditures.

The Stipulation submitted to the Commission for approval is the result of negotiation between Duke and the Public Staff to reach agreement on a cost recovery plan for DSM expenditures necessary to implement the Company's approved least cost plan. There are three areas of cost recovery raised by Duke in its testimony and covered in the Stipulation. First, the costs associated with analysis, design, implementation and evaluation of DSM options. Second, recovery of fixed costs associated with kilowatt-hours saved through conservation measures; and third, providing an earnings incentive for successfully developing LCIRP plans that advance DSM option implementation. Only the first area, DSM program costs, is fully resolved by the Stipulation.

The Stipulation provides that beginning on January 1, 1992, the Commission would allow the Company to defer certain DSM program costs that have been formally approved by the Commission in conjunction with the Company's least cost integrated resource planning process. The costs to be deferred are load control credits, interruptible service credits, incentive payments, standby generator payments, and certain advertising costs. The Stipulation provides further that at the time the Company seeks approval of new or modified DSM programs, the Company will enumerate the nature of the costs to be deferred as part of obtaining Commission approval. Duke and the Public Staff also agreed that as an offset, the Company will credit the deferral account for the corresponding DSM costs recovered in rates from customers. The costs recovered from ratepayers would be calculated on a ¢/kwh basis times actual kwh sales. As reflected in an equation shown as an Appendix to the Stipulation, the cost recovery factor can be derived by inserting Commission approved amounts for the North Carolina retail demand factor and North Carolina retail mWh sales.

The Stipulation also provides that if Duke seeks recovery of revenue losses when it seeks Commission approval to implement a DSM program, the burden shall be on Duke to show a net revenue loss from the program. In determining the net revenue loss, Duke will offset any revenue losses with "found" sales revenues, not previously used to offset other losses, attributable to its load balancing (e.g., valley filling) programs. The Commission would approve an estimate of lost sales revenues, if any, before the program is implemented.

Finally, Duke and the Public Staff agreed that at the time incentive rewards are recognized by the Commission, the amount of such rewards will be added to the deferral account balance.

NCIEC witness Baron expressed his views on the three areas of cost recovery raised by Duke. He expressed opposition to incentives or rewards for engaging in least cost planning and opposed recovery of lost revenues associated with conservation unless the offsetting increase in revenues associated with sales growth is also considered. He supported the concept of deferral accounting and recovery of incremental DSM expenses in subsequent rate proceedings.

SELC witness Coakley testified that no specific incentive plan should be approved in this proceeding. She also testified that the DSM programs of Duke should be consistent with the principles contained in the collaborative process in Massachusetts, Vermont and Connecticutt, and she recommended adoption of several specific DSM principles.

CUCA opposes the use of a deferred account as a mechanism for capturing DSM costs. CUCA contends that the mechanism constitutes a highly favorable ratemaking treatment for DSM costs. It contends that not all DSM programs are necessarily beneficial, so not all DSM programs should have access to such favorable ratemaking treatment. CUCA also rejects the argument that the existing regulatory structure is tilted toward supply-side options and needs to be corrected in the direction of demand-side options.

Duke and the Public Staff have submitted their Stipulation to the Commission for approval in this docket and in the least cost planning docket. The Commission has carefully reviewed the Stipulation and the testimony of the parties concerning the need for cost recovery to implement DSM programs. The Commission concludes that the Stipulation is reasonable and should be approved. The Commission authorizes deferral accounting as requested in the Stipulation, but does not, in this Order, address rewards or recovery of lost revenues. These matters should be specifically addressed in other proceedings where a specific reward is being considered or where specific recovery of lost revenues is requested. The Company shall utilize Account No. 186, miscellaneous deferred debits, for the net deferral of the stipulated DSM costs. The Company will calculate a carrying cost on the net deferral based on the approved rate of return. The stipulated credit to the deferral shall be at the rate per/kwh of North Carolina retail billed kwh which reflects the approved demand factor and the approved North Carolina retail kWh base.

Other recommendations made in this case, such as those by SELC, with respect to various DSM principles and programs are, to the extent not dealt with herein, more appropriately considered in either the current Docket E-100, Sub 58, or future dockets on least cost integrated resource planning.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence concerning this finding of fact is found in the testimony of Company witness Denton and Public Staff witness McLawhorn. Witness Denton recommended that the Commission adopt the Demand-Side Management cost deferral and incentive mechanism as proposed by Duke as modified and jointly stipulated to by Duke and the Public Staff and filed with this Commission on September 9, 1991. Witness McLawhorn also urged adoption of this proposal in order to allow more accurate tracking of DSM-related costs beginning in calendar year 1992.

The Commission recognizes the need for a cost-recovery and incentive mechanism for recovery of DSM expenditures if DSM programs are truly to compete head-to-head with supply-side resources. The Commission, therefore, concludes that the modified proposal submitted by Duke and jointly stipulated to by Duke and the Public Staff in this docket should be approved and be utilized for the Company's DSM programs beginning January 1, 1992, as delineated in the Stipulation agreement. The Commission also notes that there is relatively little experience with these DSM cost-recovery mechanisms, and, therefore, reserves the right to modify them in future proceedings if necessary.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 17 - 18

The evidence supporting these findings of fact is found in the testimony and exhibits of Public Staff witness Turner and Company witnesses Denton and Stimart, and is part of the September 9, 1991, Stipulation. The Stipulation called for certain amounts and factors to be used in calculating the cents/kWh credit to be used as an offset to the cost recovery account established for DSM expenditures. Based on the language of the Stipulation and the Evidence and Conclusions contained elsewhere herein, the Commission concludes that the appropriate North Carolina retail demand allocation factor to be utilized in the calculation is 61.7443%, and the appropriate level of North Carolina retail sales to be used in the calculation is 40,596,669 mWh.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19 AND 20

The evidence supporting these findings of fact is found in the testimony of Company witness Denton and Public Staff witness McLawhorn. Witness McLawhorn stated that the appropriate level of incremental DSM costs to be included in base rates in this case is $14,038,798 on a total company basis as compared to the Company's prefiled amount of $23,502,000 total company. Witness McLawhorn stated that his figure represented 1991 costs as opposed to the Company's level which projected expenditures through 1992. He also stated that he removed inflation adjustments, incentive payment escalations, and additional staffing costs.

On cross-examination, witness Denton stated that the Company would accept the Public Staff's recommendation if the Commission approves the Company's DSM cost-recovery and incentive mechanism jointly stipulated to by Duke and the Public Staff effective January 1, 1992.

In this Order, the Commission has concluded that the stipulated DSM cost-recovery mechanism should be approved and made effective on January 1, 1992; therefore, the system level of DSM expenditures recommended by witness McLawhorn is the appropriate level of incremental DSM expenditures to be included in base rates in this case. The application of the appropriate North Carolina Retail Demand Factor results in $8,668,000 of incremental costs to be included in North Carolina retail rates.

Further, the Commission being of the opinion that good cause exists for the monitoring of the DSM program concludes that Duke should be required to file quarterly reports setting forth the status and the activity reflected in the DSM deferred account. These reports should be filed no later than 60 days from the close of each calendar quarter.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 21 - 25

The evidence for these findings of fact is found in the testimony of Company witnesses Lee and Denton and Public Staff witness McLawhorn.

The Commission concludes that Duke's efforts to date in the areas of conservation and load management (CLM) are appropriate, and that the Company should continue to explore and expand its CLM efforts in a cost-effective manner. The Commission concludes that the level of spending Duke is proposing for implementing its Least Cost Integrated Resource Plan is reasonable. The Commission believes Duke is on the right track in pursuing least-cost objectives and encourages Duke to continue to improve its least-cost planning process.

The Residential Loan Assistance Program (RLAP) is a program approved by the Commission in 1983 for the purpose of making low-interest loans to Duke's residential customers for certain energy efficiency improvements. Duke's residential ratepayers fund this program through a factor applied to residential kWh sales on all residential rate schedules. Duke places these funds in an escrow account from which it makes the loans.

Witness McLawhorn stated that the Company's Residential Loan Assistance Program currently has adequate funds in escrow to last in excess of twenty years at the rate loans were made in 1990. He further stated that, over the last five years, the fund balance has steadily increased while the balance of outstanding loans has steadily decreased. He stated that the RLAP should not be canceled, but that no additional monies should be collected from ratepayers until the Company demonstrates that additional funding is needed. He further stated that the RLAP should be included in Duke's future LCIRP analyses.

Witness Denton, under cross-examination, agreed with witness McLawhorn's assessment that the rate of funds going into the RLAP account has outpaced the funds loaned to residential customers. The Company offered as an alternative that the RLAP fund not be suspended, but that other DSM activities be funded from the RLAP account. Witness Denton indicated that the Company was studying other activities beyond residential insulation loans that might be funded from the account and proposes to seek future Commission approval for specific activities.

The Commission concludes that additional funding for the RLAP should cease at this time, but the program itself should continue to be offered to residential customers. Further, the Commission concludes that Duke should include this program in future LCIRP analyses. The Company may seek additional funding for the program in the future if necessary, but the burden shall be on the Company to demonstrate that need.

The Commission also concludes that the Company should be allowed to fund other residential DSM programs out of the RLAP account, provided it first obtains Commission approval of specific uses of funds from the account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 26 - 40

The evidence of these findings of fact is found in the testimony of Public Staff witness McLawhorn and Company rebuttal witnesses Stimart and White. Witness Stimart, in his direct testimony, presented the results of a depreciation study conducted by Foster Associates. Witness Stimart proposed that the Company's depreciation rates be changed to the rates reflected in the study. This would result in a $31,564,000 reduction in depreciation expense. Public Staff witness McLawhorn proposed to adjust downward the proposed depreciation rates for certain transmission, distribution and general plant accounts. The proposed Company and Public Staff rates for these categories are summarized below:

	Company Proposed New Depreciation Rate	Public Staff Proposed Rate	Decrease
Transmission Accounts	2.57%	1.98%	.59%
Distribution Accounts	3.59%	3.18%	.41%
General Plant Accounts (Category two accounts)	5.68%	5.60%	.08%

Witness McLawhorn stated that his recommendations were based upon his own life analysis of certain transmission and distribution accounts in which he took exception to the Iowa curves and/or projection lives as filed in the Company's depreciation study. He stated that he used actual plant data supplied by Duke and analyzed the life characteristics of these accounts. He further stated that he compared the results of his study with industry information supplied by Duke and obtained through his own research.

On rebuttal, Duke presented the testimony of Dr. Ronald E. White and witness Stimart. Witness White, a Vice President of Foster Associates, was responsible for conducting the Company's 1990 Depreciation Study. Witness White testified concerning the procedures utilized in and the thoroughness of the depreciation study conducted for Duke Power. Witness White testified that the study had been based upon accepted statistical techniques and that the study had resulted in reasonable depreciation rates. Witness Stimart testified that included in the Company's $31,564,000 proposed reduction to depreciation expense was a net decrease of $13,760,000 related to transmission, distribution and general plant subject to the depreciation rate adjustments proposed by the Public Staff. Witness Stimart also presented industry data concerning depreciation rates for transmission, distribution and general plant for the South Atlantic utilities. As shown in this data comparison, the Public Staff's proposed transmission and distribution rates would result in the Company having the lowest transmission and distribution rates of any of the 13 South Atlantic utilities. With respect to the Company's proposed transmission rate, the Company is already recommending, as a result of the recently completed depreciation study, the lowest transmission rate of any South Atlantic utility and the Public Staff proposed to lower this rate by more than 20%. With respect to general plant, the Company's proposed rate would be the second lowest of the 13 South Atlantic utilities and the Public Staff proposed an even lower rate.

Company witness Stimart also testified that the Commission in North Carolina Power's last general rate case decided earlier this year had approved an increase in North Carolina Power's transmission and distribution rates and no change in the general plant rate. In each case, the Public Staff's proposed rates for Duke would be significantly lower than that approved by the Commission in the North Carolina Power case. Finally, witness Stimart testified that a further downward adjustment in the Company's depreciation rates is inappropriate due to industry uncertainty. Witness Stimart testified that the utility industry faces a number of uncertainties which are likely to affect the remaining lives and net salvage of existing utility plant which may affect the future recovery of utility plant investment.

The Commission has carefully considered all of the evidence on this matter and concludes that it is appropriate to adopt the Company's proposed depreciation rates. Only the transmission, distribution and general plant rates are in dispute in this proceeding. The Company has presented evidence of the thoroughness of its depreciation study. Although the Public Staff does not agree with certain of the results, the record contains no compelling evidence showing that the rates utilized by the Company are unreasonable. Furthermore, the rates proposed by the Public Staff would result in the Company generally having lower transmission, distribution and general plant rates than those of the other South Atlantic utilities. Although Public Staff witness McLawhorn testified that his proposed rates are consistent with industry data, Company witness Stimart's rebuttal testimony shows that the Public Staff's rates are not consistent with industry data. The Company has already significantly lowered its depreciation rates and there is no substantial basis for a further reduction in this case. The Commission also notes that the rates proposed by the Company are significantly lower than those recently approved by this Commission for North Carolina Power with respect to transmission and general plant and only slightly above the distribution rate approved by this Commission for North Carolina Power.

Since the Commission has concluded that the depreciation rates proposed by the Company are reasonable, the curve shapes, projection lives, future net salvage rates, and depreciation rates proposed by the Company and shown in the following table for the accounts in question are the most appropriate for purposes of this proceeding.

Account	Curve	P-Life	Rem Life	FNS %	Resv Ratio %	Depr Rate %
TRANSMISSION						
352.00	R4	40	26.59			
353.00	R3	40	27.68			
354.00	R4	40	26.54			
355.00	S1.5	36	24.78			
356.00	R3	35	22.19			
357.00	R4	50	32.74			
358.00	R3	40	26.74			
Composite			33.77	-10	43.07	2.57
DISTRIBUTION						
361.00	S3	40	29.40			
362.00	R1.5	30	20.54			
364.00	R2	30	22.74			
365.00	R1	30	23.39			
366.00	R2.5	40	33.85			
367.00	S1.5	30	24.43			
368.00	R3	30	20.04			
369.00	L0.5	30	24.61			
370.00	R1	30	23.24			
371.00	R2.5	25	18.64			
373.00	R1.5	25	17.90			
Composite			25.19	-10	29.90	3.59
GENERAL PLANT						
392.13	L3	12	8.34	20	40.77	4.77
392.18	L1.5	25	19.50	50	18.40	1.63
394.50	L3	17	14.04	0	18.90	5.80
396.50	L1.5	20	14.70	25	73.63	.21

The Company proposed in this proceeding to change its decommissioning expense for its nuclear reactors. Witness Stimart testified that in the past a .67% rate for decommissioning was included in the Company's 4% nuclear depreciation rate. The Company proposed in this proceeding to change its decommissioning expense reflected in rates based upon current studies of the expected cost of nuclear decommissioning expense. The amounts in the study are based on the prompt dismantlement method of decommissioning because the Nuclear Regulatory Commission requires total funding of the contaminated components as of the date of termination of the operating license of each unit. In order to minimize costs, Duke decided to utilize a combination of internal and external funds to fund decommissioning. The Nuclear Regulatory Commission requires external funding for decommissioning the contaminated portion of each unit. The external fund amount is based on estimates contained in the site specific studies conducted by TLG Engineering, Inc. in 1989 and 1990 for each Duke nuclear unit. The external fund will be tax qualified to the extent possible under IRS rules and guidelines. The cost of decommissioning the rest of the plant will be funded internally and accrued based on a sinking fund methodology. No party presented any testimony which challenged any of the Company's decommissioning assumptions. Therefore, the Commission approves the decommissioning expense adjustment proposed by the Company.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 41

NCUC Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, plus each time the utility's fuel procurement practices change. Procedures related to Duke's procurement of fossil and nuclear fuels were filed in Docket No. E-100, Sub 47, and remained in effect throughout the 12 months ended December 31, 1990. In addition, the Company files monthly reports of its fuel costs pursuant to NCUC Rule R8-52(a).

No party offered direct testimony contesting the Company's fuel procurement and power purchasing practices. Based upon the evidence, the Commission concludes these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42 - 49

The evidence for these findings of fact is found in the testimony of Company witness Stimart and Public Staff witnesses Lam and Turner.

Company witness Stimart testified that the test period per books system sales were 66,761,941 mWh and test period per book system generation was 71,203,560 mWh. Public Staff witness Lam accepted these levels of test period per book system sales and generation for use in his fuel computation. The test period per book generation is broken down by type as follows:

	mWh
Coal	27,262,577
Oil & Gas	52,986
Light Off	
Nuclear	32,913,871
Hydro	2,182,186
Net Pumped Storage	(303,576)
Purchased Power	672,972
Interchange in	529,894
Interchange out	(1,083,994)
Catawba Contract Purchases	8,657,403
Catawba Interconnection Agreements	299,820
Interchange	19,421
Total Generation	71,203,560

In his prefiled testimony, Witness Stimart normalized the system nuclear capacity factor to a level of 63.80%, which is the 1985-89 North American Electric Reliability Council's (NERC) 5-year nuclear capacity factor for Duke's pressurized water reactors (PWR) by size. In his rebuttal testimony, witness Stimart revised his recommended system nuclear capacity factor from 63.80% to 72% and his fuel factor from 1.1833¢/kWh to 1.0955¢/kWh. Witness Stimart testified that use of 72% was reflective of recent experience and that the prudency standard permits him to uncouple the nuclear capacity factor from the NERC 5-year standard.

Witness Lam testified that the test year system nuclear capacity factor of 72.26%, as achieved by the Company, should be normalized to 68.82%, which is an average of the Company's latest 5-year (1986-90) system nuclear capacity factor of 72.06% and the latest (1986-90) NERC 5-year nuclear capacity factor for all PWRs of 65.57%. Witness Lam stated that use of this capacity factor would reduce the extent of overcollections in fuel adjustment proceedings. Witness Lam's method of calculating the system nuclear capacity factor is similar to the method recommended to and adopted by the Commission in the latest two Duke fuel adjustment proceedings, Docket Nos. E-7, Subs 462 and 481, in which the latest NERC 5-year nuclear capacity factor for PWRs was averaged with Duke's lifetime nuclear capacity factor.

Based upon the evidence, the Commission finds that a 72% nuclear capacity factor should be utilized in this proceeding. While this is a higher capacity factor then utilized in prior fuel adjustment proceedings, this is more reflective of the Company's excellent nuclear performance during the preceding five years. The 72% nuclear capacity factor is higher than that approved in the Company's 1991 fuel proceeding. In light of the Company's continued excellent nuclear performance during 1991 and the substantial fuel overcollections achieved by Duke during this same period of time, the Commission concludes that the 72% nuclear capacity factor is appropriate for use in this proceeding.

Based upon the agreement of the Company and the Public Staff as to the appropriate per book numbers, and noting the absence of evidence presented to the contrary, the Commission concludes that the test period levels of per book sales and generation are reasonable and appropriate for use in this proceeding.

Witness Stimart's prefiled testimony adjusted total per book test period sales by (400,680) mWh. This adjustment is the sum of adjustments for weather, customer growth, and Catawba retained capacity of 327,012 mWh, 558,429 mWh, and (1,286,121) mWh, respectively. Witness Stimart's rebuttal testimony adjusted per book test period sales by (480,709) mWh to obtain his adjusted system sales of 66,281,232 mWh. The only item changed from his prefiled testimony is the Catawba retained capacity, which went from (1,286,121) mWh to (1,366,150) mWh and changed the adjusted system sales to 66,281,232 mWh. Witness Lam accepted witness Stimart's adjustment for weather. Witness Lam used Public Staff witness Turner's customer growth adjustment of 511,007 mWh and further adjusted Catawba retained to a level of (1,836,673) mWh for a total adjustment of (998,654) mWh and an adjusted system sales level of 65,763,287 mWh.

The Commission concludes that the adjustment for weather of 327,012 mWh, as presented by the Company and reviewed and accepted by the Public Staff, is reasonable and appropriate for use in this proceeding, and the adjustment for customer growth of 511,007 mWh, as presented by Public Staff witness Turner and found reasonable and appropriate by the Commission elsewhere in this Order, is reasonable and appropriate for use herein. The Commission also concludes that the level of Catawba retained of (1,366,152) mWh, associated with the system nuclear capacity factor of 72% accepted as reasonable and appropriate by the Commission, is both reasonable and appropriate for use in this proceeding.

Based on the foregoing findings and conclusions, the Commission determines that the appropriate level of adjusted test period sales to be used in this proceeding is 66,233,808 mWh.

Witness Stimart presented an adjustment to per book generation due to weather, customer growth, and a Catawba retained capacity in his rebuttal testimony based on a normalized 72% system nuclear capacity factor, to arrive at his adjusted generation level of 71,478,735 mWh.

Witness Lam presented an adjustment to per book generation due to weather, customer growth from Public Staff Witness Turner, and a November 1991 to October 1992 period Catawba retained capacity based on a 68.82% normalized system nuclear capacity factor, to arrive at his adjusted generation level of 70,926,502 mWh.

Based on the Commission's conclusion discussed elsewhere herein in regards to nuclear capacity factor, Catawba retained energy, and adjusted kWh sales, the Commission concludes that the appropriate level of adjusted total system generation to be used in the proceeding is 71,428,171 mWh. This 71,428,171 mWh is broken down by type as follows:

	mWh
Coal	29,375,177
Oil & Gas	40,184
Light Off	-
Nuclear	32,117,290
Hydro	1,859,100
Net Pumped Storage	-382,554
Purchased Power	672,972
Interchange in	529,894
Interchange out	-1,083,994
Catawba Contract Purchases	8,300,102
Total Generation	71,428,171

Witness Stimart's prefiled testimony recommended fuel prices as follows: (1) coal price of $17.05/mWh; (2) oil and gas price of $68.86/mWh; (3) light off fuel expense of $4,222,000; (4) nuclear fuel price of $5.57/mWh; (5) purchased power fuel price of $13.41/mWh; (6) interchange-in fuel price of $25.76/mWh; (7) interchange-out fuel price of $17.51/mWh; and (8) Catawba Contract purchase fuel price of $5.80/mWh. In his rebuttal testimony, Mr. Stimart updated his coal price to $17.03/mWh and oil and gas to $71.92/mWh based on a test year ending July 31, 1991.

Witness Lam accepted witness Stimart's expense and fuel prices for light-off fuel expense, nuclear fuel price, purchased power fuel price, interchange-in fuel price, interchange-out fuel price, and Catawba Contract purchase fuel price, but rejected the fuel prices for the other types of generation. Witness Lam recommended fuel prices as follows: (1) coal price of $17.21/mWh based on July 1991 burn price, and (2) oil and gas price of $72.90/mWh based on July 1991 burn price. Witness Lam made these recommendations to obtain the most up-to-date prices on these fuels and to reflect more accurately today's fuel prices. Witness Lam also explained that the use of test year prices for these two fuels would place in rates fuel prices that were first charged in March 1990 in setting rates to be billed starting in November 1991. In response to a question on the use of a single month's coal price, specifically July 1991, witness Lam explained that the burn price he utilized is actually a weighted price of coal for the last three or four months.

The Attorney General takes the position that "standard ratemaking procedures" should be followed and that test year average fossil fuel costs should be used to calculate the fuel factor.

The Commission concludes that Company fuel expense and fuel prices accepted by the Public Staff and other fuel prices recommended by the Public Staff are reasonable and appropriate for use in this proceeding for the reasons stated by the Public Staff. The Commission concludes that this determination is consistent with our decisions in prior Duke fuel adjustment proceedings.

Therefore, the Commission concludes that based upon prior findings and conclusions in this Order, adjusted test period system fuel expense of $730,721,000 and the base fuel factor of 1.1032¢/kWh, excluding gross receipts tax, as shown below, are reasonable and appropriate for use in this proceeding:

	ADJUSTED GENERATION (mWh)	FUEL PRICE $/mWh	FUEL DOLLARS (000s)
COAL	29,375,177	17.21	$505,635
IC	40,184	72.90	2,930
LIGHT OFF			4,222
NUCLEAR	32,177,290	5.57	178,893
HYDRO	1,859,100		
PUMPED STORAGE	(382,554)		
PURCHASED POWER	672,972	13.41	9,024
INTERCHANGE IN	529,894	25.76	13,650
INTERCHANGE OUT	(1,083,994)	17.51	(18,985)
CAT. CONT. PUR.	8,300,102	5.80	48,141
TOTAL	71,428,171		$743,510
LESS:			
INTERSYSTEM SALES	(759,412)		(12,789)
LINE LOSS	(4,434,951)		
SYS. mWh SALES & FUEL COST	66,233,808		$730,721
BASE FUEL FACTOR CENTS/kWh			1.1032

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 50 - 62

The evidence and conclusions supporting these findings of fact are included in the testimony and exhibits of Company witness Stimart and Public Staff witnesses Peedin and Maness. The following chart summarizes the North Carolina retail amounts recommended by the Company and the Public Staff for the components of materials and supplies and working capital allowance to include in Duke's rate base in this proceeding:

(000's Omitted)

Item	Company	Public Staff	Difference
Materials & supplies:			
Fuel stock:			
Coal	$ 53,393	$ 53,251	$ (142)
Oil	3,011	3,003	(8)
Other	120,709	121,166	457
Total materials & supplies	177,113	177,420	307
Accounts payable related to construction materials & supplies	0	(4,773)	(4,773)
Net materials and supplies	$177,113	$172,647	$ (4,466)
Working Capital Investment:			
Required bank balances	$ 5,340	$ 1,755	$(3,585)
Bond reacquisition premiums	27,471	26,719	(752)
Investor funds advanced for operations	121,533	82,954	(38,579)
Miscellaneous deferred debits	34,196	31,509	(2,687)
Customer deposits	(10,150)	(10,150)	0
Total working capital investment	$178,390	$132,787	$(45,603)

There is a difference of $4,466,000 between the level of materials and supplies recommended to be included in rate base by the Company and the Public Staff. This difference is itemized in the schedule below:

(000's Omitted)

Item	Amount
1. Allocation factor	$ 289
2. Accounts payable related to construction materials and supplies	(4,755)
3. Total	$(4,466)

Witness Peedin testified that accounts payable related to construction materials and supplies represents cost-free capital that should be deducted in determining the materials and supplies component of rate base. Witness Peedin stated that Duke included the entire balance of materials and supplies inventory in rate base as if it were financed entirely by capital supplied by its debt and equity inventors. She testified that a portion of the cost of these materials and supplies was financed by accounts payable, a form of cost-free capital provided by Duke's creditors. She stated that the portion of construction materials and supplies financed by accounts payable should be deducted in determining the materials and supplies component of rate base in order to relieve the ratepayers from the unfair burden of paying a return on capital that the creditors have supplied to the Company at no cost to the investors. She also testified that these accounts payable were not recognized in developing the expense lag days used in the lead lag study; therefore, it is necessary to make a separate adjustment to deduct from rate base the accounts payable related to construction materials and supplies. She stated that if this item of cost-free capital is not deducted from rate base, it will have the effect of building into the cost of service a capital cost which does not in fact exist. She testified that her recommended adjustment ensures that the ratepayers pay no return to investors for capital not supplied by the investors. As indicated in Stimart Rebuttal Exhibit 1, Duke did not contest this adjustment.

The Commission concludes that accounts payable related to construction materials and supplies should be deducted in determining the materials and supplies component of rate base. If these accounts payable are not deducted from rate base, Duke's ratepayers will be required to pay through electric rates debt and equity costs which do not exist. The Commission's decision to deduct accounts payable related to construction materials and supplies in determining the materials and supplies component of rate base is consistent with our prior decisions in Docket Nos. E-7, Subs 289, 314, 338, 391, and 408.

Since the Commission elsewhere in this Order has rejected the allocation factor adjustments recommended by the Public Staff, the Commission concludes that the appropriate amount of materials and supplies to include in rate base is $172,358,000.

The Company proposes a total working capital allowance of $178,390,000 and the Public Staff proposes $132,787,000.

The specific areas of disagreement and the amounts included are set forth below:

	(000's Omitted) Analysis of Differences
1. Allocations	$ 106
2. Adjustment to required bank balances	(3,590)
3. Bond Reacquisition Premiums	(824)
4. Adjustments based on lead-lag study	(38,579)
5. Adjustment to include LES expenditures	2,554
6. Adjustment to remove Coley Creek investment	(3,866)
7. Adjustment to reduce unamortized storm damage	(1,404)
Total difference	$(45,603)

The Commission has already concluded elsewhere in this Order that the allocation methodology proposed by the Company should be accepted. Therefore, no allocation adjustment is appropriate here.

The $3,590,000 adjustment to required bank balances results from witness Peedin's adjustment to exclude a portion of the end-of-period level of cash in various banks that had been included in required bank balances by Company witness Stimart.

Public Staff witness Peedin testified that Duke included in rate base the end-of-period balance of cash held in various banks. Witness Peedin stated that she included as required bank balances the compensating balance requirements of the lines of credit with banks which required Duke to maintain compensating bank balances. She also testified that she included in the working capital allowance miscellaneous special deposits and working funds which the Company must maintain in order to conduct its day-to-day operations. She testified that the total dollar amount of compensating balance requirements, working funds, and special deposits, combined with the capital requirements resulting from the lead/lag study, is the total amount of cash working capital which should be included in the working capital allowance. She stated that it is improper to include bank balances in excess of this amount in the working capital allowance. Witness Peedin's recommended required bank balances in the amount of $1,755,000 consist of compensating balance requirements of $332,000, working funds of $1,351,000, and special deposits of $72,000. These amounts are calculated using the Public Staff allocation factors. As indicated in Stimart Rebuttal Exhibit 1, Duke did not contest this adjustment, except as to the proper allocation factor.

The Commission concludes that the level of required bank balances to be included as a component of the working capital allowance should be comprised of money kept on deposit to meet the Company's compensating balance requirements related to lines of credit, working funds which the Company must maintain in order to conduct its day-to-day operations, and miscellaneous special deposits. It is improper to include bank balances in excess of this amount in the working capital allowance, because an additional cash working capital amount to enable

Duke to meet its day-to-day operating requirements is provided through the result of the lead-lag study which will subsequently be discussed in this Order. These three items, plus the capital requirement resulting from the Company's lead-lag study, comprise the total amount of cash working capital necessary to enable Duke to provide electric service to its North Carolina retail customers. The inclusion of an amount of cash working capital in rate base greater than this amount will require Duke's North Carolina retail ratepayers to pay higher rates than necessary.

Since the Commission has rejected the allocation factor adjustments recommended by the Public Staff, the Commission concludes that the appropriate amount of required bank balances to include in rate base is $1,750,000.

The third area of disagreement between the Company and the Public Staff relates to bond reacquisition premiums. Company witness Stimart testified that the appropriate level of bond reacquisition premiums to include in rate base is $27,471,000. Public Staff witness Peedin testified that the appropriate level of bond reacquisition premiums to include in rate base is $26,719,000. The difference is related to allocation factor differences and to $824,000 resulting from witness Peedin's allocation of 3% of the bond reacquisition premiums to Duke's nonelectric operations.

Public Staff witness Peedin testified that Duke paid the bond reacquisition premiums to redeem high interest rate bonds and subsequently issue lower interest rate bonds. Witness Peedin stated that witness Stimart had included 100% of the bond reacquisition premiums in rate base. Witness Peedin testified that because bonds are issued to finance all of the Company's activities, not solely its electric utility operations, a portion of the bond reacquisition premiums should be allocated to nonelectric operations. Witness Peedin testified that she made an adjustment to allocate bond reacquisition premiums to nonelectric operations because ratepayers should not have to bear the cost related to the portion of these premiums which are applicable to nonelectric operations. As indicated in Stimart Rebuttal Exhibit 1, Duke did not contest this adjustment.

The Commission concludes that it is appropriate to allocate 3% of the bond reacquisition premiums to nonelectric operations. Since Duke issues capital, including bonds, to finance all of the Company's operations, not solely its electric operations, it is appropriate to allocate a portion of the bond reacquisition premiums to nonelectric operations. For purposes of this proceeding, the Commission concludes that 3% of the bond reacquisition premiums should be allocated to nonutility operations.

Since the Commission elsewhere in this Order has rejected the allocation factor adjustments recommended by the Public Staff, the Commission concludes that the appropriate amount of bond reacquisition premiums to include in rate base is $26,647,000.

The next area of disagreement between the Company and the Public Staff relates to investor funds advanced for operations calculated by use of a lead-lag study. Company witness Stimart testified that the appropriate level of investor funds advanced for operations to include in rate base is $121,533,000. Public Staff witness Peedin testified that the appropriate level of investor funds advanced for operations to include in rate base is $82,954,000. There is a difference, of $38,579,000 between the level of investor funds advanced for operations recommended to be included in rate base by witness Stimart and the final position recommended by witness Peedin. This difference results from witness Peedin's assignment of lag days to interest on customer deposits, the federal and state income tax levelization credit, interest expense on long-term debt, and preferred dividends. The chart below summarizes the $38,579,000 difference, between the amount recommended by Company witness Stimart and the final position recommended by Public Staff witness Peedin.

(000's Omitted)

Item	Amount
Lag on interest on customer deposits	$ (288)
Lag on federal and state income tax levelization credit	(3,612)
Lag on interest and preferred dividends	(34,679)
Total	$(38,579)

The first item of difference concerns the lag days applied to interest on customer deposits. Public Staff witness Peedin testified that she applied a lag of 137.50 days to interest on customer deposits because the Company has the use of this money collected from ratepayers for this period of time prior to the time the interest is paid to the customers. Witness Peedin testified that customers begin earning interest on deposits after 90 days, and that after one year of service, the customer will receive a refund check for the deposit plus any accrued interest.

Witness Peedin testified that Duke maintains that a zero lag was applied to interest on customer deposits because the customer deposit amount plus accrued interest was deducted from rate base. Witness Peedin stated that her investigation revealed that Duke had not deducted accrued interest, but had deducted only the amount of the customer deposits. As indicated in Stimart Rebuttal Exhibit 1, Duke did not contest this adjustment.

The Commission concludes that a lag of 137.50 days applied to interest on customer deposits is appropriate in this proceeding because the Company does not pay interest on customer deposits until 137.50 days after the interest is incurred. Also, since Duke did not deduct accrued interest on customer deposits in determining rate base, it is not appropriate to assign interest on customer deposits a zero lag in the lead-lag study.

The second item of difference concerns the lag days applied to the federal and state income taxes levelization credit.

Public Staff witness Peedin applied a lag of 53.30 days to the levelization credit relating to federal income taxes and a lag of 48.61 days to the levelization credit relating to state income taxes. Witness Peedin testified that Duke divided the current federal and state income taxes into two categories, levelization credit and other. She stated that Duke applied the appropriate lags to the "other" category, but recorded the effects of the levelization credit in deferred taxes, which received a zero lag. Witness Peedin testified that both categories represent current income taxes; therefore, the total amounts of current federal and state income taxes, including the levelization credits, should receive lag days of 53.30 and 48.61, respectively. As indicated in Stimart Rebuttal Exhibit 1, Duke did not contest this adjustment.

The Commission concludes that it is proper for the levelization credit relating to federal and state income taxes to receive lag days of 53.30 and 48.61, respectively, because the levelization credit amounts represent current federal and state income taxes, not deferred income taxes.

The final difference relating to investor funds advanced for operations concerns whether lag days should be assigned to interest on long-term debt and dividends on preferred stock. Public Staff witness Peedin testified that the Company actually pays the cost of debt 85.80 days and preferred stock 45.63 days after these costs are incurred in rendering service; therefore, the Company has use of the money collected from ratepayers to pay interest and preferred dividends for a period of time prior to the payment to the bondholders and preferred stockholders, thus reducing the amount of capital that otherwise would have to be obtained from other sources. Witness Peedin testified that lags are applied to the components of net operating income to recognize the different payment characteristics of each component. She testified that interest on long-term debt and preferred dividends should be accorded the same lead-lag treatment as any other component in the cost of service that is incurred by the Company before it is paid. Public Staff witness Peedin also testified that applying lags to interest on long-term debt and preferred dividends was not a new issue before this Commission. She testified that the Commission has consistently and appropriately assigned lag days to interest and preferred dividends in Duke's previous rate cases.

Company witness Stimart assigned a zero lag to interest on long-term debt and preferred dividends. Company witness Stimart states in his rebuttal testimony that by assigning zero lag days to the entire return on invested capital the Company is recognizing that the return becomes the property of the Company's investors (its bondholders and stockholders) when service is delivered and the return is earned. Also in his rebuttal testimony, witness Stimart testified that the Public Staff's position concerning assigning lag days to interest on long-term debt and preferred dividends is consistent with the Commission's treatment of this issue in the last few Duke rate cases.

The Commission concludes that it is appropriate to assign lag days to interest and preferred dividends. Witness Stimart's argument that the entire amount of net operating income for return becomes the property of the Company's investors when earned, and that there is a 41.25 day lag (revenue lag) in the investors receiving this return, is not correct for purposes of determining the Company's working capital allowance. His testimony is correct only to the extent that it applies to the net income available for common equity component of net operating income for return. It is not correct as it applies to the portion of net operating income for return that is applicable to interest expense and preferred dividends. It is a fact that Duke collects the funds to pay interest and preferred dividends from its ratepayers prior to the time that Duke must pay interest expense to its bondholders and the preferred dividends to its preferred stockholders; therefore, it is appropriate to assign lag days to interest and preferred dividends. The common stockholders, when they invest in Duke Power Company's common stock, expect to receive a return on their investment in the Company. They are entitled to the opportunity to earn a return on their investment each day that their money is invested in the Company. The assignment of zero lag days to net income available for common equity is necessary in order to give the common equity investors the opportunity to earn a return on their investment on a daily basis, because it has the effect of including in the working capital allowance the amount of capital actually earned, but not collected at the end of the test period. The common stockholders do not, however, expect to receive a return on their investment plus a return on interest expense and preferred dividends from the time that they are received by the Company until they are paid to the Company's bondholders and preferred stockholders. It is no more appropriate to assign zero lag days to interest expense and preferred dividends than it would be to assign zero lag days to property taxes, income taxes, salaries and wages, or any other component of cost of service on which there is a lag between the incurrence of the expense and the payment of the expense. All funds collected through rates before these funds have to be paid to the appropriate payee, whether it be the Company's employees, bondholders, preferred stockholders, governmental bodies or creditors, should be treated consistently in the lead-lag study. All of these funds remain in the Company for the Company's unrestricted use from the date that they are collected until the date that they are paid. If it were appropriate to assign zero lag days to interest and preferred dividends, it would be appropriate to assign zero lag days to all other components of cost of service in the lead-lag study that are incurred before they are paid by the Company. Of course this is not the case. The failure to apply lag days to interest and preferred dividends would have the effect of overstating the Company's working capital requirement and would require the customers to pay a return on cost-free capital. Accordingly, the Commission concludes that the assignment of 85.80 and 45.63 lag days to interest and preferred dividends, respectively, is reasonable and appropriate. This decision is consistent with our prior rulings in all of Duke's previous rate cases.

Based on the foregoing, the Commission concludes that the proper level of investor funds advanced for operations for use in this proceeding is $82,954,000.

The next adjustment made by the Public Staff is its inclusion of expenditures made in support of the Louisiana Energy Services (LES) project in working capital investment. This adjustment is the result of the Public Staff's recommendation concerning the appropriate overall treatment of expenditures incurred on behalf of LES.

This adjustment has been discussed elsewhere in this Order, and the Commission has denied any ratemaking treatment for the LES costs. Therefore, the Commission concludes that the Public Staff's adjustment should be denied.

The next adjustment recommended by the Public Staff is the exclusion of the unamortized balance of the Coley Creek abandonment loss from rate base. Public Staff witness Maness testified that the Coley Creek loss consists of preliminary survey and investigation charges related to an abandoned pumped storage project. He recommended exclusion of the unamortized balance of this loss from rate base, consistent with past Commission treatment of abandonment losses. The Company indicated on Stimart Rebuttal Exhibit 1 that it was not contesting this adjustment, and presented no evidence to controvert the adjustment.

Based on the evidence presented, the Commission concludes that the unamortized investment in the abandoned Coley Creek project of $3,866,000 should not be included in rate base. The Commission has long held that there should be a sharing of abandonment losses between the ratepayers and the stockholders of a utility. Exclusion of the unamortized balance from rate base in this proceeding accomplishes a reasonable sharing of the Coley Creek loss.

The final adjustment made by the Public Staff is the exclusion of a portion of the storm damage costs related to the two major storms experienced by the Company in 1989. Public Staff witness Maness testified that the Duke system was struck by a tornado in May 1989, and by Hurricane Hugo in September 1989. The storms caused damage which cost approximately $74,000,000 to repair, $23,000,000 of which would normally be charged to operating expenses. However, in Docket No. E-7, Sub 460, the Commission issued an Order which authorized deferral accounting for these costs, including amortization of the expenses over a five-year period. Witness Maness testified that he removed 10% of the deferred costs from rate base, and made corresponding adjustments to the related amortization expense. According to witness Maness, his adjustment removes the Company's regular labor-related costs from the storm damage charges, because regular payroll is normally included in current rates. Only incremental costs not otherwise recovered in rates should be included in the deferred charges. Witness Maness testified that his adjustment represented the minimum amount that should be removed from the deferred charges. He stated that there very well may be other non-incremental costs which are not readily identifiable.

Company witness Stimart testified on rebuttal that the actual storm damage expense in the test period was only $705,000 (total system) compared to an average of $2,410,000 for the past ten years (excluding the 1989 storms). Additionally, witness Stimart testified that the amount approved for storm damage expense in the Company's last general rate case was only $1,100,000, while the average storm damage expense for the years 1986-1989 was $4,000,000 per year. Therefore, witness Stimart asserted that the Company has underrecovered its storm damage expenses since its last rate case and the Company's proposed rates in this case are based on an unusually low level of storm damage expenses. However, witness Stimart agreed during cross-examination that one cannot determine the overrecovery or underrecovery of expenses as a whole by looking at only one item. For example, the amount of Reactor Plant and Equipment Maintenance expense included in test year expenses is approximately $19,000,000 greater than the amount budgeted for that account in 1991. Witness Maness also testified that some test period costs are always higher than expected, and some are always lower than expected.

Witness Maness further testified that the costs that he was recommending be excluded are "regular payroll costs which are normally included in rates to be recovered and which, in fact, would have been incurred in 1989 whether or not Hugo and the May tornados occurred." Witness Maness also testified that there were several categories of costs which the Company incurred in the Hugo storm, including "labor, inventory costs, purchases, vehicle costs, employee expenses, [and] contractor's cost, any of which could have had a component which was already being recovered in rates." The Public Staff felt it was reasonable to identify regular payroll as the one component to disallow. Witness Maness also pointed out that despite the fact that 1989 overtime hours were less than the overtime hours in the test year used in the Company's last rate case, the Public Staff chose to not disallow any overtime costs related to the 1989 storms.

After consideration of the evidence presented, the Commission concludes that the Public Staff adjustment to reduce the 1989 storm damage deferred costs is a reasonable and appropriate one. When a deferral is allowed between rate cases, it is difficult at times to determine the level of costs which should be deferred. Ideally, costs being recovered in rates at the time should not be deferred. This difficulty is one of the reasons that the Commission included in its accounting Order in Docket No. E-7, Sub 460, as it does in all of its accounting orders, a provision which preserved the right of any party to address the ratemaking treatment of these costs in future proceedings. In considering this issue of the 1989 costs, the Commission finds that an appropriate guideline to use is whether or not the costs would have been incurred had the storms not taken place. Since regular payroll would have been incurred regardless of the storms, the Public Staff adjustment is a reasonable one. No one can identify with absolute precision exactly what level of expenses would have been incurred in 1989 if the storms had not taken place. However, it is apparent that the Public Staff adjustment is reasonable.

During cross-examination of witness Maness, the Company attempted to demonstrate that the 1989 storms diverted employees from capital projects, thus increasing the amount of incremental payroll expense incurred. It is no doubt true that employees were diverted from capital and maintenance projects to repair the extensive storm damage experienced in 1989. However, the evidence shows that many of these employees were likely diverted to capital repairs, not expense repairs. Of the $74,000,000 of storm damage costs, $51,000,000, or 69%, was capitalized. No evidence has been presented to demonstrate that more or a higher percentage of labor was expensed as a result of these storms. The Commission must, therefore, reject the Company's argument.

The Commission must also reject the Company's argument that the Public Staff adjustment should be denied because a low amount of storm damage expenses is built into the current case or was built into the prior case. The Commission agrees with the Public Staff that examination of only one item cannot demonstrate whether expenses as a whole are being underrecovered or overrecovered. Some expenses are always lower than projected, while some are higher. If the Company felt that its level of 1990 storm damages was abnormally low, it was certainly free to make a normalizing adjustment. The issue of normalization of test year expenses is completely separate from the question of costs deferred in prior years for future recovery.

The Commission concludes that it is appropriate to reduce the unamortized balance of 1989 storm damage costs by $1,404,000. Accordingly it is also appropriate to reduce the annual amortization of these costs by $386,000. The Commission notes that our conclusion is consistent with our decision in a recent general rate case of Carolina Water Service, Inc. (Docket No. W-354, Subs 74, 79, and 80), to allow for Hugo storm damages only those costs that are not normally built into current rates.

The Commission therefore concludes that the appropriate level of miscellaneous deferred debits for use in this proceeding is $28,926,000.

Both the Public Staff and the Company agree that the appropriate level of customer deposits to be deducted for the working capital allowance is $10,150,000. There being no evidence to the contrary, the Commission concludes that $10,150,000 is the appropriate amount of customer deposits to be deducted from the working capital allowance in this proceeding.

The Commission concludes that the appropriate level of materials and supplies and working capital investment for use in this proceeding is made up of the following components:

(000's Omitted)

Item	Amount
Materials & supplies:	
Coal	$ 53,393
Oil	3,011
Other	120,709
Accounts Payable	(4,755)
Total materials & supplies	$172,358
Working capital investment:	
Required bank balances	$1,750
Bond reacquisition premiums	26,647
Investor funds advanced for operations	82,954
Miscellaneous deferred debits	28,926
Customer deposits	(10,150)
Total working capital investment	$130,127

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 63 - 66

The evidence for these findings of fact is contained primarily in the testimony of Company witnesses Lee and Stimart. Witness Lee testified that the Bad Creek Hydroelectric Station is a four unit, 1,065 MW station. In his prefiled testimony, witness Lee testified that Bad Creek would be completed under budget at an approximate cost of $1.1 billion. Witness Lee testified that pumped storage offers special dynamic advantages to the Duke system that no other capacity can offer. Without Bad Creek the projected summer reserve margin in 1991 would have been well below the minimum reserve margin of 20%.

In his summary and update of his testimony, witness Lee stated that Bad Creek Units 1 and 2 went into commercial operation on May 15, 1991. Without these two units Duke's summer reserve margin would only have been 15%. Unit 3 went into commercial operation on September 3, 1991. Witness Lee also testified that Bad Creek had been completed ahead of schedule and over $100 million under budget. He stated that the completed cost of Bad Creek compares favorably to other projects completed in the time frame.

Witness Stimart, in the summary of his direct testimony, testified that the final plant cost of Bad Creek was approximately $1,008,000,000. Witness Stimart also testified on rebuttal that Bad Creek Unit 4 went into commercial operation on September 13, 1991.

None of the intervenors' witnesses challenged any aspect of Bad Creek. The only apparent challenge to any aspect of Bad Creek came in the cross-examination of Duke witness Lee. Duke witness Lee was cross-examined concerning the cost of

Bad Creek compared to the cost of a combustion turbine station. Witness Lee testified that the capacity cost of Bad Creek was higher than that of a combustion turbine station but that the energy cost was lower. Witness Lee also testified that Bad Creek was intended to serve an intermediate load rather than a peaking load, such as the load served by a combustion turbine station. Witness Lee also testified as to the unique dynamic system benefits of a pumped storage station which are not available from any other form of capacity.

Based upon witness Lee's and witness Stimart's uncontradicted testimony, the Commission finds that the Bad Creek Hydroelectric Station is used and useful and necessary for Duke to maintain minimum reserve levels. The Commission also finds that the Bad Creek Hydroelectric Station was prudently constructed and that the costs of the Bad Creek Hydroelectric Station were prudently incurred.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67 - 72

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Lee and Stimart and Public Staff witnesses Maness and Peedin, and in the final positions of the Company and the Public Staff filed on October 2 and October 4, 1991, respectively. The amounts which the Company and the Public Staff presented in their final positions as their recommendations for the Company's original cost rate base are shown in the schedule below:

(000's Omitted)

Item	Company	Public Staff	Difference
Electric plant in service, including nuclear fuel	$8,337,371	$8,360,705	$ 23,334
Accumulated depreciation and amortization	(3,226,413)	(3,232,328)	(5,915)
Net electric plant	5,110,958	5,128,377	17,419
Materials and supplies	177,113	172,647	(4,466)
Working capital investment	178,390	132,787	(45,603)
Accumulated deferred income taxes	(813,881)	(822,135)	(8,254)
Operating reserves	(34,076)	(34,269)	(193)
Total original cost rate base	$4,618,504	$4,577,407	$ (41,097)

In its Evidence and Conclusions for Findings of Fact Nos. 50-62, the Commission concluded that the appropriate level of materials and supplies for use in this proceeding is $172,358,000.

In its Evidence and Conclusions for Findings of Fact Nos. 50-62, the Commission concluded that the appropriate level of working capital investment for use in this proceeding is $130,127,000.

With regard to operating reserves, the difference of $193,000 between the Company and the Public Staff relates solely to the jurisdictional factors used to allocate system amounts to N.C. retail operations. Since the Commission elsewhere in this Order has accepted the allocation adjustments proposed by the Company, the Commission concludes that the Company recommended operating reserve amount of $(34,076,000) is appropriate for use in this proceeding.

The next area of difference between the Company and the Public Staff is electric plant in service. The difference of $23,334,000 results from the different allocation factors used by the parties. The Commission has rejected the Public Staff's proposed cost of service study for allocation purposes and therefore rejects the related adjustment to electric plant in service.

The Commission concludes that the appropriate level of electric plant in service for use in this proceeding is $8,337,371,000.

The next area of difference between the Company and the Public Staff is accumulated depreciation and amortization. The difference of $5,915,000 is in the area of jurisdictional allocations. Since the Commission has rejected the allocation factor adjustments recommended by the Public Staff, the Commission concludes that the amount of accumulated depreciation and amortization appropriate for use in this proceeding is $(3,226,413,000).

The final remaining area of difference between the Company and the Public Staff is accumulated deferred income taxes (ADIT). The difference of $8,254,000 is made up of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Reallocation of Company adjusted amount	$ 2,932
Annualization of Bad Creek ADIT	5,859
Reduction of 1989 storm damages ADIT	(537)
Total	$8,254

Item 1 is related to the SWPA allocation methodology and must be rejected for the reasons stated previously.

Item 2 reflects the Public Staff's proposal to annualize the post-in-service date deferred taxes related to the Bad Creek investment and thus deduct from rate base an amount of deferred income taxes that did not exist in the test period or at the close of the hearing. This same issue was addressed in Duke's last three general rate cases, Docket Nos. E-7, Subs 373, 391 and 408, with respect to the McGuire and Catawba Stations. In those cases, the Public Staff recommended the same adjustment and the Commission agreed with the Company that the adjustment was inappropriate. No change in the Internal Revenue Code or interpretations thereof has occurred since Duke's last two rate cases. The Internal Revenue Code provides that tax normalization must be made in compliance with requirements contained in the Code; otherwise, the Company could be in jeopardy of losing benefits associated with accelerated depreciation. Therefore, if this adjustment is allowed, there is a risk of a loss of hundreds of millions of dollars in deferred taxes. The primary reason given by the Public Staff for the Commission to change its decision in the preceding Duke cases was a contrary practice adopted by Carolina Power & Light Company (CP&L). Witness Stimart testified that Duke's situation was not comparable to CP&L because CP&L utilizes a completely different approach to updating the test period.

The Commission agrees with the Company, and, consistent with our ruling in Docket Nos. E-7, Subs 373, 391 and 408, the Commission again rejects the Public Staff's adjustment.

The final Public Staff adjustment to ADIT is its $537,000 reduction of ADIT related to deferred 1989 storm damage costs. Since the Commission has previously concluded that the Public Staff adjustment to reduce deferred storm damage costs is appropriate, it is also appropriate to reduce the related accumulated deferred income taxes.

The Commission therefore concludes that the appropriate amount of accumulated deferred income taxes for use in this proceeding is $(813,344,000).

In summary, the Commission concludes that the Company's reasonable original cost rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $4,566,023,000, made up of the following components:

(000's Omitted)

Item	Amount
Electric plant in service, including nuclear fuel	$8,337,371
Accumulated depreciation and amortization	(3,226,413)
Net electric plant	5,110,958
Materials and supplies	172,358
Working capital investment	130,127
Accumulated deferred income taxes	(813,344)
Operating reserves	(34,076)
Total original cost rate base	$4,566,023

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 73 - 78

The evidence pertaining to the appropriate level of test year gross revenue was presented by Company witness Stimart and Public Staff witnesses Maness and Turner. The Company proposed test year revenues under present rates of $2,413,699,000. The Public Staff proposed test year revenues under present rates of $2,412,305,000. The table below summarizes the differences between the Company and the Public Staff:

(000's Omitted)

	Company	Public Staff
Electric Operating Revenue	$2,413,699	$2,412,305
Difference		$ (1,394)

Analysis of Differences

1. Differences in allocation factors	$ (112)
2. Change in customer growth	(145)
3. Adjustment to fuel revenue	(1,137)
Total difference	$ (1,394)

Item 1 relates to different allocation factors. The Commission has rejected the Public Staff's position which gives rise to this difference and, therefore, rejects the related accounting adjustment.

Item 2 relates to different customer growth calculations presented by the Company and the Public Staff. The Company and the Public Staff have developed a customer level which is used to adjust revenues to an annualized level, and used regression analysis to predict the end of the test period number of customers. The Company included an adjustment to revenue in its initial filing of $20,368,000 based on 318,061 mWh additional sales due to customer growth. Public Staff witness Turner recommended a revenue adjustment of $20,223,000 based on 291,518 additional mWh sales.

The customer growth adjustments made by the Company and the Public Staff were very similar in methodology and the results were also similar. The Company did not rebut the testimony of Public Staff witness Turner on the subject of customer growth.

Based on the foregoing evidence, the Commission concludes that the adjustments to revenue and kWh sales for customer growth recommended by the Public Staff are appropriate for use in this proceeding. The Public Staff presents analysis and adjustments for all customer classes including industrial as well as a variety of curve fits in arriving at best fits for each customer class. The Company's analysis was limited to linear curve fits and did not include the industrial customer classes. The Commission finds that the Public Staff's methodology is appropriate for making these adjustments. Therefore, the Commission concludes that the appropriate customer growth adjustment to revenue and kWh sales for the North Carolina jurisdiction is $20,223,135 and 291,517,887 kWh.Because the determination of the kWh sales adjustment for the jurisdiction is an integral component of the system sales adjustment, the Commission further concludes that a system sales adjustment for growth based on the Public Staff's recommendation of 511,006,501 kWh is appropriate.

The Public Staff adjusted the test year revenue from the Company's proposed fuel revenue (1.1833¢/kwh x 1.03327) to reflect the rate actually approved in the Company's most recent fuel proceeding -- Docket No. E-7, Sub 481 (1.18069¢/kwh x 1.03327). This resulted in a decrease of $1,137,000 in electric operating revenue. The Company did not contest this adjustment. The Commission concludes that the adjustment is necessary.

The Public Staff accepted the Company's calculation of unadjusted kWh sales for the North Carolina retail jurisdiction. There being no evidence in the record of this proceeding contesting the Company's unadjusted kWh sales for the 12-month test period ending December 21, 1990, the Commission concludes that the appropriate end-of-period level of unadjusted kWh sales for the North Carolina retail jurisdiction is 40,160,745,361 kWh.

The Company and the Public Staff recommended the same adjustment to normalize the test period for weather of 144,405 mWh. Based on the evidence in the record, the Commission concludes that the appropriate level of sales and revenues related to the normal weather adjustment of 144,405,000 kWh and $11,877,000, respectively are appropriate for the North Carolina retail jurisdiction.

Based on all the foregoing, the Commission concludes that the appropriate level of adjusted North Carolina retail kWh sales for use in this proceeding is derived as follows:

Description	kWh Sales
Unadjusted kWh Sales	40,160,746,000
Normal Weather Adjustment	144,405,000
Customer Growth	291,518,000
N.C. Retail Adjusted Sales	40,596,669,000

Witness Stimart testified that the Company had examined the effects on revenues due to recessionary conditions which began in the latter part of the test year and had found that no adjustment was appropriate. Witnesses Lee and Stimart also testified that industrial sales during the test period had not been significantly affected by the recession since industrial sales were relatively flat during the test period. Furthermore, witness Siimart testified that test period sales had already been adjusted upward for both customer growth and weather normalization. Based upon this evidence, the Commission finds no basis for making an adjustment.

Based on all the foregoing, the Commission concludes that the proper level of end-of-period revenues under present rates is $2,412,417,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence for this finding of fact is found in the testimony of Duke witnesses Lee and Stimart.

Some time ago, Duke entered into a contract (hereinafter referred to as Schedule J) with Carolina Power & Light Company to sell CP&L 400 megawatts of capacity beginning January 1, 1992. The Schedule J contract was filed with FERC and hearings were held, but no decision had been issued as of the hearing in this rate case. In his supplemental testimony, Duke witness Stimart recommended an adjustment to test period revenues in order to reflect the anticipated revenues to be received from CP&L under Schedule J.

Duke witness Lee testified that subsequent to the filing of supplemental testimony, CP&L notified Duke on September 5, 1991, that it does not intend to carry through with the purchase. He testified that he expects discussions with CP&L, that he cannot tell how the dispute will be resolved, and that it is entirely possible that litigation will result. He recommended that the previously anticipated revenues from Schedule J not be reflected in this case.

Duke witness Stimart proposed that Schedule J not be reflected in the cost of service in this case and that, instead, any collections received pursuant to Schedule J be recorded in a deferred account. He testified that Duke would propose a rider to reflect the amount in the deferred account as well as future collections once the uncertainty surrounding the contract is resolved.

In its proposed order, the Public Staff recommended that a rider be implemented now to track any Schedule J proceeds that may be realized in the future. The rider decrement would be initially set at zero in this case. Alternatively, the Public Staff accepted Duke's proposal to record proceeds in a deferred account to be reflected in rates through a rider when the uncertainty is resolved. CUCA argued in its brief that Duke should be required to implement a rider to reduce rates contemporaneously with the receipt of any payments under Schedule J.

The dispute over Schedule J may require a long time before resolution. It is possible that interim orders could be entered by FERC that may or may not be consistent with the final resolution. It is possible that litigation may result; it is possible that negotiations may result. In light of all the uncertainties, the Commission is reluctant to implement any type of rider now. The deferred account proposed by Duke presents a more orderly procedure. Further, the deferred account is more consistent with past Commission practices. For example, the property tax dispute between Duke and the Department of Revenue that was ongoing at the time of the last rate case was dealt with by means of a deferred account. The Commission concludes that it would be inappropriate to include any amounts from Schedule J in the revenues used to calculate rates in this case. However, the Commission orders Duke to place all proceeds - whether payments, damages or settlement - received as a result of Schedule J in a deferred account. The deferred account shall accrue carrying costs net of tax at the then applicable allowed rate of return, and the balance shall be refunded to customers in a manner to be prescribed by further order of the Commission when the uncertainty surrounding Schedule J is resolved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80 - 114

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Stimart and Public Staff witness Maness, and in the final positions filed by the Company and the Public Staff on October 2 and October 4, 1991, respectively. The levels of operating revenue deductions proposed by the Company and the Public Staff in their final positions are set forth in the schedule below:

(000's Omitted)

Item	Company	Public Staff	Difference
Fuel used in electric generation	$ 447,271	$ 465,559	$18,288
Non-fuel purchased power and net interchange	259,272	247,399	(11,873)
Wages, benefits, materials, etc.	678,870	671,618	(7,252)
Depreciation and amortization	299,697	285,372	(14,325)
General taxes	154,230	153,596	(634)
Interest on customer deposits	780	780	0
Income taxes	173,814	176,265	2,451
Amortization of investment tax credit	(10,781)	(10,808)	(27)
Cost and Rate of Return update	44,103	0	(44,103)
Total operating revenue deductions	$2,047,256	$1,989,781	$(57,475)

As can be seen from the above schedule, the Company and the Public Staff agree on the amount to be included for interest on customer deposits. Therefore, the Commission concludes that the level of interest on customer deposits appropriate for use in this proceeding is $780,000.

The three categories of operations and maintenance expenses are fuel, purchase power and net interchange, and other O&M expenses, i.e.; wages, benefits and materials. The Commission will discuss each area separately. The differences between the Company and the Public Staff with respect to fuel used in electric generation are summarized below:

(000's Omitted)

	Company	Public Staff
Fuel Used in Electric Generation	$447,271	$465,559
Difference		$ 18,288

Analysis of Differences

1.	Difference in fuel factor and line loss	$ 18,591
2.	Difference in customer growth	$ (303)
		$ 18,288

Each proposed adjustment to fuel is related to a position or contention that has been considered by the Commission previously. Having considered the positions and proposed adjustments of the parties, the Commission concludes that $450,106,000 is the appropriate level of fuel expense for use in this proceeding.

This level of fuel expense appropriate for use in this proceeding is calculated as follows:

(000's Omitted)

Item	Amount
N.C. retail mWh sales	$40,596,669
Fuel factor	11.032
Product (000's Omitted)	$ 447,862
N.C. retail line loss differential	2,244
Fuel expense (000's Omitted)	$ 450,106

The next area of difference between the Company and the Public Staff is non-fuel purchased power and net interchange expense. The difference of $(11,873,000) is made up of the following Public Staff adjustments:

(000's)

	Item	Amount
1.	Difference in allocation factors	$ 1,341
2.	Difference in rate of return	$ (8,754)
3.	Change in Catawba non-fuel purchased energy	$ (4,460)
	Total	$(11,873)

The Commission has addressed elsewhere the reasons for the difference on Item 1 and adopts the Company's position for the reasons stated.

The Catawba purchased capacity expense portion of non-fuel purchased power and net interchange expense is impacted by the different capital structure and capital cost rates recommended by the parties. Elsewhere in this Order, the Commission addresses the issues of the proper capital structure and cost rates to be used in setting rates in this proceeding. The impact of these Commission decisions must be reflected in the Catawba purchased capacity expense. Therefore, the Commission concludes that the capital structure and cost rates approved elsewhere in this Order should be used to calculate the Catawba purchased capacity expense portion of non-fuel purchased power and net interchange expense.

The third adjustment made by the Public Staff is its $(4,460,000) adjustment to Catawba purchased energy expense. Public Staff witness Maness testified that he adjusted the energy-related N.C. retail allocation factors to reflect an increase in retained energy to the level expected to be experienced in 1992, taking into account the limitation placed on Cooperative retained capacity by the Catawba contracts. In order to maintain parity in the relationship between Catawba buyback costs and the N.C. retail allocation factors, witness Maness reduced non-fuel Catawba purchased energy expense by an amount corresponding to the adjustment to the energy allocation factors. The Company indicated, on Stimart Rebuttal Exhibit 1, that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

Based on the evidence of record, the Commission concludes that it is appropriate to reduce Catawba purchased energy expense by $4,460,000 in order to achieve parity between system costs and the jurisdictional allocation factors utilized in this proceeding.

The Commission finds that it is appropriate to adjust the levelization of Catawba purchase capacity payments to 15 years for amounts to be paid under all of the contracts with the Catawba buyers, including the Cooperative contracts. Witness Stimart testified that all of Duke's customers benefit from the sale of Catawba and not just those customers receiving service during the buy-back period. Therefore, he recommended an extension of the Cooperative levelization to 15 years, which is the last year of any purchased capacity payments to the Catawba buyers and is equal to the levelization period of the capacity payments to the Municipal owners. Public Staff witness Maness stated that the Public Staff did not oppose this change to the levelization period.

The Commission notes that the benefits of the Catawba transaction have been the subject of much consideration in prior cases. The Commission determined in those cases that the Catawba transactions benefit Duke's customers including those customers receiving service at times other than the buyback period. No party disputed any of those findings in this case. The Commission determines that it is appropriate to levelize the Cooperative purchased capacity costs over a 15 year period since future ratepayers will also receive the benefits from the sale of Catawba.

Duke witness Stimart, in his supplemental testimony, testified that Duke had entered into a contract to purchase capacity from Nantahala Power & Light Company pursuant to an interconnection agreement between Natahala and TVA. Witness Stimart stated that billings under the contract began in May 1991. Witness Stimart adjusted test period expenses by $6,523,000 to reflect purchases under this contract. Public Staff witness Maness accepted this adjustment. Therefore the Commission concludes that these expenses should be included in this proceeding.

Based on the foregoing the Commission concludes that the level of non-fuel purchased power and net interchange expense appropriate for use in this proceeding is $249,412,000.

The next area of difference between the Company and the Public Staff is wages, benefits, materials, etc. expense (other operations and maintenance expenses). The difference of $(7,252,000) is composed of the following Public Staff adjustments:

(000's Omitted)

	Item	Amount
1.	Differences in allocation factors	$ 2,257
2.	Adjustment to fuel revenue rate	(1)
3.	Disallowance of residual post test year inflation	(2,332)
4.	Disallowance of portion of officers salaries	(413)
5.	Industry dues	(674)
6.	Adjustment to regulatory fee	(635)
7.	Annualization of test period expense	254
8.	Disallowance of costs considered by Public Staff to be lobbying expenses	(141)
9.	Removal of LES amortization	(1,364)
10.	Adjustment to payroll expense	(2,597)
11.	Insurance expense	(1,606)
	Total difference	$ (7,252)

Item 1 is related to the different allocation methodogies proposed by the Public Staff and the Company. Since the Commission has adopted the Company's proposed cost allocation methodology, this adjustment must be rejected.

Item 2 is related to the Public Staff's adjustment to test year revenues to reflect the fuel revenue level established in the Company's last fuel proceeding. This adjustment increases the regulatory fee related to this level of revenues. Consistent with the Commission's determination of end-of-period revenues, the Commission concludes that this related adjustment to regulatory fee should be adopted.

Item 3 reflects the Public Staff's adjustment to exclude the residual amount of the Company's attrition adjustment to reflect annual inflation. In its initial filing, the Company proposed an attrition adjustment of $13,070,000 due to post-test period inflation. At the hearing, Witness Stimart identified certain wage increases and NRC fee increases that the Company has experienced since the application was filed. These were partially offset by $2,341,000 in cost reductions arising from the Company's cost-containment effort. These cost reductions were noted in the prefiled testimony of Public Staff witness Maness. These net cost increases were subtracted from the provision for attrition, which left a residual amount of $2,332,000. The Public Staff accepted the Company's update of wage rates and NRC fees, but proposed to disallow the residual amount. The Company did not rebut the position of the Public Staff, leaving the issue to be determined on the basis of the Public Staff's unrebutted testimony related to this proposed adjustment. Upon consideration, the Commission believes that the residual amount of the inflation adjustment should be excluded from operating revenue deductions. This decision is consistent with the Commission's treatment of this item in previous Duke Power general rate cases.

The next Public Staff adjustment is its exclusion from expenses of 50% of the compensation paid to certain of the Company's high-level officers. Public Staff witness Maness testified that he was recommending that 50% of the compensation paid by the Company to those officers whose functions are most closely linked to meeting the demands of the common stockholders be charged to those stockholders instead of the ratepayers. Witness Maness testified that since the top executives of a utility often bear a responsibility to serve the interests of the shareholders as well as the ratepayers, it is only fair that the shareholders bear a portion of the compensation of those officers. Witness Maness also testified that the Commission has adopted an adjustment consistent with his in each Duke Power, Carolina Power & Light Company, and Virginia Electric and Power general rate case since November 1984. The Company indicated, on Stimart Rebuttal Exhibit 1, that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

The Commission has given this issue much consideration not only in this proceeding but also in several other rate cases. After careful consideration, the Commission concludes that the Public Staff adjustment of $(413,000) to exclude 50% of the compensation of the officers most closely linked with meeting the demands of the common shareholders is appropriate. This adjustment is consistent with the treatment given this issue in this Company's last two general rate cases, as well as in general rate cases of Carolina Power & Light Company and Virginia Electric and Power Company.

The next Public Staff adjustment to other operations and maintenance expenses is its exclusion of dues paid to two industry organizations, the U.S. Council for Energy Awareness (USCEA) and the American Nuclear Energy Council (ANEC). Public Staff witness Maness testified that the USCEA is an organization essentially devoted to the public promotion of nuclear energy. He testified that the advertisements and brochures published by the USCEA are slanted toward the promotion of nuclear energy. The ANEC is described in the Company's E-1 filing in this case as the "advocacy voice in Washington, D.C." for "a broad cross-section of nuclear energy organizations." Witness Maness testified that he removed the dues paid to these two organizations from test year expenses because the ratepayers should not be required to fund the Company's support for organizations that promote a particular point of view on public and political issues.

Company witness Stimart testified that the Company's membership in the USCEA and the ANEC benefits the customers in many ways, including the examination of generic energy issues related to nuclear power and the collection of statistical and other information related to nuclear production. Additionally, witness Stimart testified to the importance of nuclear generation to the Company and the reliance of the Company and its customers on nuclear capacity for the reliable delivery of electricity. The Company further noted that the nuclear operating environment is continually changing from many different perspectives-legislative, regulatory, technology advance, etc. - and therefore USCEA and ANEC provide Duke with many benefits and services.

Witness Maness testified that it was not his position that these organizations engaged only in nuclear advocacy, but that their primary focus was on such advocacy. With regard to the importance of nuclear energy to the Company's operations, witness Maness testified that the basis of his adjustment is not whether nuclear power is good or bad, but that nuclear power is a controversial issue in society today, and the ratepayers should not be required to finance its public promotion. In witness Maness' view, the Company's support of these organizations essentially amounts to lobbying.

The Commission has carefully reviewed this matter. Evidence supports the Company's assertion that Duke and its ratepayers are heavily dependent on nuclear generation to meet electricity demand. Evidence was presented to support the conclusion that the ANEC and USCEA provide vital service to Duke Power, as testified to by witness Stimart. However, evidence was also presented by the Public Staff to support its contention that support of these organizations essentially amounts to lobbying. Having carefully balanced the evidence on this matter, the Commission concludes that an adjustment of $337,000 in this proceeding is appropriate. This disallowance is one-half of that recommended by the Public Staff. The Commission will continue to monitor the level of these costs in future general rate case proceedings.

The next adjustment made by the Public Staff is its reduction of expenses by $635,000 to recognize the reduction in the Commission regulatory fee from 0.12% to 0.09% of N.C. retail operating revenue, net of uncollectibles. On Stimart Rebuttal Exhibit 1, the Company indicated that it was not contesting this adjustment, and presented no evidence to controvert the testimony of Public Staff witness Maness.

The Commission concludes that it is appropriate for expenses to reflect the regulatory fee rate currently in effect. Therefore, the Commission finds the Public Staff adjustment of $(635,000) to be appropriate and reasonable in this proceeding.

The next Public Staff adjustment to other operations and maintenance expenses is its adjustment of $254,000 to annualize those expenses. Public Staff witness Maness testified that he utilized the annualization methodology which has been accepted by the Commission in the last several Duke Power rate cases. He stated that he had combined Public Staff witness Turner's recommended growth adjustments to energy-related and bill-related expenses with his recommended adjustment to payroll expenses for growth in the number of employees during the test year. Witness Maness testified that he eliminated from his adjustment certain new employees who were converted from contract status in December 1990. Since their contract labor costs were reflected in months prior to December, it would not be appropriate to also include payroll costs related to them in those months. Witness Maness further testified that his recommended methodology was more appropriate than that recommended by the Company, in that his methodology annualized separate components of expenses by factors related to those components, while the Company's methodology applied a growth factor based on only one variable, customers, to expenses related to demand, energy, and customers. On Stimart Rebuttal Exhibit 1, the Company indicated that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

The Commission has carefully considered the annualization adjustments offered by the Company and the Public Staff and concludes that the Public Staff's methodology is appropriate and consistent with Commission decisions in prior Duke Power rate cases. The Public Staff's methodology more accurately recognizes the appropriate elements included in costs associated with changes in kWh sales, customer billings, and employee levels. Since the Commission has accepted the Public Staff recommendations regarding customer growth, as set forth elsewhere in this Order, the Commission concludes that the Public Staff adjustment of $254,000 to annualize expenses is reasonable for purposes of this proceeding.

The next adjustment made by the Public Staff is its reduction of expenses by $141,000 to exclude a total of 50% of the test year expenses of the Company's Department of Public Affairs. Public Staff witness Maness testified that the job descriptions of the five key employees of this department contain many activities which exhibit characteristics of lobbying. Moreover, the basic functions of three of the employees consist of contacting public officials in order to influence the passage, defeat, or amendment of legislation of interest to the Company, while the basic function of a fourth employee also includes this objective. Witness Maness concluded that at least 50% of the Department's test year expenses should be charged to the stockholders as lobbying expenses. Since 24% of the expenses were already recorded below the line, he removed an additional 26% of these expenses. The Company indicated, on Stimart Rebuttal Exhibit 1, that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

Based on the evidence presented in this proceeding, the Commission concludes that 50% of the test year expenses of the Company's Department of Public Affairs should be excluded from operating expenses and instead should be charged to the stockholders as lobbying expenses. The cost of lobbying activities is not a proper cost of providing service to be recovered from the Company's ratepayers; therefore, the Public Staff adjustment of $(141,000) is reasonable for purposes of this proceeding.

The next adjustment made by the Public Staff is its reduction of expenses by $1,364,000 to reverse the test year amortization of Louisiana Energy Services, Inc., expenditures. As set forth elsewhere in this Order the Commission concludes that this amortization should not be allowed for ratemaking purposes. Therefore, the Commission concludes that the Public Staff adjustment of $(1,364,000) is appropriate.

The next adjustment made by the Public Staff relates to the Public Staff's reduction of wage expense by $2,597,000 to reflect a different expense percentage utilized in deriving end-of-period wage expense. The Company indicated, on Stimart Rebuttal Exhibit 1, that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

Based on the foregoing, the Commission concludes that Public Staff's methodology to derive end-of-period wage expense should be adopted and is fair and reasonable. Therefore, the Public Staff adjustment of $(2,597,000) should be accepted.

The final difference between the other operations and maintenance expenses proposed by the Public Staff and the Company relates to the Public Staff's reduction of insurance expense by $1,606,000. Public Staff witness Maness testified that he annualized property insurance expense at its 1991 level, including the 1991 level of distribution credits received by the Company. According to witness Maness, these credits have increased from 1990 levels, while premiums have remained essentially stable. The Company indicated, on Stimart Rebuttal Exhibit I, that it was not contesting the Public Staff's adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

The Commission concludes that the Public Staff adjustment of $1,606,000 to insurance expense to update that expense to a 1991 level is reasonable and appropriate for this proceeding.

In his prefiled testimony, Public Staff witness Maness proposed an adjustment to advertising expenses. Public Staff witness Maness testified that he excluded from the Company's cost of service two specific categories of advertisements:

(1) Image advertising - Advertisements designed to maintain and/or improve the Company's image.

(2) Competitive advertising - Advertisements intended to compete with the natural gas utilities and other energy services providers for additional customers and load.

Witness Maness testified that he also removed certain other expenses which provide no benefit to electric customers, including the costs of a hospitality tent and sponsorships of public television and musical events.

The Company accepted this adjustment for this proceeding only in its final position filed with the Commission. The amount of this adjustment, based on the Commission approved allocation method, is $1,135,000. There being no evidence to the contrary, the Commission concludes that other operations and maintenance expense should be reduced by the $1,135,000 spoken to above.

In Company witness Stimart's supplemental testimony he recommended an adjustment to reflect the Company's adoption of Financial Accounting Standard No. 106 - Other Post - Employment Benefits. FASB 106 provides for accrual accounting for other post-employment expenses rather than accounting on a pay-as-you-go basis. The amount recommended by the Company of $9,456,000, is based on a recent actuarial study undertaken by the Company. Public Staff witness Maness agreed with this adjustment. This adjustment is consistent with the Commission's Order in the North Carolina Power general rate case, Docket No. E-22, Sub 319, and the Commission adopts it in this proceeding.

Elsewhere in this Order, the Commission concluded that the DSM Stipulation between the Company and the Public Staff should be approved and that incremental costs of $8,668,000 should be included in rates. Therefore, the Commission concludes that other operations and maintenance expense should include $8,668,000 of incremental DSM costs for this proceeding.

The Commission has previously determined that the costs of the Bad Creek Hydroelectric Station should be included in Duke's cost of service. The level of these costs were not contested by the parties, except on the issue of allocation factor. The Commission has previously concluded that the Company's cost allocation study should be utilized in this proceeding. Therefore, the amounts proposed by the Company should be adopted in this proceeding.

Based on the foregoing, the Commission concludes that the inclusion of Bad Creek in the Company's cost of service results in an increase in operations and maintenance expenses of $1,001,000, an increase in depreciation expense of $12,329,000, an increase in general taxes of $4,243,000, a decrease in income tax expense of $5,738,000, and an increase in the amortization of investment tax credits of $556,000.

Based on the findings of fact reached herein, the Commission concludes that the level of other operations and maintenance expenses (wages, benefits, materials, etc.) appropriate for use in this proceeding is $669,698,000.

The Company proposes a depreciation and amortization expense of $299,697,000. The Public Staff would reduce this amount by $14,325,000. The differences between the Company and the Public Staff are summarized below.

(000's Omitted)

Analysis of Differences

1.	Difference in allocation factors	$ 1,290
2.	Adjustment to storm damage amortization	(386)
3.	Differences in depreciation rates and depreciation expense methodology	(9,745)
4.	Adjustment to Bad Creek deferred costs	(5,484)
	Total Difference	$ (14,325)

Item 1 relates to the different allocation methodologies proposed by the parties. Since the Commission has rejected the Public Staff's allocation methodology, this adjustment must be rejected.

Item 2 reflects the Public Staff's proposal to eliminate from the amortization of storm costs certain labor expenses. This item has already been discussed elsewhere in this Order. The Commission has already found that the Public Staff's adjustment to exclude certain labor related costs from the deferred storm damage charges is appropriate. Based on the foregoing, the Commission concludes that the Public Staff's adjustment of $386,000 to storm damage amortization should be accepted.

The next item of difference is the depreciation rates utilized for transmission, distribution and general plant, and in the methodology employed to calculate end-of-period depreciation expense based on the recommended depreciation rates. The Commission has already decided the matter of proper depreciation rates elsewhere in this Order. Based on these decisions, the Commission concludes that the Public Staff adjustment to depreciation expense for proposed changes in depreciation rates should be rejected.

The Commission has carefully reviewed the methodology employed by each party in developing end-of-period depreciation expense based on the respective recommended depreciation rates. The Public Staff methodology more closely represents the methodology employed by parties before this Commission. The Company did not rebut the methodology employed by the Public Staff. Therefore, the Commission concludes that the methodology employed by the Public Staff to determine end-of-period depreciation expense should be adopted in this proceeding.

The final item of difference relates to the amount of deferred start-up costs of the Bad Creek Hydroelectric Station. On February 7, 1991, the Company requested approval of deferral accounting of start-up costs related to the Bad Creek Hydroelectric Station during the period between commercial operation of each unit and the date of the Commission's order in this proceeding. The Commission authorized similar deferral of operation costs for McGuire Unit 2 in Docket No. E-7, Sub 373, for Catawba Unit 1 in Docket No. E-7, Sub 391 and Catawba Unit 2 in Docket No. E-7, Sub 408. Similar deferral accounting treatment has been provided for major generating plants of other utilities. The Commission entered an Order on March 6, 1991, in Docket No. E-7, Sub 484, which allowed deferral accounting, provided instructions to the Company for maintaining the deferral account, and provided that each party to this proceeding would be allowed to present evidence as to the appropriate level of expenses and fuel savings and the appropriate amortization and ratemaking treatment to be accorded these deferred items. In accordance with the Commission's instructions, the Company deferred $42,566,000 in Bad Creek start-up costs and proposes to amortize these costs in rates over three years.

Public Staff witness Maness recommended that the Company only be allowed to accrue carrying costs on the deferred dollars during the deferral period at a rate based on the rate of return adopted by the Commission in this proceeding, which witness Maness assumed would be the rate of return recommended by the Public Staff. Furthermore, witness Maness recommended that the deferred costs be recoverable only to the extent that the utility has suffered attrition based upon the allowed rate of return on common equity set in this proceeding. Attrition, according to witness Maness, would result if the utility, after pro forma adjustments, was unable to earn the return on common equity recommended by the Public Staff. Witness Maness recommended a deferral of $28,666,000 as opposed to the Company's calculation of $42,566,000. All of witness Maness' calculations were based upon a 12% allowed return on common equity.

NCIEC witness Baron proposed to adjust the amortization period for Bad Creek deferred costs from three years to fifty years. Public Staff witness Maness accepted the three year amortization period proposed by the Company.

Witness Stimart testified on rebuttal that witness Maness' adjustment was inappropriate. Witness Stimart asserted that the effect of this adjustment is to penalize a utility for bringing a plant on-line early which causes a longer deferral period before rates can be set. By bringing in a plant early, the cost of the plant is reduced as shown by the approximate $100 million reduction in Bad

Creek costs. However, under the Public Staff's proposal, the utility would be allowed to recover only a portion of the costs associated with the plant prior to the time that rates are set. Furthermore, witness Stimart testified that the Company's request was consistent with the past practices of the Commission and that the Public Staff had offered no basis for deviating from this practice. Witness Stimart also testified that witness Baron's recommendation was inconsistent with the past practices of the Commission and would only serve to increase the costs to be recovered from the customers due to the return required on the unrecovered balance.

The Commission determines that the Public Staff adjustments, spoken to above, to the level of Bad Creek costs to be deferred as proposed by Duke are inappropriate. The proposed Public Staff adjustments are not only inconsistent with past Commission practices, but also inconsistent with how the Commission treats other deferred items, such as storm damage, the Catawba levelization, construction work in progress, etc. The Public Staff has presented no material basis for the Commission to change its practices. As witness Stimart testified, this would only provide utilities with an improper signal by penalizing actions which benefit customers. The Commission also rejects the recommendation of witness Baron. Witness Baron's recommendation is inconsistent with the Commission's past practices and would serve only to increase customer costs.

The Commission notes that three adjustments are necessary to the Bad Creek deferred costs in order for consistency to be effectuated with other Commission adjustments found to be fair elsewhere herein. First, the Commission concludes that the state income tax rate used in the Company's calculation should be adjusted to reflect the same rate and methodology used in other adjustments accepted by the Commission. Second, the Commission concludes that the overall cost of capital used to calculate the deferred return should be based, in part, on the cost df long term debt and preferred stock approved in this proceeding. Finally, the Commission concludes that the annuity factor applied to the deferred costs should reflect the overall cost of capital approved in this proceeding. Based on the above conclusions, the Commission determines that the appropriate level of depreciation and amortization to include in this proceeding is $302,474,000.

The next area of difference between the Company and the Public Staff is general taxes. The difference of $(634,000) is composed of the following differences:

(000's Omitted)

	Item	Amount
1.	Difference in allocation	$ 312
2.	Adjustment to payroll expense	$(169)
3.	Customer growth adjustment	$ (5)
4.	Annualization of operating and maintenance expense	$ 28
5.	Adjustment to fuel revenue	$ (37)
6.	FICA taxes	$(763)
	Total	$(634)

With regard to the Public Staff adjustment to FICA tax, Public Staff witness Maness testified that the amount recorded by the Company as FICA tax expense during the test year exceeded the amount calculated based on payroll expense and the FICA rate. Therefore, in order to attain as precise a match as possible for ratemaking purposes, he made an adjustment to synchronize FICA tax expense with per books payroll expense. The Company indicated, on Stimart Rebuttal Exhibit 1, that it was not contesting this adjustment, and offered no evidence to controvert the testimony of Public Staff witness Maness.

The Commission believes that it is appropriate to attain as precise a matching as possible between payroll expense and FICA tax expense. Therefore, the Commission concludes that the Public Staff adjustment of $(763,000) to correct the test year level of FICA tax expense is reasonable for purposes of this proceeding.

All of the other Public Staff adjustments to general taxes are related to adjustments already discussed elsewhere in this Order. Since the Commission has adopted each of these adjustments, except the one involving a change to the Company's allocation study, the Commission concludes that the appropriate total adjustment to general taxes is $(946,000).

Based on the conclusions reached herein, the Commission concludes that the level of general tax expense appropriate for use in this proceeding is $153,284,000.

The Company proposed income taxes of $173,814,000. The Public Staff proposes $176,265,000. The differences between the Company and the Public Staff are summarized below:

(000's Omitted) Analysis of Differences	
1. Difference in allocation factors	$(2,772)
2. Differences in operating income	$ 7,686
3. Interest synchronization	$(2,463)
Total Difference	$ 2,451

These items all relate to issues which are decided elsewhere. Based upon the Commission's decision of these issues, the Commission determines that the proper level of income tax expense under present rates is $179,646,000.

The Commission notes that the Public Staff and the Company have both incorporated the change in state income tax rates in their respective final positions in this proceeding. As part of this incorporation, the parties used an average state income tax surcharge of 2.5%. The Commission has reviewed these calculations and finds them to be appropriate for this proceeding, when adjusted for the cost of service adjustments adopted by the Commission herein this Order.

The next area of difference in operating revenue deductions between the Company and the Public Staff is the amortization of investment tax credits. The $27,000 difference between the Company's final position and the Public Staff's final position is composed solely of the adjustment made by the Public Staff to the factors used to allocate system costs to N.C. retail operations. Since the Commission has rejected the allocation factor adjustments recommended by the Public Staff, as set forth in this Order, the Commission concludes that the Public Staff adjustment of $27,000 is inappropriate.

Based on the foregoing the Commission concludes that the level of amortization of investment tax credits appropriate for use in this proceeding is $(10,781,000).

The Company included in operating revenue deductions a separate line item adding back the net tax effects of its accounting and update adjustments to its initial filing. The Public Staff did not adopt this adjustment. Based on the foregoing, the Commission concludes that this adjustment made by the Company in its final position should be rejected for ratemaking purposes in this proceeding.

Based upon the Commission's findings set forth herein, the Commission concludes that the overall level of operating revenue deductions under present rates appropriate for use in this proceeding is $1,994,619,000, made up of the following components:

(000's Omitted)

Item	Amount
Fuel used in electric generation	$ 450,106
Non-fuel purchased power and net interchange	249,412
Wages, benefits, materials, etc.	669,698
Depreciation and amortization	302,474
General taxes	153,284
Interest on customer deposits	780
Income taxes	179,646
Amortization of investment tax credit	(10,781)
Total operating revenue deductions	$1,994,619

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 115

The evidence relating to this finding of fact is presented in the testimony and exhibits of Company witnesses Lee, Osborne, Ibbotson and Erickson and Public Staff witness O'Donnell. In its application, the Company utilized its actual per book capital structure as of December 31, 1990, consisting of 49.82% common equity, 9.68% preferred stock and 40.50% long-term debt.

Both witnesses Lee and Osborne testified that maintaining the Company's AA bond rating is a major financial goal of the Company and a key to the retention of the Company's credit worthiness and financial strength so that the Company can obtain new financing when necessary, in both good and bad capital markets. Witnesses Lee and Osborne testified that one of the most important determinants of the Company's bond rating is its coverage of fixed charges, and they pointed out that Duke's Securities Exchange Commission interest coverage ratio is currently lower than it has been at any time since 1983. Witness Osborne stated that maintaining the capital structure of the Company at approximately its present levels of common equity and long-term debt is necessary in order to enable the Company to maintain a fixed charged coverage ratio at a level necessary to retain its AA bond rating. Witness Osborne further testified that the importance of maintaining Duke's credit worthiness is shown by what occurred in the mid-1970s in tight capital markets when Duke was unable to obtain any financing after its bond rating had dropped to single A. This situation caused Duke to stop work at certain construction projects which resulted in increased costs for those projects. Witness Osborne also pointed out that certain rating agencies have expressed concern about the negative trend in Duke's coverage of fixed charges and have emphasized the importance of the outcome of this rate case on Duke's credit rating since Duke is approaching the lower limits of the AA rating.

On cross-examination, witness Osborne challenged the notion that increasing the leverage in Duke's capital structure would result in any savings to ratepayers. He pointed out that, according to studies conducted by Nobel laureates Miller and Modigliani, and more recently (at the request of the Florida Public Service Commission) by Dr. Eugene Brigham and his colleagues, variations, within broad limits, in the proportions of the capital structure do not have a significant effect on the overall total cost of capital, but result only in internal shifts in the cost of capital in the various components of the capital structure.

Witness Osborne also identified changes which had occurred since Duke's last rate case in 1986 which more than justify a more conservative capital structure. He stated as follows:

> Subsequent to the 1986 order from this Commission, there have been several changes in the environment that necessitated the change in the capitalization that the Company's undertaken. I will list a couple of those.
>
> First of all, the government implemented a two-stage reduction in corporate income taxes because coverage is a pre-tax calculation and because the Company passed through to its customers the full benefit of this tax reduction, the coverage and the financial strength of the Company was reduced accordingly when we passed on those tax cuts to the customers.
>
> Second, at the time of the case in 1986, we had approximately half a billion dollars in short-term investments, cash, and cash equivalents that were the proceeds from the Catawba sales and the depreciation of McGuire, as I mentioned before, that permitted us to avoid new financing. Indeed, we avoided new money financing for the entire period until 1990. That money is now gone, and we now have a very active construction program under way.
>
> Third, the capital expenditures investment in electric plant that we have made on average for the three years ended 1990 was 50% higher than the capital expenditures that we made for electric plant during the three years ended 1986 which would have been the environment in which this Commission rendered its last order. I think those were indicative of the changes that have occurred in the environment in which we finance since the last rate order.

Dr. Ibbotson also testified that, in his opinion, the capital structure of Duke as proposed in this proceeding reflects appropriate financial management and should be maintained. Dr. Ibbotson also stated that an increase in the amount of debt in Duke's capital structure would leave the overall weighted cost of capital unchanged in the long run because while debt weight would increase, both debt and equity costs of capital would also increase. He pointed out that today's market is understandably very wary of companies with high leverage.

The Public Staff recommended a hypothetical capital structure of 46.30% common equity, 10.80% preferred stock and 42.90% long term debt, which is the same as was approved by this Commission in Duke's last rate case (Docket No. E-7, Sub 408), decided in 1986. Public Staff witness O'Donnell stated that, in his opinion, Duke's common equity ratio is too high and that its financial structure is more conservative than that of the average electric utility. Witness O'Donnell presented testimony and exhibits showing that Duke's capital structure is more conservative than the average of electric utilities with AA- bond ratings. On cross-examination, witness O'Donnell confirmed that the common equity ratios of two AA- electric utilities which were not included in his prefiled exhibit were 49.9% and 50.1%, respectively, and that the common equity ratio of the group of 15 electric utilities which he used as comparable companies in his rate of return analysis was 48.2%, compared with Duke's 49.5%. (Duke O'Donnell Cross Examination Exhibit 1). Witness O'Donnell testified, however, that he had made no effort to determine the amount of nuclear generation in the mix of the other AA- electric utilities, and he acknowledged that Duke had a much higher nuclear generation exposure than the others. Witness O'Donnell also stated that he did not disagree with the result of the studies of Miller and Modigliani, and confirmed by Dr. Brigham, to the effect that increases in the leverage of a company do not result in significant decreases in its overall weighted average cost of capital.

On rebuttal, Dr. Erickson testified that, in his opinion, it would be a mistake for the Commission to undertake to "micromanage" Duke's capital structure in the manner proposed by the Public Staff. Dr. Erickson also agreed with the results reached by the studies of Professors Miller and Modigliani and Dr. Brigham, which prior witnesses had confirmed. Additionally, Dr. Erickson testified that an effort by the Commission to micromanage Duke's capital structure might result in an overall increase in the total cost of capital, resulting from negative assessments by investors in the capital markets of the regulatory environment. Dr. Erickson agreed with witness Osborne that the Miller-Modigliani effects, plus the additional effect of such a negative assessment of the regulatory environment, could more than eliminate witness O'Donnell's calculated savings that would result from a hypothetical capital structure as recommended by the Public Staff, which were based on the assumption that none of the cost rates of the capital structure components would change even though the weight of the components would change.

On cross-examination, Dr. Erickson elaborated upon his opinion that the Commission should avoid micromanaging the Company's capital structure. He acknowledged that the Commission had granted a targeted capital structure to Duke in prior years, but distinguished prior years from the present by the following testimony:

> The situation that we have got here is that we had a cataclysm on our hands in terms of the energy crisis and rampant inflation when the earlier situation was described, and I think the Commission acted very responsibly to the best interests of North Carolina ratepayers and the economy of North Carolina in that circumstance, and I applaud those decisions. But we have a different situation now. And the different situation is that Duke's coverage ratios have been sliding. The Company performs very well in terms of the prices that it delivers electric power to the consumers and industries of North Carolina for

under their rate schedules. They're concerned about the future needs of this State. . . . They're not now buffeted by the extraordinary external events that took place in the historical period that we're discussing. The management has a capital structure that allows them to deliver electricity to the consumers in North Carolina, compared to the national averages or to other utilities in the State of North Carolina, at very attractive prices. And I think that the Commission ought to respect management's decisions with regard to what they think an appropriate capital structure for the Company is. It is not an overstatement to say that the American economy is awash [in] entirely too debt-heavy capital structures. . . . I don't think it would be good public policy for this Commission to second-guess the management of what I regard to be a very well-managed company at a time when the economy at large needs more equity rather than less equity in the capital structures of not only its electric utilities but also the rest of industrial America as well. I just think it would be a mistake.

When asked whether he had done a study to show that witness O'Donnell's estimated $20.5 million of savings from adjusting the capital structure would not be realized in actuality, Dr. Erickson said that he had done a study based on the work done by Dr. Brigham, and that instead of a $20.5 million in savings that witness O'Donnell proposes, based on the Brigham study it would be in the order of an imputed, or assumed, $5 million of savings, and that it would take only a very small increase in the overall weighted average cost of capital as a result of adverse investor reaction to regulatory micromanagement to have that $5 million of savings evaporate entirely.

The Commission is mindful of the observations made in our Order in Duke's last general rate case (Docket No. E-7, Sub 408), to the effect that Duke's common equity ratio would be closely examined for reasonableness and appropriateness on a case-by-case basis in the future. The Commission's prior decisions, however, on matters which affect the allowed rate of return do not bind this Commission as res judicata. See, e.g., State ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 377, 395, 206 S.E.2d 269 (1974). This is because the factors which affect the reasonable rate of return are constantly changing. The Commission has carefully considered all of the evidence in this case, including the tendency of the reduction in income tax rates since 1986 to make it more difficult to maintain coverage ratios, the deterioration of Duke's fixed charge coverage ratios since 1986, the general trend since that time for the capital structures of electric utilities to become more conservative than they were then, the increase in Duke's capital expenditures and financing requirements, and the fact that Duke's actual common equity ratio at the present time is very near the targeted common equity ratio in its long term financial plan. The Commission concludes, on the basis of these factors and evidence, that Duke's actual capital structure as of the end of the test period is within the zone of reasonableness and is appropriate for use in this case.

The Commission also notes that Duke witness Osborne was questioned concerning the equity in Duke's subsidiaries and that the Company was asked to prepare a late-filed exhibit showing the equity in subsidiaries, which the Company did. Although no witness recommended that the equity in subsidiaries be removed from Duke's capital structure, that was apparently the purpose of the questions and the request. The Commission concludes, however, that no such adjustment is appropriate. An identical adjustment was proposed by the Attorney General in Duke's last rate case and was rejected by the Commission. The Attorney General appealed this issue to the Supreme Court. The Supreme Court affirmed the Commission, stating that no adjustment was appropriate because "the assumption must be that [subsidiary capital is] derived from each source of capital in the same ratio as each bears to the other on Duke's books." State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 694-695, 370 S.E.2d 567 (1988). The same holds true in this case.

Having carefully considered all of the evidence, it is the Commission's judgment that Duke's actual capital structure is within reasonable bounds under all of the circumstances. The Commission finds and concludes that the appropriate capital structure for Duke in this proceeding is as follows:

Long Term Debt	40.50%
Preferred Stock	9.68%
Common Equity	49.82%
Total	100.00%

As mentioned above, the Commission in its Order issued on October 31, 1986, in Duke's last general rate case proceeding (Docket No. E-7,Sub 408) noted its concern regarding the level and the upward trend of the common equity component of Duke's capital structure. Specifically, the Commission stated as follows:

> Notwithstanding the fact that the Company's actual capital structure as of July 31, 1986, has been adopted for purposes of this case, the Commission is genuinely concerned, for ratemaking purposes, with the continuing upward trend in the common equity component of Duke's capital structure. For instance, Duke's Financial Forecast (March 1986) projects that the common equity component of the Company's capital structure will increase to 50% by 1988, with a reduction in the long-term debt ratio to 40%. The Commission believes it is appropriate to place Duke on notice that the Company's actual capital structure will be closely scrutinized and examined for ratemaking purposes in future general rate cases. Such case-by-case analysis may ultimately cause the Commission to conclude that the Company's capital structure has in fact become too conservative and equity thick for ratemaking purposes, so that it would then be appropriate to base the Company's rates on a hypothetical capital structure. Therefore, Duke is hereby placed on notice that future increases in the Company's common equity ratio will be closely examined for ratemaking reasonableness and appropriateness on a case-by-case basis. The Company should not proceed on the assumption that our use of the actual capital structure in this case will serve as a precedent to ensure use of the actual capital structure for ratemaking purposes in future general rate cases.

For reasons presented above, the Commission has concluded that Duke's actual capital structure as of December 31, 1990, is appropriate for use herein. Such capital structure reflects a common equity component of 49.82%. However, the Commission continues to be much concerned, for ratemaking purposes, with what appears to be a continuing upward trend in the Company's common equity ratio.

Therefore, the Commission is compelled to place Duke on notice in the strongest possible terms that its common equity ratio for ratemaking purposes is at or very near the upper-bound of reasonableness.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 116

The evidence relating to this finding of fact is presented in the testimony and exhibits of Company witness Stimart and Public Staff witness O'Donnell.

The positions of the Company and the Public Staff with respect to the embedded cost rates for long-term debt and preferred stock, as shown in their respective initial positions, are as follows:

	Company As Filed	Public Staff
Long-Term Debt	8.78%	8.54%
Preferred Stock	7.74%	7.54%

The embedded cost rates proposed by the Public Staff involved two adjustments: (1) the updating to June 30, 1991, of the embedded costs to reflect changes through that date; and (2) the adjustment of embedded costs of long-term debt to include current maturities in the calculation.

The Company agreed with and accepted the Public Staff's updating of the embedded cost rates to June 30, 1991, but opposed the inclusion of current maturities in the calculation of the long-term debt embedded cost. Witness Stimart testified that the Company has consistently excluded current maturities from the cost of capital calculations in rate cases in the past. He stated that this is necessary in order to properly correlate the Company's rate base with the long-term debt that supports that rate base. Excluding current maturities is also consistent with the Company's public financial reporting of its capital structure which is relied upon by investors, and with past Duke Power Company decisions of this Commission. The Public Staff offered no compelling evidence that would tend to justify the inclusion of current maturities of long-term debt in the calculation of the embedded cost of such debt.

Upon review of the evidence the Commission finds and concludes that the embedded cost rates should be updated to, and calculated as of, June 30, 1991, so as to reflect known changes, but that issues of long-term debt that will mature during the current year should not be included in the calculation for the reasons stated by witness Stimart. Accordingly, the Commission finds that the appropriate embedded cost rates for use in this proceeding are as follows:

	Embedded Cost Rate
Long-term Debt	8.60%
Preferred Stock	7.54%

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 117 - 120

The evidence relating to these findings of fact is found in the testimony of Company witnesses Ibbotson and Erickson, Public Staff witness O'Donnell and CUCA witness Solomon.

As is often true in major rate cases before this Commission, we are presented here with expert testimony as to the cost of common equity capital that varies considerably in both methodology and final result. Three distinct methodologies were employed by the witnesses: the discounted cash flow model (DCF) and the capital asset pricing model (CAPM), both of which are market-based models, and the comparable earnings analysis, which is an asset/earnings approach. The Public Staff and CUCA witnesses relied primarily on the DCF, with the Public Staff witness relying secondarily on comparable earnings. Duke's principal rate of return witness, Dr. Ibbotson, relied on the CAPM. On rebuttal, Dr. Erickson stressed the comparable earnings analysis, but also developed an estimate based upon the DCF.

It is the task of this Commission to weigh all of the evidence and to arrive at a rate of return, which, in the mandate of the statute, will:

> . . . enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors. (G. S. § 62-133(b)(4))

As the North Carolina Supreme Court has said, "The determination of what constitutes a fair rate of return requires the exercise of subjective judgment by the Commission . . . ." State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 23, 287 S.E.2d 786 (1982). The statute does not direct or ~~suggest~~ any particular methodology for our use in arriving at this judgment.

Moreover, the textbooks on public utility ratemaking do not suggest that any one method yields better results than others or should be relied upon to the exclusion of others. For example, Professor Charles F. Phillips, in his book The Regulation of Public Utilities (1988), devotes a chapter to a critique of each of the principal methodologies, including the three utilized in this case, and concludes as follows:

> It is clear that determining the cost of capital is not an exact science. It is based on as objective and comparable data as possible, but experience and judgment must be used in drawing conclusions from that data. In the words of the National Energy Board:
>
> One of the few things upon which regulated industries, the regulatory agencies, and the courts which review their decisions have all been agreed is that the consideration of the two objectives, just and reasonable rates or prices to the consumer, and just and reasonable return to the regulated enterprise, is a function requiring informed and scrupulous judgment. Many tests and techniques for assisting the process of reaching a just decision have been used, but no single test is conclusive, nor is any group of them definitive: whatever tests may be used, in the last analysis the adjudicating body cannot escape

> the responsibility of exercising judgment as to what, in a stated set of circumstances, is a just and reasonable return or rate of return, or what is a range of justness and reasonableness of rate of return.
>
> It is especially difficult to estimate the cost of equity capital. Given the variety of approaches, it is little wonder that estimates of the cost of equity capital differ significantly. (Id. at pp. 380-381.)

Similarly, the authors of Principals of Public Utility Rates, J. Bonbright, A. Danielsen and D. Kamerschen (1988), state that:

> Despite the apparent rigor and precision of the financial models used to estimate the cost of equity, much judgment is required in the application of these models. Seven-decimal point estimates based on elaborate models give a false air of precision (Bryer, 1982, p. 47). No single group test or technique is conclusive. Therefore it is generally accepted that commissions may apply their own judgment in arriving at their decisions. Support for this notion is found in the Hope case in the end-result doctrine. It is the end result that is important and not the methods used to arrive at the rates. (Id. at p. 317)

As stated above, the parties and the expert witnesses in this proceeding did not agree upon any single methodology for arriving at their recommended fair rates of return on common equity. There is substantial authoritative support for the proposition that all available methodologies for estimating the cost of common equity are imperfect and judgmental, and this suggests that no one method should be relied upon exclusively. We therefore conclude that the final objective of arriving at our judgment on fair rate of return on equity would best be served, not by selecting a single methodology, but rather by carefully evaluating the assumptions and underpinnings of all of the methodologies and the manner in which they have been applied, and arriving at our best judgment consistent with that evaluation and other relevant facts.

The Company's principal witness as to fair rate of return on equity was Dr. Roger W. Ibbotson, Professor of Finance at Yale University and President of Ibbotson Associates, a Chicago-based financial consulting firm. Dr. Ibbotson estimated Duke's cost of equity using the CAPM, which defines the cost of equity to be equal to the sum of the rate of return on a riskless security plus an equity risk premium, which is an additional return for the risk of holding the particular security (in this case Duke's common stock). The risk premium is estimated by multiplying the beta (a measure of risk) of Duke's common stock by the expected additional return which an investor expects to realize by investing in a diversified market portfolio rather than in the riskless security. For the riskless security Dr. Ibbotson used an average of recent yields on 20-year U. S. Treasury bonds, selected mainly because that maturity matches more nearly the horizon over which equity capital is committed to Duke Power Company. For his estimate of the expected equity risk premium of the market as a whole, Dr. Ibbotson used 7.1%, which was developed in Ibbotson Associates' Stocks, Bonds, Bills and Inflation 1991 Yearbook, and is the arithmetic average of the differences, or spreads, between the annual total returns on the stock market (represented by the S&P 500), and the average annual income returns on 20-year treasury bonds, over the period 1926 through 1990. Dr. Ibbotson explained that this period was used because it is the longest period for which there is good quality data, and that the use of the longest available period yields the best estimate of the risk premium because the risk premium is a random variable and therefore the accuracy of the estimate increases with the period over which it is measured. Using a risk-free rate of 8.55%, a beta for Duke of 0.65 and a market risk premium of 7.1%, Dr. Ibbotson concluded that the current required rate of return on equity for Duke Power Company is 13.17%, which includes no allowance for down markets or flotation costs.

On cross-examination, Dr. Ibbotson conceded that there is some judgment involved in the CAPM methodology, but he said that in his opinion there was less judgment in the CAPM than in the DCF, principally because of the large effect of the DCF analysts' estimate of investors' expected growth rate to infinity. He confirmed that there are certain assumptions in the CAPM, as in any model, including the DCF, and that such assumptions in the CAPM included the following: (a) that unsystematic risk (risk peculiar to a particular company) can be diversified away by the ownership of a diversified portfolio; (b) that beta is a reasonable measure of the relevant risk, i.e., the risk that cannot be diversified away; (c) that the S&P 500 composite is representative of the U. S. equity market; and (d) that the equity markets are dominated by diversified investors. Dr. Ibbotson stated that in his opinion all of these are reasonable assumptions and that, on the whole, the CAPM deals better with reality than the DCF.

With respect to his use of the Value Line beta, Dr. Ibbotson testified that it is the most widely circulated beta and the prevailing one used in this country. He was shown lower betas computed by Merrill Lynch and Standard & Poor's, respectively, but he testified that he had absolutely no knowledge about how they were computed and would not accept or subscribe to them. He pointed out that the adjustment which Value Line makes to its beta has been shown to reduce the estimation error of the beta and that studies have been made which demonstrate that fact.

Dr. Ibbotson was shown Value Line write-ups with respect to four troubled electric utilities (Tucson Electric, El Paso Electric, Illinois Power and Public Service of New Mexico) which have the same Value Line beta as Duke (0.65) but which are all in financial difficulties at the present time and have Value Line safety ranks and other indicia of unsystematic risk which show that they are riskier than Duke. Dr. Ibbotson pointed out that the events that have caused the unsystematic risk of these four companies have already been "captured" by substantial downward adjustments of their stock prices; that the market has "equilibrated" the bad news about the companies so that their stock prices are low enough to make them equally attractive, as investments, with companies without such troubles, such as Duke. He pointed out that while Duke ranks higher in safety and financial strength than the other companies, Value Line is negative on the stock of Duke as well as the others, in that it ranks all of them as a 4 (below average) in "Timeliness", which is the stock's probable relative market performance in the year ahead. In fact, while Duke and three of the "troubled" utilities are ranked 4 for timeliness, Illinois Power is actually ranked 3, which is average. (See CUCA Ibbotson Cross-Examination Exhibits 1 through 4.)

Dr. Ibbotson pointed out that beta measures the riskiness of a stock relative to the market as a whole and that Duke's stock has the same sensitivity to overall market movements as Tucson Electric and the other companies with a beta of 0.65; thus approximately the same systematic risk. He stated that since the unsystematic risk can be and is diversified away by the holding of a balanced portfolio, no incremental risk premium is appropriate for higher unsystematic risk, so that firms with highly divergent "safety ranks" can have the same cost of capital. He also pointed out that as the price of a poorly managed company gets low enough, and the price of a well managed company gets high enough, they both can have the same expected total return to investors. He stated that companies with bad management do not have higher expected returns than companies with good management and therefore both could have the same beta and the same cost of capital, which is the expected return rather than the experienced return. Dr. Ibbotson pointed out that the strength of the CAPM is demonstrated by the fact that it can derive a reasonable cost of equity capital for these troubled companies. The DCF model, which is based on current dividend yield and growth in dividends, is not capable of deriving a cost of equity capital for these troubled companies which have no current yield.

With respect to his selection of the risk-free rate, Dr. Ibbotson agreed that the analyst must decide what maturity of U.S. Treasury instrument to use as a proxy for the risk-free rate, but he said that the choice does not significantly impact the result. He stated that the reason for using long-term government bonds in this case is that such bonds represent a horizon closer to the horizon over which common stock investors commit capital to Duke Power Company. He also pointed out that 20-year bonds have a longer span of historical data and that utilities themselves make long-term commitments of the capital. Over the 20-year horizon or holding period of the 20-year bond, the government bond is free of both default risk and interest rate risk.

Dr. Ibbotson pointed out that the fact that Duke may be back for rate relief in two or three years does not affect the holding period (20 years) which he uses in his CAPM application, but that what is important is that the common stock investors themselves have long-term horizons and that the maturity used for the risk premium and risk-free rate should match that horizon.

With respect to his use of long-term data (i.e., from 1926 through 1990) in deriving his risk premium, Dr. Ibbotson explained that the actual annual realized spreads between risk-free returns and returns from the S&P 500 stocks are random, i.e., they are unpredictable and relatively volatile. He pointed out that he had conducted correlation studies which indicated specifically that the experienced annual risk premiums follow a random walk, producing a correlation coefficient of 0.0115, indicating no trend whatever. He stated that this correlation coefficient was evidence of the random walk of the annual risk premiums actually experienced. Thus, taking the average of the longest term that actual good data are available provides investors with the best information and basis for arriving at their expected risk premium. The expected risk premium is not random, but is stable and rational.

Dr. Ibbotson testified that he has never used anything less than all of the data available in developing his risk premium; that the data that he uses is data that he publishes and sells, and that it has never been, and is not capable of being, manipulated by him. Dr. Ibbotson explained the mathematical basis for using an arithmetic mean in calculating the historical risk premium, and he also pointed out that the arithmetic mean will translate over time to a geometric mean (i.e., a compounded annual return) which is a lower number. Dr. Ibbotson pointed out that the correctness of using the arithmetic mean is clearly and fully established as a mathematical fact, and is not subject to opinion or judgment.

Dr. Ibbotson concluded by pointing out there were three Nobel prizes granted for work in connection with the cost of capital, and that all of them were associated with the CAPM: Markowitz for his work on diversifying away the unsystematic risk; Sharp for writing the CAPM model itself; and Tobin for showing how investors treat risk. He testified that the CAPM is a superior method of estimating the cost of capital and one that he recommended for use by this Commission.

Public Staff witness O'Donnell employed two methods in his analysis of the fair rate of return for Duke Power Company. The first method was the constant growth DCF model. He performed a DCF analysis on Duke Power as well as on a group of 15 electric utilities which he concluded were similar in risk to Duke Power. In his application of the DCF model, witness O'Donnell determined the dividend yield for Duke to be 6.0%, arrived at by dividing the price of Duke's stock each week over the period January 25, 1991, through July 22, 1991, by Value Line's then forecast of dividends to be paid over the next 12 months. By the same technique he arrived at an average dividend yield of 7.1% for the comparable group of companies. He then examined 10-year historical growth rates in earnings, dividends and book value from Value Line and Value Line's forecasted growth in earnings, dividends and book value to 1994 through 1996. Based upon this analysis he arrived at a range of DCF required returns on equity of 11.60% to 12.10% for the comparable group and 11.25% to 11.75% for Duke.

For his comparable earnings analysis, witness O'Donnell examined earned returns on equity of various industries, both regulated and unregulated, as well as of his comparable group of electric utilities, over the 10-year period from 1981 through 1990, yielding the following results:

Item	1990	5-year Average	10-Year Average
All Industry Composite	11.7%	12.34%	12.26%
Electric Utility Industry	11.8%	12.5%	12.8%
Comparable Electric Utilities	13.0%	13.9%	13.8%
Duke Power Company	12.7%	13.4%	13.3%

Based upon his review of these comparable earnings data, witness O'Donnell concluded that Duke's cost of equity was in the range of 11.75% to 12.75%.

In determining his final cost of equity recommendation, witness O'Donnell stated that he relied more heavily on his DCF analysis than his comparable earnings analysis. He concluded that the current investor return requirement for Duke Power Company was in the range from a low of 11.50% under his DCF analysis to a high of 12.75% under his comparable earnings method. He recommended a fair rate of return for Duke Power Company on its common equity of 12.0%, which amount included no allowance for down markets or flotation costs.

On cross-examination witness O'Donnell agreed that the DCF involves significant judgment on the part of the analyst, especially with respect to the estimate of investor's growth expectation. He also agreed that his version of the DCF is an annually-compounding version, whereas Duke's dividends are paid quarterly, and that there are versions of the DCF model which make allowance for the quarterly compounding of dividends and therefore produce higher costs of capital on the same assumptions as to growth, dividend and price. He confirmed that, based on a study appearing in Public Utilities Fortnightly in July of 1987, the version of the DCF that he uses would produce approximately a 42 basis points lower rate of return than the quarterly compounding method. Witness O'Donnell stated that he did not agree with the quarterly reinvestment DCF method, though he recognized that the method is used by some rate of return witnesses.

With respect to his own estimated growth rate, witness O'Donnell stated that analysts' short term forecasts may currently be depressed because of the recession and the expectation of a slow recovery, so he relied more heavily on historical data drawn from the past 10 years as reported in Value Line. This historical data is reported on O'Donnell's Exhibit KWO-6.

Witness O'Donnell acknowledged that the comparable companies that were included in his DCF and his comparable earnings analysis, which purported to embrace all electric utilities with S & P bond ratings of A+ through AA and stock ratings of A, omitted at least five companies which met both of these screening criteria. He said that apparently the Compustat Data upon which he relied was incomplete. He also acknowledged that the Value Line data upon which he relied for both his DCF and comparable earnings analysis used year-end book values for purposes of computing rates of return, whereas Duke, Merrill Lynch, and Solomon Brothers (which Mr. O'Donnell had used in his 1990 North Carolina Power testimony) report earnings based on average common equity. He acknowledged that use of average common equity gives a higher earned return figure and that the 10-year average earned return on equity of the electric utility industry based on average values was 13.4% rather than the 12.8% he had utilized. (Duke O'Donnell cross-examination Exhibit 4). Similarly, it appeared that the "plow back ratios" as taken by witness O'Donnell from Value Line were computed by Value Line using a method different from the equation presented by witness O'Donnell in his prefiled testimony, and that witness O'Donnell's calculations did not yield results which coincided with the "plow back ratio" reported in Value Line.

Witness O'Donnell indicated on cross-examination that he suspected that allowed returns were falling in 1991. He was shown and examined a Merrill Lynch Quarterly Regulatory Report dated July 19, 1991 which indicated that in the first quarter of 1991 the allowed return on equity in electric rate cases averaged 12.9%. He was also shown and examined a copy of The Regulatory Focus by Regulatory Research Associates dated July 12, 1991, which shows that there were 13 cases decided in the first quarter of 1991 with an average allowed return on equity of 12.67% and five cases decided in the second quarter of 1991 with an average allowed return on equity of 12.9%. This would indicate that, if anything, the trend was increasing rather than decreasing.

Mr. J. Bertram Solomon testified on behalf of CUCA with respect to fair rate of return on common equity. He used the constant growth DCF model in arriving at his recommendation. Using price data over a period from February through July 1991, and the current applicable quarterly dividend rates, annualized, witness

Solomon calculated a dividend yield of 5.86%. He then derived a growth rate in a range from 4.8% to 5.2% based upon, first, a so-called internal growth-in-book value method represented by the equation ($g = br + sv$), where b is the retention ratio, r is the rate of return expected to be earned on the book value of the company and sv is the growth-in-book value expected to occur as a result of issuing new shares at premiums over book value. He also examined growth rates in Duke's earnings, dividends and book value over a 10-year period from 1981 through 1990, and short range forecasts made by certain analysts. Witness Solomon then recognized the quarterly payment of dividends by multiplying his dividend yield (5.86%) times the product of 1 + 1/2 the estimated growth rate ($1 + 0.5g$) to arrive at an adjusted dividend yield of 6%, which he added to his range of growth rates of 4.8% to 5.2%, to arrive at a range of 10.8% to 11.2% cost of common equity, and he recommended a fair rate of return on equity of 11%, representing the mid-point of that range. This contained no allowance for down markets or flotation costs.

Witness Solomon criticized Dr. Ibbotson's CAPM method and its application by Dr. Ibbotson. Witness Solomon addressed what he called the "restrictive assumptions" of the CAPM model. As to Dr. Ibbotson's application of the CAPM, witness Solomon criticized his use of 20-year government bonds as the proxy for the risk-free rate. Witness Solomon also criticized the beta as a measure of the relevant risk differentials between individual company stocks and discussed the differences in observed risk between Duke and Tucson Electric. By like token, witness Solomon criticized Dr. Ibbotson's use of the arithmetic average of one-year holding period returns to calculate his risk premium. It is clear that witness Solomon and Dr. Ibbotson do not agree upon the proper methodology to use in the determination of the cost of capital. Witness Solomon is clearly committed to the DCF and Dr. Ibbotson is committed to the CAPM. The record contains their arguments and justifications, and their criticisms of one another and their defense of their own methodologies. No useful purpose would be served in reciting those arguments and defenses at length in this Order. It is for this Commission to evaluate the evidence and the arguments of the expert witnesses and to reach its own judgment as to fair rate of return on common equity. State ex rel. Utilities Commission v. Duke Power Co., 305 N.C. 1, 287 S.E.2d 786 (1982).

During witness Solomon's direct examination, and on the cross-examination of Dr. Ibbotson, it was pointed out that the DCF approach used by witness Solomon is similar to the approach used in the development of the generic benchmark rate of return of the Federal Energy Regulatory Commission (FERC) and that the FERC had rejected the use of the CAPM in the development of that generic benchmark rate of return. On cross-examination, witness Solomon, when asked whether the FERC had ever used the generic model as the basis of a rate order, answered that "I don't know of any in which they have. I certainly don't believe they have." Witness Solomon also confirmed that, in a recent pronouncement by the FERC, a majority of the FERC stated that "the allowed rate of return is now determined individually for each utility on a case-by-case basis." The record indicates that the FERC has undertaken an evaluation of whether the generic rate of return serves any useful function. In the order setting that proceeding, two concurring Commissioners stated that:

> In addition, the Commission's experience during all the years it has calculated and published a generic rate of return shows the futility of continuing the exercise. The Commission has never adopted the generic rate of return in any proceeding. Parties to the proceeding have hardly ever based their testimony on the benchmark.
>
> We are also aware that rate of return analysts, including FERC staff, use a variety of rate of return estimation techniques such as comparable earnings and capital asset pricing models, in arriving at their estimates. Thus, to imply by publication of a model based on a single technique, that it alone is adequate, may be misleading and inaccurate. (Stimart Rebuttal Exhibit 5)

With respect to the DCF in general, witness Solomon confirmed that it is a model, and, as such, contains assumptions that do not conform to reality; that the constant growth DCF model assumes a continuous, constant, compound growth rate in dividends; that there will be a constant pay-out ratio in the payment of dividends in the future and that the price-earnings ratio of Duke's stock would remain constant over time. Witness Solomon confirmed that he developed his DCF yield for Duke by taking market price figures of Duke's stock over the six-month period from February through July of 1991, during a period when the price-earnings ratio of Duke's stock was near its peak of the last 10 years. Witness Solomon also confirmed that, if Duke's stock were currently traded at its average price-earnings ratio of the last 10-year period (eight times earnings), the price would be $21.50 per share.[1]

Witness Solomon conceded that there were practical problems in the application of the DCF model, but questioned whether there were theoretical problems as well. However, he confirmed that, in a textbook entitled The Regulation of Public Utilities by Charles F. Phillips, Jr., Professor of Economics at Washington and Lee University, Professor Phillips states that

> However, use of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio that is a fixed pay-out ratio and the assumption that dividends will continue to grow at rate g in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investor's capitalization rate and the cost of equity capital to a utility for application to book value, that is, on a original cost basis, are identical when market price is equal to the value. Indeed, DCF advocates assume that if market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered and vice versa. Many question the assumption that market price should equal book value, believing that the earnings of a utility should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing of stocks of unregulated companies. Most frequently, the major practical

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[1]Based upon the current annual dividend of $1.72 per share, a $21.51 price would represent a dividend yield of 8.0% rather than the actual yield of approximately 6.0%.

issue involves determination of the growth rate, a determination that is highly complex and that requires considerable judgment. (Id. at p. 377)

Witness Solomon confirmed that his method of deriving the dividend yield took account of a quarterly compounding effect, but did not make provision for the first year's growth in the dividend except to the extent that one of his price observations out of six contained the forward dividend. He confirmed that there were respectable analysts who insist that the equation for deriving the dividend yield should include such a provision for the forward one-year dividend. While on re-direct, witness Solomon suggested that such analysts were hired by electric utilities; he confirmed on re-cross that witness O'Donnell of the Public Staff used exactly that approach in his DCF application in this case.

Witness Solomon's testimony on cross-examination as to whether Duke could ever achieve the 5% growth in dividends implicit in his DCF result if the Commission Order agreed with his recommended 11% rate of return revealed a serious inconsistency in witness Solomon's recommendation. While witness Solomon agreed that Duke could not achieve a 5% growth in dividends if it earned 11% on equity, he stated that, in his opinion, investors expect that Duke would earn <u>more</u> than its allowed rate of return. However, in his prefiled testimony with respect to his DCF growth rate, witness Solomon testified that he thought investors were expecting Duke to earn about a 13% rate of return on equity, pointing out that Duke actually earned 13.1% on average common equity in 1990 and that, "this 13.1% was earned on rates incorporating allowed returns on common equity for North Carolina and South Carolina jurisdictions of 13.2% and 13.0%, respectively." On the one hand it appears that witness Solomon believes that investors expect Duke to earn close to its allowed rate of return (13%) and on the other hand, he thinks that investors expect Duke to earn more than its allowed rate of return. In any case, witness Solomon confirmed that over the past 10 years, Duke's average earned rate of return has been less than its average allowed rate of return.

Furthermore, witness Solomon confirmed that, if Duke is not able to earn more than its allowed rate of return, and if the Commission allowed his recommended 11% rate of return, then for the period 1992 through 2001, the compound rate of growth in Duke's dividends would be only 3.8%. (Duke Solomon Cross-Examination Exhibit 5.)

Dr. Erickson testified on rebuttal with respect to the cost of equity capital. He testified that in his opinion the cost of equity capital developed by witness Solomon was not a reasonable estimate. A straightforward application of the DCF technique used by witness Solomon yields estimates for Duke's cost of equity capital in the range of 9.8% to 10.3%. Dr. Erickson criticized witness Solomon's internal book value growth analysis as involving a serious inconsistency in that, although witness Solomon concluded that investors expect an earned rate of return on Duke's common stock of 13%, and therefore used a 13% rate of return on equity in his internal book value growth computation, witness Solomon concluded by recommending an 11% rate of return on common equity, which would clearly thwart investor expectations. Dr. Erickson pointed out that, if witness Solomon's 11% were substituted for the 13% in his book value growth formula, it would result in a growth estimate well below that which witness Solomon utilized in his final conclusion.

Dr. Erickson also presented a DCF approach which utilized the 6% dividend yield effectively used by both witnesses O'Donnell and Solomon, but developed an investor-anticipated growth rate of 7%, based upon his conclusion that investors expected a long-term real rate of growth in Duke's dividend equal to at least half the real rate of growth of the United States economy, which is 3.2%. Half of that amount is 1.6% which, when added to the long-term inflation forecast of Ibbotson Associates of 5.4%, gives a long-term expected growth rate of 7%. Dr. Erickson testified that this growth rate, combined with the 6% dividend yield, resulted in a cost of equity capital for Duke of 13%, which more nearly reconciles the varying conclusions of the other rate of return witnesses in the case.

Dr. Erickson also relied upon comparable earnings data for his conclusion that Duke's cost of equity capital is 13% or higher. He first examined the comparable earnings data provided in witness O'Donnell's Exhibit KWO-10 and concluded on the basis of that data that the range of average earnings of witness O'Donnell's comparable group of companies is 13.4%. Dr. Erickson also examined a group of 38 companies (both regulated and unregulated) having an S&P bond rating of AA- or better and concluded that the average return on equity of those companies was well in excess of 13%. (Erickson Rebuttal Exhibit 1) Then, using a Value Line beta range of 0.60% to 0.75% as a further screen, Dr. Erickson developed a group of 16 comparable companies, 14 of which are electric utilities, whose average earned rate of return is well in excess of 13%.

Dr. Erickson was cross-examined on his criticism of witness Solomon's use of a 13% anticipated rate of return and an 11% recommended rate of return on equity. Erickson concluded this testimony by stating that: "I personally believe that if you are going to recommend an 11% allowed return for Duke Power Company then it is a bit much to swallow to assert that investors aren't going to notice that and that they are going to anticipate 13% instead. I mean, that strikes me as a fairly inconsistent statement."

Dr. Erickson testified that what struck him initially about witness O'Donnell's testimony was his comparable company earnings analysis; that witness O'Donnell presented earned rates of return of companies earning in the 13% or better range, then "testified that he (O'Donnell) believed that those numbers justified a range of recommended rate of return of x, which is substantially lower." Dr. Erickson stated that, when he sees witness O'Donnell's comparable companies in a range of 13% and higher and Dr. Ibbotson's CAPM testimony in the range of 13%, and witness Solomon testifying that he believes that investors expect Duke Power to earn approximately 13% on its common equity, the question is whether there is a way to use the basic DCF philosophy to harmonize all of this evidence. He pointed out that the DCF approach that is consistent with these 13% rate of return indications suggests a growth rate in dividends of approximately 7%, and that such a growth rate was consistent with the maintenance of a real rate of growth (above the 5.4% long-term inflation estimate as reflected in Ibbotson & Associates' forecast) of about one-half the long-term historical real growth in the economy. He stated that he used the long-range real growth average from 1950 to 1990, and he explained his reason for selecting this period. He also explained that the 3.2% real growth was consistent with the real growth in the U. S. economy from as far back as colonial times. Asked to explain the basis of his assumption that investors expect Duke's real rate of dividend growth to be about one-half the real rate of growth in the U. S.

economy, Dr. Erickson testified that Duke's dividends per share from 1950 to 1990 have increased at approximately a 6.2% annual compound rate, and that if you subtract the average rate of inflation of that same period of 4.3%, you get 1.9% real growth, which is less than the real growth in the economy as a whole during that period, but more than half; and that he used one-half to be conservative.

The Commission is mindful of the fact that its conclusion on the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 699, 370 S.E.2d 567, 573 (1988). It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 F.2d 547 (1980). State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E.2d 786 (1982). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. Utilities Commission v. Power Company, 285 N.C. 377, 395, 206 S.E.2d 269 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." Utilities Commission v. Public Staff, 322 N.C. 689, 694, 370 S.E.2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented (and the weight and credibility thereof) in each case.

The Commission cannot guarantee that Duke Power Company will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if we could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds, and thus concludes, that the rates of return approved herein will afford the Company a reasonable opportunity to earn a reasonable return for its stockholders while providing adequate and economical service to its ratepayers.

The Commission concludes that, based on the record in this case, we should not adopt any single methodology or "model" for arriving at our judgment as to a fair rate of return on common equity for Duke. Two witnesses relied partially on the DCF and partially on comparable earnings. One relied entirely on the DCF. Another relied entirely on the CAPM. There is almost no area of agreement among these witnesses: witness O'Donnell's final recommendation is 12%; Dr. Ibbotson's is 13.17%; witness Solomon's is 11%; and Dr. Erickson's is 13% or higher.

We recognize that there are limitations in using the CAPM to determine the cost of equity, and that there is considerable difference of opinion over how good beta is as a proxy for relevant risk, over how long a period to utilize for determining the risk premium and over the choice of an appropriate maturity of U.S. Treasury instrument as representative of the risk-free rate in the CAPM. Although it appears that few regulatory agencies have adopted the CAPM as a primary basis for their return on equity decisions, there is no evidence as to how many regulatory agencies have adopted any particular model or methodology, including the DCF, for that purpose.

There are also problems and differences of opinion attending the DCF methodology as well as the CAPM. Nonetheless, estimates of cost of equity capital based on these methods are entitled to be given weight in reaching our final judgment in this case. We conclude, however, that the comparable earnings data produced by witnesses O'Donnell and Erickson should be given the greater weight in our determination, particularly the evidence presented by witness O'Donnell. The comparable earnings standard is, perhaps more than any other, consistent with the United States Supreme Court's holdings in the two universally accepted decisions on utility rate of return. In Bluefield Waterworks Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), the Court said (at pages 692-693):

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties. (Emphasis added)

Also, in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the Court said (at page 603):

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . By that standard the return to the equity owner should be commensurate with return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital. (Emphasis added)

We recognize that G.S. § 62-133 has adopted the test set forth in Bluefield as the standard to be used in this case. In State ex rel. Utilities Commission v. Morgan, 278 N.C. 235, 238, 179 S.E.2d 419 (1971), Justice Lake stated that, "In this State the test of a fair rate of return is that laid down by the Supreme Court of the United States in the Bluefield Water Company case. . . ." Therefore, comparable earnings evidence is entitled to great weight under North Carolina law.

The Commission has previously presented herein a summary of the comparable earnings analysis performed by witness O'Donnell. Witness O'Donnell's comparable earnings tests, excluding his comparable earnings DCF analysis, ranged from a low of 11.7% to a high of 13.9%. From this data, witness O'Donnell concluded that

Duke's cost of common equity was in the range from 11.75% to 12.75%. Based upon the entire evidence of record in this case, the Commission finds and concludes that this range, based on the comparable earnings methodology, more accurately than any other methodology reflects and encompasses Duke's cost of common equity for purposes of this proceeding. Further, the Commission finds and concludes based upon the entire evidence of record that within this range the appropriate point estimate of the cost of Duke's common equity is 12.5%. This cost rate is slightly above the mid-point of the 11.75% to 12.75% range found reasonable by witness O'Donnell based on his comparable earnings analysis.

Based upon the foregoing, and without selecting any one method as the sole basis for our conclusion, the Commission finds and concludes that Duke should be allowed in this case the opportunity of earning a return on common equity of 12.5%, which includes no allowance for down markets or flotation costs.

Based upon the Commission's findings with respect to the proper capital structure the appropriate cost rates for each component of capital reflected in that capital structure, the Commission further finds and concludes that the overall fair rate of return that Duke should be allowed an opportunity to earn on its rate base is 10.44%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 121

The Commission has previously discussed its findings and conclusions regarding the fair rate of return which Duke Power Company should be afforded an opportunity to earn.

The following schedules summarize the gross revenue and the rate of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order. As reflected in Schedule I Duke should be authorized to increase its annual level of revenues by $100,072,000 based upon the adjusted test-year level of operations:

SCHEDULE I
DUKE POWER COMPANY
North Carolina Retail Operations
Docket No. E-7, Sub 487
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 1990
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Electric operating revenue	$2,412,417	$100,072	$2,512,489
Operating revenue deductions:			
Operation and maintenance expenses:			
Fuel used in electric generation	450,106		450,106
Non-fuel purchased power and net interchange	249,412		249,412
Wages, benefits, materials, etc.	669,698	90	669,788
Depreciation and amortization	302,474		302,474
General taxes	153,284	3,222	156,506
Interest on customer deposits	780		780
Income taxes	179,646	37,848	217,494
Amortization of investment tax credits	(10,781)		(10,781)
Total operating revenue deductions	1,994,619	41,160	2,035,779
Net operating income for return	$ 417,798	$58,912	$ 476,710

SCHEDULE II
DUKE POWER COMPANY
North Carolina Retail Operations
Docket No. E-7, Sub 487
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1990
(000's Omitted)

Item	Amount
Electric plant in service	$8,337,371
Accumulated depreciation and amortization	(3,226,413)
Net electric plant	5,110,958
Materials and supplies	172,358
Working capital investment	130,127
Accumulated deferred income taxes	(813,344)
Operating reserves	(34,076)
Original cost rate base	$4,566,023

Rates of return:

Present rates	9.15%
Approved rates	10.44%

SCHEDULE III
DUKE POWER COMPANY
North Carolina Retail Operations
Docket No. E-7, Sub 487
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1990
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost Rates	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-term debt	40.50%	$1,849,239	8.60%	$159,035
Preferred stock	9.68%	441,991	7.54%	33,326
Common equity	49.82%	2,274,793	9.91%	$225,437
Total	100.00%	$4,566,023		$417,798
	Approved Rates - Original Cost Rate Base			
Long-term debt	40.50%	$1,849,239	8.60%	$159,035
Preferred stock	9.68%	441,991	7.54%	33,326
Common equity	49.82%	2,274,793	12.50%	284,349
Total	100.00%	$4,566,023		$476,710

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 122 - 142

The evidence for these findings is found in the testimony of Company witnesses Denton and Stimart, Public Staff witnesses Turner and McLawhorn, CUCA witness Phillips, and NCIEC witness Baron.

Percentage Revenue Increase

The Company proposed in this proceeding to increase the revenues for the major customer classes by the following relative amounts:

	Percent Increase
Residential	9.88%
General Service	9.43
Industrial	8.99
Lighting	4.86
Total Retail	9.41

Witness Denton testified that different increases were applied to the customer classes in order to help move each class rate of return toward the 10% band of reasonableness. Duke's proposed increases would result in rates of return for all customer classes which are within the band of reasonableness, except the industrial class, based on the Summer CP allocation method. The industrial class rate of return would also be closer to the band of reasonableness than it now is.

The Public Staff proposed in this proceeding to increase the revenues for the major customer classes by the following relative amounts:

	Percent Increase
Residential	2.32%
General Service	0.78
Industrial	4.65
Lighting	4.73
Total Retail	2.59

Witness Turner testified that no customer class should be increased more than two percentage points greater than the overall increase, and that the different increases would help move each class rate of return closer toward the 10% band of reasonableness. The Public Staff's proposed increases would result in rates of return for all customer classes which are within the 10% band of reasonableness, based on the Summer/Winter Peak & Average allocation method.

CUCA witness Phillips contended that each class of customers should be increased (or decreased) to the extent necessary to reduce the difference between each customer class rate of return and the overall rate of return by 50%. He advocated basing such rates of return on the Summer CP allocation method.

NCIEC witness Baron contended that each customer class should be increased (or decreased) to the extent necessary to reduce the industrial class rate of return to within the 10% band of reasonableness, based on the Summer CP allocation method.

The Commission recognizes that all parties desire to achieve customer class rates of return which are within the 10% band of reasonableness, and that they differ primarily over how to measure the band of reasonableness. For example, the Company's proposed increase for the industrial class would produce a rate of return outside the band of reasonableness and higher than the overall return, based on the Summer CP allocation method. The Company's proposed increase for the industrial class would produce a rate of return within the band of reasonableness and lower than the overall return, based on the Summer/Winter Peak and Average allocation method. The two allocation methods give opposite results for some customer classes.

The Commission further recognizes that the relative increases proposed by the Company and the Public Staff in this proceeding for each customer class are within one or two percentage points of being an across the board increase for the major rate classes. Furthermore, the Commission is mindful of the unsettled controversy over the appropriate allocation method to be utilized in future rate proceedings. Therefore, the Commission is of the opinion that the percent increase applied to each major customer class in this proceeding should be the same for all customer classes, except as specified hereunder.

Witness Denton also testified that Schedules GB, GT and IT are currently closed to new customers and need to be phased out. He indicated that the Company would like to encourage customers on those rate schedules to move to other open rate schedules, and that the Company proposes to increase those closed rate schedules by two percentage points more than the respective alternative open rate schedules.

Witness Turner testified that the Public Staff supported the proposal to increase the closed rate schedules by two percentage points more than the respective open rate schedules. Witness Phillips contended that Schedule OPT should be increased less than the other rate schedules in order to encourage customers to move from Schedule IT to Schedule OPT.

The Commission is of the opinion that Schedules GB, GT and IT should be increased two percentage points more than the respective alternative open rate schedules as proposed by the Company. Rate Schedule GB has been closed since 1981, and Rate Schedules GT and IT have been closed since 1986.

Adjustment for Revenue Shortfall

Company witness Denton testified that modifications proposed by the Company for Rate Schedules G, GA, I and OPT will cause some nonresidential customers to migrate from one rate schedule to another, resulting in a revenue shortfall compared to the revenue estimates utilized in this proceeding. The Company estimates a potential revenue shortfall of $16,183,000 based on the requested increase. However, not all customers who might receive a lower bill by migrating to another rate schedule will actually do so, based on the Company's past experience. Therefore, the Company proposes a revenue adjustment of $4,046,000 to recover the estimated revenue shortfall.

Witness Turner recommended that the proposed revenue adjustment be approved, with the proviso that the $4,046,000 amount be reduced to reflect the level of increase actually granted in this proceeding. He pointed out that the $4,046,000 is based on the requested increase.

Witness Denton also proposed to spread the revenue adjustment among all rate classes, including residential, on the assertion that the rate design modifications to Schedules G, GA, I and OPT will benefit all customers to some degree. He contended that the modifications will cause many nonresidential customers to change their usage patterns, that the change in usage patterns will create systemwide operating savings, and that the systemwide savings will benefit all customers.

Witness Turner opposed the contention that all customers would benefit from the rate design modifications, and he asserted that any usage changes that there might be are not quantified. He recommended that the revenue shortfall be assigned to those customer classes responsible for the shortfall.

Based on the foregoing, the Commission is of the opinion that the revenue adjustment should be allowed, and that the $4,046,000 proposed herein should be reduced proportionately to reflect the increase actually granted herein. The Commission is further of the opinion that fifty percent of the revenue adjustment should be recovered from the rate classes responsible for the shortfall, and fifty percent of the revenue adjustment should be recovered from all rate classes in proportion to the revenue requirement of each rate class.

Revenue Adjustments for Customer Growth, Weather Normalization

Witness Turner recommended that the revenue adjustments for customer growth and weather normalization should be incorporated into the revenue requirements for each affected rate class when designing rates. The recommendation was unopposed by any party.

The Commission is of the opinion that the revenue adjustments for customer growth and for weather normalization should be incorporated into the revenue requirement for each rate schedule, as applicable, when designing rates in this proceeding. Furthermore, the Commission recognizes that the revenue adjustments for customer growth and weather normalization are based on the present rates. Therefore, consistent with its treatment of revenue adjustments elsewhere herein, the Commission is of the opinion that the revenue adjustments should be revised to reflect the rate increases actually granted herein.

Schedule RTX

Witness Denton recommended that the Company be allowed to cancel Schedule RTX, the all-energy residential TOU rate schedule, due to low customer participation. He indicated that only 22 customers had signed up for the rate since 1982. He testified that small usage customers are not able to shift a significant amount of their kWh usage from on-peak to off-peak, so the all-energy TOU rate is not cost-effective for the Company.

Witness McLawhorn recommended that Schedule RTX be continued. He pointed out that the Company proposes to increase its promotion of TOU rates, including residential rate Schedule RT. He contended that Schedule RTX had not been promoted in the past, and that it should be given a reasonable opportunity to attract additional customers along with Schedule RT. He indicated that small usage customers would not be able to benefit from Schedule RT and should have an alternative.

Witness McLawhorn pointed out that CP&L and NC Power offer all-energy residential TOU rates in North Carolina and have greater participation in the rate than does Duke. He also pointed out that the term "experimental" should be removed from Schedule RTX in order to avoid giving potential participants the impression that the rate schedule is only temporary.

Witness Denton stated that the Company was willing to continue offering Schedule RTX provided the Company is not required to promote it aggressively. He also stated that the Company was willing to offer Schedule RTX without the term "experimental". No other party addressed this issue.

The Commission is of the opinion that the Company should continue to offer Schedule RTX, either as Schedule RTX or some other designation, and that the term "experimental" should be removed from the rate schedule and from any references to it.

In a related matter, the Company proposed a comparative billing program for Schedule RT. Witness McLawhorn recommended that Schedule RTX be included in the comparative billing program. Witness Denton concurred with the Public Staff recommendation, although he expressed reservations about whether the comparisons, could be shown on the actual bill because of space limitations. He also pointed out that the comparative billing program should still be limited to 1,000 volunteers on the Company system at a time.

The Commission is therefore of the opinion that Schedule RTX should be included in the comparative billing program with Schedule RT, and that the program may be limited to 1,000 customer volunteers on the Company system at a time.

Information to TOU Customers

Witness McLawhorn recommended that the Company provide its residential TOU customers with a calculation of their savings (or loss) over non-TOU rates on their monthly bills. He contended that the information would provide the customers with useful data on their consumption versus the costs to consume.

Witness Denton accepted the Public Staff recommendation, but expressed reservations about whether there was sufficient space on monthly bills to include the information. He indicated that the Company is currently studying the feasibility of providing the information in some other fashion, and is willing to provide the information periodically. No other party addressed this issue.

The Commission is of the opinion that the Company should be required to report back to the Commission within six months on its study of the feasibility of providing, in some fashion, periodic information to residential TOU customers regarding the savings or loss for the TOU rates versus non-TOU rates.

Off-Peak Holidays for TOU Rates

The Company proposed in this proceeding to include six holidays as off-peak periods for Schedule RT. Witness McLawhorn concurred with the Company's proposal to include the six proposed holidays: New Year's Day, Memorial Day, July 4, Labor Day, Thanksgiving Day, and Christmas Day, as off-peak periods for Schedule RT. In addition, he recommended inclusion of Good Friday and the Friday after Thanksgiving as additional off-peak holidays. In support, he stated that the peak loads on these days are within the range of peak loads experienced on the Company-proposed holidays, and he further stated that these were the eight holidays recognized by both CP&L and North Carolina Power as off-peak periods. In addition, he recommended that they be designated as off-peak periods for Schedules RTX and OPT as well. Witness Baron also stated that holidays should be designated as off-peak for Schedule OPT.

Under cross-examination, witness Denton stated that he accepted the Public Staff's recommendation to include the two additional holidays as off-peak for the residential time-of-use schedules, but he opposed their inclusion as off-peak for Schedule OPT. He contended that the OPT customers' usage is not significantly different on holidays from their usage on non-holidays, and that these customers would see bill savings on holidays without changing their consumption.

Witness McLawhorn, under cross-examination, reaffirmed his testimony that these holidays be included as off-peak periods for Schedule OPT because of the lower system operating costs experienced on these days. He stated that it was not appropriate to include them as off-peak for Schedule IT because Schedule IT is a closed rate, and the Company is attempting to encourage these customers to move to Schedule OPT. Making Schedule IT more attractive would be counter to this effort.

The Commission concludes that the six holidays proposed by Duke and the two additional holidays proposed by the Public Staff should be considered as off-peak periods for Schedules RT, RTX, and OPT. It is clear that system operating costs are generally lower on these holidays than non-holidays and should be reflected in all time-of-use schedules, save those that are currently closed and/or being phased out.

The Commission further concludes that any revenue shortfall resulting from the designation of additional off-peak holidays herein should be recovered from the rate schedules responsible for the shortfall.

In a related matter, witness McLawhorn stated that Duke should analyze the load characteristics of Martin Luther King Day for its consideration as an off-peak holiday. He further stated that Duke should file its analysis with the Commission in the manner that Carolina Power & Light Company and North Carolina Power are currently required to file.

Witness Denton, under cross-examination, stated that the relationship of the peak loads of the eight holidays discussed previously to their monthly peak loads is between 55% and 65% while the King holiday has been between the upper 70%'s and upper 80%'s of its monthly peak over the last few years. For this reason, he stated that the King Holiday is not appropriate for inclusion as an off-peak period at this time, but Duke will continue to monitor it for load impact changes.

The Commission concludes that the Company should monitor the system loads on Martin Luther King Day to determine if or when its load characteristics are becoming more representative of the other off-peak holidays, and it should address the status of its review in the Company's next general rate application.

Demand and Energy Components of Schedule OPT

CUCA pointed out that the majority of Duke's nonresidential sales are made under Schedule OPT. Duke proposed to increase revenues paid by customers served under Rate Schedule OPT by 8.49% and to reduce the summer on-peak period by two hours. In preparing its proposed rates, Duke recommended increases of approximately 10% for the demand charge components of that rate; however, the Company proposed nonfuel increases of 13.5% for the on-peak component and 20.69% for the off-peak component of Rate Schedule OPT. CUCA complained that, except for a limited discussion of the proposed reduction in summer on-peak hours, Duke provided no explanation for its proposed modifications to Rate Schedule OPT.

Although Duke's cost-of-service studies did not produce customer, demand, and energy costs for each component of its nonresidential rate schedules, they do show average customer, demand, and energy costs for industrial service. According to CUCA, the Company's "per books" Summer Coincident Peak cost-of-service study indicates that Duke's industrial customer costs were $98.96 per customer per month under present rates and $104.65 per month under proposed rates; that Duke's fixed costs were $14.85 per kilowatt per month under present rates and $16.75 per kilowatt per month under proposed rates; and that Duke's variable costs were 1.6560¢ per kilowatt hour under present rates and 1.6976¢ per kilowatt hour under proposed rates. Although Rate Schedule OPT is a time-of-day rate which utilizes on-peak demand charges, economy demand charges, and on-peak and off-peak energy charges, CUCA contends that one can make reasonable inferences about the appropriate level of these charges from the available cost-of-service information.

CUCA argues that the variable costs "thrown off" by Duke's cost-of-service study are based upon average embedded variable costs; that Duke's average, embedded on-peak variable cost is greater than its average, embedded overall variable cost; and that the Company's average, embedded off-peak variable cost is less than its average, embedded overall variable cost. The off-peak summer and winter energy charges contained in Duke's present and proposed rate Schedule OPT are significantly above Duke's average, embedded overall variable costs, according to CUCA, which indicates that the Company is collecting a significant amount of fixed costs through the off-peak energy component of Rate Schedule OPT. By the same reasoning, the demand charges in Schedule OPT are below Duke's average, embedded fixed costs. CUCA contends that the recovery of a significant amount of fixed costs through the off-peak energy component of Rate Schedule OPT instead of through the demand charges in that same schedule is inconsistent with established rate design principles and renders Rate Schedule OPT insufficiently cost-based.

On cross-examination, witness Denton contended that proposed Rate Schedule OPT was designed on a marginal cost basis and that the present and proposed off-peak energy charges were appropriate in light of Duke's marginal costs. CUCA argues that Duke's overall revenues are determined on the basis of embedded rather than marginal costs; and that even if there is some justification for using marginal costs to design Rate Schedule OPT, Duke has not used marginal costing principles to design that rate in any consistent manner.

CUCA argues that the off-peak energy charges in Rate Schedule OPT are overstated even when considered on a marginal cost basis. During cross-examination, witness Denton testified that, even though Duke's cost-of-service study did not show marginal off-peak energy on its system, the Company did know its marginal energy costs. In support of this assertion, witness Denton pointed to the determinations made in this Commission's biennial avoided cost proceedings. In the most recent avoided cost proceeding conducted before this Commission, Duke proposed a variable off-peak energy credit of 1.86¢ per kilowatt hour. CUCA pointed out that the proposed variable off-peak energy credit is nearly 2/10 of a cent per kilowatt hour less than the current off-peak energy charge in the current Rate Schedule OPT and nearly 6/10 of a cent per kilowatt hour less than the off-peak energy charge in the proposed Schedule OPT.

CUCA contends that the requested overall rate increase results from changes in fixed costs. According to CUCA, the inclusion of increased fixed costs in the off-peak energy component of Rate Schedule OPT is inconsistent with the nature of the cost changes being experienced on Duke's system and with the results of its own cost-of-service study. CUCA believes that the off-peak energy charge in Rate Schedule OPT should be set at Duke's average embedded variable cost, and that the record contains no evidence justifying an increase in the off-peak energy charge of Rate Schedule OPT.

The Commission is of the opinion that the concerns regarding the appropriate proportion of fixed costs and variable costs to be included in demand charges and energy charges is directly related to the concerns regarding the appropriate cost allocation methodology discussed elsewhere herein. Until the matter of cost allocation is settled, it would be speculative to conclude that all fixed costs should be assigned to demand charges and that all variable costs should be assigned to energy charges. Although the Commission has adopted a particular cost allocation method for purposes of this proceeding, more discussion in future proceedings is needed before the issue can be considered reasonably settled. Accordingly, for purposes of this proceeding, the Commission concludes that the rate design proposed by the Company for Schedule OPT should be adopted, except as modified herein.

On-Peak Hours for Schedule OPT

The Company proposes to reduce the number of summer on-peak hours from ten to eight, with the on-peak period beginning at 1 p.m. and ending at 9 p.m. The reduction is proposed to make it easier for customers to shift production off-peak by allowing them to operate two eight-hour shifts during the off-peak period. NCIEC witness Baron and CUCA witness Phillips agreed with the proposed changes, and no other party expressed opposition to the modified hours. Therefore, the Commission concludes that the modified summer on-peak hours on Schedule OPT proposed by the Company should be adopted.

NCIEC witness Baron proposes that the Schedule OPT winter on-peak hours be reduced from 6 a.m. - 1 p.m. to 6 a.m. - 11 a.m. He contended that reducing the winter on-peak hours would result in better price signals. He acknowledged that he had not performed an analysis of the impact of his proposal.

The Commission is of the opinion that until further analysis the Company should not be required to reduce the number of on-peak hours during the winter months for Schedule OPT.

Demand Ratchets for Schedule I

CUCA raised the issue of billing demand ratchets in its filed briefs. CUCA pointed out that under Duke's present rate structure, Rate Schedule GA is available to both general service and industrial customers. Duke proposed in this proceeding to modify its rate schedules so that Industrial customers will be served on Schedule I, while general service customers will be served on Schedules G and GA. In order to implement this proposal, industrial customers currently served under Rate Schedule GA would be required to transfer to Rate Schedule I, although the billing demand provision of Rate Schedule GA would be maintained for industrial customers previously served under that rate schedule.

In order to accomplish this result, Duke proposed to revise the definition of "billing demand" in Rate Schedule I so that it reads as follows:

> A. For establishments served under this schedule where environmental space conditioning is required and all energy for all such conditioning (heating and cooling) is supplied electrically through the same meter as all other energy used in the establishment, the Billing Demand each month shall be the largest of the following:

1. The maximum integrated 30-minute demand measured during the month for which the bill is rendered.

2. Fifty percent of the maximum integrated 30-minute demand in the previous 12 months including the month for which the bill is rendered.

3. Fifty percent of the Contract Demand.

4. 15 kilowatts (kW).

NOTE: The minimum billing demand for contracts made prior to March 15, 1971, shall be 5 kW until the maximum integrated 30-minute demand becomes 15 kW, after which the minimum billing demand for such contract shall be 15 kW.

The Company will install a permanent demand meter for all customers meeting the requirements of A. above.

B. For all other customers served under this schedule, the Billing Demand each month shall be the largest of the following.

1. The maximum integrated 30-minute demand in the previous 12 months including the month for which the bill is rendered.

2. Fifty percent of the Contract Demand.

3. 30 Kilowatts (kW).

The Company will install a permanent demand meter when the monthly usage of the Customer equals or exceeds 3,000 kWh per month, or when tests indicate a demand of 15 kW or more. The Company may, at its option, install a demand meter for any customer served under B. above.

The actual tariff language of proposed Rate Schedule I does not limit the availability of the Billing Demand definition in subparagraph A to industrial customers previously served under Rate Schedule GA; instead, that definition of Billing Demand is available in all instances "where environmental space conditioning is required and all energy for such conditioning (heating and cooling) is supplied electrically through the same meter as all other energy used in the establishment." So long as a customer served under Rate Schedule I uses electricity for heating and cooling purposes, that customer's Billing Demand should be determined under subparagraph A regardless of whether that customer was previously served under Rate Schedule GA or Rate Schedule I.

CUCA contends that any Commission decision allowing Duke's request to transfer all industrial customers currently served under Rate Schedule GA to Rate Schedule I should insure that the definition of Billing Demand set forth in proposed Rate Schedule I is available to all customers served under Rate Schedule I. CUCA contends that the Commission should remove the 100% demand ratchet for 12 months from Schedule I, and that the industrial customers should not be subjected to differing definitions of billing demand depending on whether they use electricity for environmental space conditioning purposes. In short, the Commission should remove subparagraph B from Schedule I and require that all billing demand definitions be made under subparagraph A.

The Company did not address the concerns raised by CUCA in its filed brief. Under the circumstances, the Commission is of the opinion that the Company should be required to present testimony in its next general rate case addressing the justification for and use of the two tier demand ratchet in Schedule I. The Commission does make the observation here that the use of demand ratchets has been a controversial issue in previous proceedings, and that there has been less controversy since the availability of ratchet-free TOU rates to all customers as an alternative to those non-TOU rate schedules containing demand ratchets.

Summer/Winter Differential for Schedule GA

The Company proposes to merge Schedules G and GA by establishing identical rates for both rate schedules during the summer months. However, the Company proposes to establish a 5% differential between the rates for the two rate schedules during the winter months. The Company also proposes to move industrial customers from Schedule GA to Schedule I, leaving only general service customers on Schedule GA.

Witness Phillips testified that Schedule GA should not be closed to industrial customers, and that Schedule GA should be designed to reflect the actual costs of serving both general service and industrial customers.

Witness Turner testified that the cost allocation studies indicate that it costs as much or more to serve customers on all-electric Schedule GA as it does to serve customers on Schedule G. He contended that lower rates for Schedule GA should not be allowed without cost justification.

The Commission recognizes that it would be impossible to determine at this point what the results of a cost allocation study would be with industrial customers removed from Schedule GA. It also recognizes that the residential rate schedules already contain summer/winter differentials, even though the other nonresidential rate schedules do not. The Commission is of the opinion that the merger of Schedules G and GA during the summer months should be allowed, and that the summer/winter differential proposed for Schedule GA is consistent with other rate schedules for Duke and for CP&L and NC Power.

Interruptible Service Rider IS

Rider IS is the interruptible service rider under which general service and industrial customers receive a credit from Duke to curtail their load at Duke's request. Duke proposes to increase the cost to the customer in each situation where the customer does not interrupt his load at Duke's request. The current cost to the customer for failing to interrupt is $1.58/KW. Under the proposed revised Rider IS, each time the customer fails to interrupt, approximately one third of the credits paid to the customer during the year are to be repaid to

Duke. If a customer fails to interrupt three times during the year, all credits paid during the prior twelve months would be repaid to Duke and the customer would be removed from Rider IS. Witness Denton testified that this change will send a much stronger price signal to customers so that when Duke requests an interruption of load, the Company can expect customers to reduce their load to the level agreed to in their Rider IS contracts. Duke also proposes to make the exposure period consistent with Schedule OPT by reducing the exposure hours during the summer to equal the proposed summer on-peak hours.

No party objected to the proposed change in the penalty provision. However, CUCA witness Phillips proposes that the credit rate be increased from the present \$3.50/KW to a range of \$6.25/KW to \$7.50/KW per month. Duke witness Denton testified that the Company was attracting a sufficient amount of interruptible load at the present credit level and that an increase was not necessary. The Company has had to stop taking applications for the Rider because they are approaching the requested system cap of 1,100 megawatts.

CUCA contends that the long-term nature of interruptible service contracts implies that most current interruptible customers entered into such arrangements under the current credit and penalty structure; presumably, those customers accepted service under Rider IS after analyzing the rewards and penalties set forth in the current tariff. CUCA contends that Duke's proposal to increase the noninterruption penalty without increasing the capacity credit significantly alters the terms and conditions under which existing customers decided to take interruptible service. At the same time, the long-term nature of interruptible service contracts prohibits existing industrial customers from escaping the clutches of Rider IS in spite of this change in circumstances. For that reason, increasing the noninterruption penalty without increasing the corresponding credit is unfair to existing interruptible customers, according to CUCA.

The Commission is of the opinion that the modifications proposed by the Company for Rider IS should be approved, including the \$3.50 per kW credit. The Commission is mindful that the Company's past operating experience with interruptible customers suggests that such customers will rarely if ever be interrupted.

Multiple Energy Blocks

Witness Turner testified that the modified rate schedules proposed by the Company contain generally the same kWh blocking contained in the present rate schedules. In previous cases the Public Staff has expressed concern about whether these rate blocks reflect the cost of providing varying levels of kWh delivered to the customer and has taken the position that rates should not be blocked unless there is cost support for them. He stated that, if one assumes that the cost of energy is always the same or varies little compared to demand cost, then to justify the multiple energy block design proposed by Duke, one would have to know what the demand cost is by block or at various consumption levels. The cost-of-service study in its present form will only produce total customer, demand, and energy-related costs for the total class with no differential costs by level of kWh usage. Moreover, witness Turner stated he understands that this information is not known by the Company and cannot be provided. Without this cost support, he renewed his objection to the blocked rate design offered by Duke in this case and recommended that the Commission order Duke to provide cost support for the multiple block rate design. Without this support, Duke should eliminate multiple energy block pricing.

In connection with the Company's proposed rate design for general and industrial services rates, witness Turner also stated that the Company increased the number of energy blocks contained in Schedule G to minimize the trauma or rate shock associated with changing the pricing of Schedule G compared to Schedule GA. An additional 39,000 kWh group was added to the Next 275 hours use group. He stated that he has a problem with energy block charges absent cost justification and objected to the use of an additional block on a continuing basis, although he recognized that the additional block was added to minimize rate shock that would have otherwise resulted from the proposed design changes. He recommended that if the Commission concludes that the Company's proposed design changes to Schedule G and GA are appropriate, it should also require Duke to phase out this additional block when the Company files its next case and require Duke to provide justification from a cost standpoint for its block prices. Witness Turner stated that if the Commission decides the design change proposed by Duke for G and GA is not appropriate, then he would recommend that the additional block be eliminated in the approved rate schedules. Finally, he stated that for the same reasons explained in his discussion of the proposed residential energy blocks, he recommended that the Commission require Duke to provide cost support for the general service and industrial energy blocks and, without supporting cost data, require Duke to move toward the elimination of energy block pricing.

The Commission is of the opinion that energy block pricing should be supported by cost justification in general. However, there were a number of mergers and other rate schedule modifications proposed in this proceeding which make a systematic treatment of multiple energy block pricing difficult herein. Nevertheless, several prominent energy block features do present themselves for attention in this proceeding.

First, eliminating one of the energy blocks in Schedules RS1 thru RS 4 and Schedules RE1 thru RE2 can be accomplished in this proceeding relatively painlessly by merging the 950 kWh energy block and the over 1,300 kWh energy block for the winter season as a part of any reduction in the Company's proposed rates. The result would eliminate one of the energy blocks, create a more consistent summer/winter differential in the residential rates, eliminate the "hump" in the residential rate design, and reduce the water heater discount, all of which were objectives of previous Commission rate orders.

Second, eliminating one of the energy blocks in Schedules G and GA can be accomplished in this proceeding relatively painlessly by merging the proposed 95,000 kWh energy block and the proposed 39,000 kWh energy block in the 275 kWh per kW section of Schedules G and GA as a part of any reduction in the Company's proposed rates. The result would eliminate one of the energy blocks, and create a rate structure more consistent with industrial rates.

Third, the over 90,000 kWh energy block in the 125 kWh per kW section of Schedules G, GA and I needs attention. The energy block is applicable to large, low load factor customers, but it is priced lower than the energy block for high load factor customers in the over 400 kWh per kW section of the three rate schedules. The Commission is of the opinion that the Company should be required to present testimony with its next general rate case discussing the cost justification for the over 90,000 kWh energy block in the 125 kWh per kW section of Schedules G, GA and I.

General

Witness Denton described the changes Duke proposes for the Company's various rate schedules. The Company proposes to consolidate its three non-time-of-use residential rates into two new rate schedules: (1) RS, residential service; and (2) RE, all electric residential service. The proposed rate schedules eliminate present Schedules R, RC, and RA and reassign customers to new Schedules RS and RE. Schedule RS consists of four categories. Category 1 applies to any residential customer. Category 2 applies to residential customers with qualifying electric water heaters. Category 3 applies to residential customers meeting certain thermal conditioning requirements, including R-30 ceiling insulation, R-12 wall insulation, R-19 floor insulation, and storm windows. Category 4 applies to residential customers meeting both the requirements for categories 2 and 3. Schedule RE applies to residential customers where all energy required for water heating, cooking, clothes drying, and space conditioning is supplied electrically. Schedule RE consists of two categories. Category 1 applies to customers meeting specific requirements for electric water heaters and electric space conditioning. Category 2 applies to customers meeting the same specific thermal conditioning requirements as those required by Schedule RS, category 3 and 4. Witness Denton explained that the new rate schedules place customers in more homogeneous groups based on the equipment installed in their homes and permits targeted price signals to these homogenous groups.

Public Staff witness Turner agreed with the basic structure of the new residential rate schedules but expressed some concern that the energy block pricing for these rate schedules may not be appropriate. Witness Turner recommended that the Commission approve the new residential rate schedules proposed by the Company and require the Company to revise its cost allocation studies so that future cost studies show the cost of providing service to each of the new rate schedules.

Witness Denton also explained the proposed modifications to the general service and industrial rate schedules. Duke proposes to modify Schedules G, GA and I to eliminate the confusion caused by GA being available to both general service and industrial customers. He contended that under the current rate design, it is sometimes difficult for customers to determine the appropriate rate for their usage. The Company proposes that industrial customers be served on Schedule I, and that general service customers be served on Schedules G and GA. The billing demand provision of Schedule GA currently applied to industrial customers would be maintained for Schedule GA customers moving to Schedule I.

For general service customers, the Company proposes to retain Schedules G and GA with certain modifications. Under each rate schedule, the prices during April through November will be the same. The months of December through March will have lower energy charges for Schedule GA. The Company contends that the changes will reduce customer confusion in the general service class over which rate is more advantageous. Bills under Schedule GA will always be equal to or lower than bills under Schedule G.

Public Staff witness Turner agreed with the customer groupings on the modified non-residential rate schedules proposed by the Company, but expressed concern about the energy block pricing for these rate schedules.

Witness Denton also described the proposed changes to lighting rate schedules. The Company currently has four lighting rate schedules; Schedules T, T2, T2X, and FL. Schedule T, Street Lighting Service, is available to governments for public lighting. The Company proposes to change the name to Schedule PL, Street and Public Lighting Service. Schedule T2, Outdoor Lighting Service, would be designated Schedule OL. The designation of Schedule FL, Floodlighting Service, would not change.

The Company is proposing additional pricing levels for Schedules OL and FL to cause new customers to pay the higher cost of installing lights when a pole installation is requested by the customer. The proposed rates include pricing for a new luminaire on an existing pole, for the installation of a new pole, and a price for a new pole installation and underground service. Existing installations would be served on the luminaire-only rate. Schedule T2X, Subdivision Entrance Lighting Service, is currently available for lighting entrances to subdivisions and other public areas. The Company is proposing to cancel Schedule T2X and offer new mercury vapor and high pressure sodium vapor post-top luminaires on Schedule OL.

Other highlights of rate design changes proposed by the Company and unopposed by any party include: (1) increased reconnect fees from $5.00 to $15.00; (2) increased return check charges from $5.00 to $15.00; (3) addition of a new pilot program for up to 20 customers in which demands incurred during Company designated off-peak periods will not be reflected in monthly demand charges (named Limited Demand Charge Day service); (4) new length of contract terms for all lighting rate schedules at three years, 10 years or 20 years; and (5) miscellaneous administrative clarifications, renaming of rate schedules, and restructuring of paragraphs in the tariffs and the terms and conditions of service. On July 30, 1991, the Commission approved Rider LDCD implementing the new pilot program.

The Commission concludes that the rate designs, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company herein are appropriate and should be adopted, except as specifically modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 143 - 145

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Stimart and Public Staff witness Maness and in Docket No. E-7, Sub 408.

At the time of the Company's last rate case, Docket No. E-7, Sub 408, Duke had an ongoing dispute with the North Carolina Department of Revenue as to the level of Duke's property taxes for 1985, the test year in that case. Duke adjusted its North Carolina property taxes based on the Department of Revenue's position on the assessed value of Duke's property in North Carolina. However, Duke remitted to the State, and expensed on its books, an amount for property taxes based on the Company's proposed value of its North Carolina property. The

Company's proposed property value was lower than the State's assessed value. The Public Staff testified that if the dispute was ultimately determined in the Company's favor, Duke would have collected in rates an amount for property taxes which would be greater than the amount incurred. Duke agreed to refund the excess property taxes in such an event, and the Commission's Order in the last case required the Company to place certain potential excess property taxes collected in a deferred account subject to refund.

In this rate case, Public Staff witness Maness testified that a settlement was reached between Duke and the Department of Revenue which resulted in Duke paying $2,660,000 of the $3,429,000 of property taxes in dispute for 1985. Witness Maness recommended that the excess property taxes collected by Duke be refunded to ratepayers with interest in one year through a rider.

Company witness Stimart testified that no refund for excess property taxes should be made. He testified that the issue in Duke's dispute with the Department of Revenue concerned the treatment of accumulated deferred income taxes (ADIT) in determining the assessed property value and that Duke withdrew its challenge on that issue and reached a settlement on another issue. He testified, "We lost the issue that was under consideration in the last case, but, as a rebound to that, we said, well, how about giving us a change in the way you weight the components in determining valuation. . . we got some savings out of them but not on the issue that was before the Commission back in '86." Another reason cited by witness Stimart for not refunding the excess property taxes collected was that Duke's property taxes were 37 percent higher at the time of this hearing than they were in 1985. Witness Stimart also testified that if the Commission agreed with the Public Staff, the amount should be used to reduce the cost of service, rather than being refunded through a rider.

In response to a discovery request asking how the property tax assessment dispute was resolved, Duke responded in part, "The Company contested these rates, ultimately settling with the N. C. Department of Revenue. As a result of the settlement, the Company paid an additional $2,660,367 of the $3,429,000 of protested property taxes for 1985." Public Staff-Stimart Rebuttal Exhibit 2 Late Filed. The Commission finds, from this exhibit and from witness Stimart's testimony as quoted above, that the dispute which prompted the deferred account in Duke's last rate case led to negotiations that resulted in a settlement and that the settlement resulted in Duke paying less property tax for 1985 than the level reflected in the rates approved in that case. The Commission concludes that the settlement does come within the terms of refund provided in the Commission's Order in Docket No. E-7, Sub 408. Further, the Commission concludes that the fact property taxes today are higher than they were in 1985 is not persuasive. As the Company adds new customers, additional plant investment is necessary. Additional plant would increase the property tax valuation which would result in higher property taxes being assessed. However, the additional customers would result in additional revenues, a portion of which is designed to recover property taxes. Even if the Company suffered some net revenue erosion, it would be retroactive ratemaking to award the Company revenues in this case for that revenue erosion.

Based on the foregoing, the Commission concludes that the Company should refund to its customers the excess property tax expense approved in its last general rate case, Docket No. E-7, Sub 408, as provided in the Commission's Order in that proceeding. This refund should take the form of a decrement rider in the amount of .00716 cents/kWh, such rider to be effective for approximately one year beginning with the effective date of this Order, modified as required so as to refund as practically as possible the total overcollection of $2,907,000. The Commission decision on this refund has the effect of placing the Company and the ratepayers in the same position as if the property tax dispute had been settled before the Commission issued its Order in the Company's last general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke Power Company is hereby authorized to adjust its electric rates and charges effective with the date of this Order so as to produce an increase in gross annual revenue from its North Carolina retail operations of $100,072,000 based upon the adjusted test year level of operations.

2. That the Company shall replace the current base fuel factor of 1.1665¢/kWh without gross receipts tax, or 1.2053¢/kWh including gross receipts tax, approved in general rate case Docket No. E-7, Sub 408, with the new base fuel factor of 1.1032¢/kWh without gross receipts tax, or 1.1399¢/kWh including gross receipts tax, approved in this proceeding.

3. That within five working days after the date of this Order, the Company shall file with the Commission five copies of its retail service rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines contained herein. The rate schedules required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

4. That within ten working days after the date of this Order, the Company shall file with the Commission five copies of computations showing the overall North Carolina retail rate of return and the rate of return for each rate schedule which will be produced by the revenues approved by this Order. Such computations shall be based on the cost allocation methodology approved herein, and on the current customer classes.

5. That the Company shall give appropriate notice of the rate increase approved herein by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the new rate schedules required herein. The Company shall submit its proposed customer notice to the Commission for approval before mailing the notice to customers.

6. That the Company shall revise its future fully distributed cost allocation studies to reflect the cost of service to its major customer classes adopted herein, including but not limited to the following: RS1, RS2, RS3, RS4, RE1, RE2, G, GA, OPT General, PL, OL, TS, I, and OPT Industrial. The revised cost allocation studies shall be filed with the Commission annually on or before April 30 using the Summer/Winter Peak and Average methodology and the Summer Coincident Peak methodology.

7. That the Company shall prepare cost allocation studies for presentation with its next general rate case which allocate production plant based on the Summer/Winter Peak and Average methodology and the Summer Coincident Peak

methodology. The studies shall be included in item 45 of Form E-1 of the minimum filing requirements for a general rate application.

8. That the Company shall prepare testimony for presentation with its next general rate case which addresses the justification for and the use of the two tier billing demand ratchet in Rate Schedule I.

9. That the Company shall prepare testimony for presentation with its next general rate case which addresses the cost justification for the over 90,000 kWh energy block in the 125 kWh per kW section of Rate Schedules G, GA and I, and particularly why the price level of said energy block should be lower than the price level in the energy block of the over 400 kWh per kW section of each respective rate schedule.

10. That the company shall monitor the system loads on Martin Luther King Day in order to determine if or when it should be included with other off-peak holidays. The Company shall prepare testimony for presentation with its next general rate case which addresses the status of its ongoing review of the system loads on Martin Luther King Day.

11. That within six months after the date of this Order, the Company shall file with the Commission a report on the feasibility of providing periodic information to residential TOU customers regarding the savings (or loss) for the TOU rates versus non-TOU rates.

12. That the Company shall cease collecting funds from its residential customers for the Residential Loan Assistance Program account. The Company shall report to the Commission on the need for resuming funding of the RLAP account at such time as the Company determines the need for such resumed funding.

13. That the Company shall be allowed to fund other residential DSM programs out of the Residential Loan Assistance Program account, provided it first obtains Commission approval of specific uses of funds from the account.

14. That the Company shall include the Residential Loan Assistance Program in future analyses of its Least Cost Integrated Resource Plan for evaluation as a DSM resource option.

15. That the Company shall modify its proposed comparative billing program for residential customers to include its residential all-energy TOU rate schedule. The comparative billing program may still be limited to 1,000 customer volunteers at a time.

16. That the Company shall continue to offer its all-energy TOU rate schedule to its residential customers, and that it shall remove the term "experimental" and any other reference in the rate schedule or literature discussing the rate schedule that refers to the rate schedule as anything other than a permanent rate offering.

17. That the Stipulation between the Company and the Public Staff regarding DSM cost recovery, filed with the Commission on September 9, 1991, in Docket Nos. E-100, Sub 58, and E-7, Sub 487, is hereby approved as described herein. A copy of the Stipulation is attached to this Order as Appendix 1.

18. That the Company shall file quarterly reports with the Commission showing the status of and activity in the DSM deferred account established herein pursuant to the Stipulation regarding DSM cost recovery. These reports shall be filed no later than 60 days from the close of each calendar quarter.

19. That the percentage increase applied to each major rate class in this proceeding shall be the same percentage for all rate classes, except for Rate Schedules GB, GT and IT.

20. That the percentage increase applied to Rate Schedules GB, GT and IT shall be two percentage points greater than the percentage increase applied to the respective alternative rate schedules.

21. That fifty percent of the proposed $4,046,000 adjustment for a revenue shortfall due to customer migration among the various rate schedules shall be recovered from the rate classes responsible for the shortfall, and fifty percent shall be recovered from all rate classes in proportion to the revenue requirement for each rate class. The proposed $4,046,000 adjustment shall first be modified to reflect the difference between the Company's proposed revenue requirements and the revenue requirements actually approved herein.

22. That any revenue shortfall due to the designation of additional off-peak holidays herein shall be recovered from the rate schedules responsible for the shortfall.

23. That the revenue adjustments for customer growth and for weather normalization shall be incorporated into the revenue requirements for each rate schedule as applicable. Said revenue adjustments shall first be modified to reflect the difference between the current revenues and the revenue requirements actually approved herein.

24. That miscellaneous service charges shall be established at the levels proposed by the Company.

25. That the rate designs, rate schedules, miscellaneous charges, and terms and conditions of service proposed by the Company, except as modified in this Order, are hereby approved.

26. That the Company shall designate as off-peak periods, in addition to the six holidays proposed by the Company for Rate Schedule RT, Good Friday and the Friday after Thanksgiving. The resulting eight holidays shall also be designated as off-peak periods for Rate Schedules RTX and OPT.

27. That the Company shall establish the same price level for the 950 kWh energy block and the over 1,300 kWh energy block for the <u>winter</u> season in Rate Schedules RS1 thru 4 and RE1 thru 2.

28. That the Company shall establish the same price level for the 39,000 kWh energy block and the 95,000 kWh energy block in the 275 kWh per kW section of Rate Schedules G and GA.

29. That all TOU rate schedules shall be designed to be revenue neutral with corresponding non-TOU rate schedules.

30. That individual prices calculated in accordance with the rate design guidelines contained herein may be rounded off to the extent necessary for administrative efficiency, provided said rounded off prices do not produce revenues which exceed the overall revenue requirement established by the Commission herein.

31. That the Company shall implement an across-the-board decrement rider in the amount of .00716¢/kWh, to be effective for approximately one year beginning with the effective date of this Order, for the purpose of refunding to its customers the excess property tax expense approved in Docket No. E-7, Sub 408. This rider shall be modified during the final month(s) of the refund period as required so as to refund as practicably as possible the overcollection of this cost in the amount of $2,907,000. This rider shall terminate when the refund process is complete. Within 30 days of the termination of this rider, Duke shall file with the Commission a report setting forth the amount refunded and the period over which this refund was accomplished.

32. That the Company shall place all proceeds - whether payments, damages or settlement - realized as a result of Schedule J in a deferred account. The deferred account shall accrue carrying costs net of tax at the then applicable allowed rate of return, and the balance shall be refunded to customers in a manner to be prescribed by further order of the Commission

33. That Duke's Louisiana Energy Services (LES) venture is a nonutility venture which should be funded by Duke's shareholders and not its North Carolina retail ratepayers. Therefore, the costs identified with this venture as described herein shall be charged to Duke's nonutility accounts and shall be borne by the Company's shareholders and not its North Carolina retail ratepayers.

ISSUED BY ORDER OF THE COMMISSION.
This the 12th day of November 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX 1

BEFORE THE
NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-100, SUB 58
DOCKET NO. E-7, SUB 487

In the Matter of
Analysis and Investigation of Least)
Cost Integrated Resource Planning)
in North Carolina)

In the Matter of
Application of Duke Power Company)
for Authority to Adjust and)
Increase its Electric Rates and)
Charges)

STIPULATION BETWEEN DUKE POWER COMPANY AND THE PUBLIC STAFF DEMAND-SIDE MANAGEMENT (DSM) COST DEFERRAL

DOCKET NO. E-07, SUB 487
DOCKET NO. E-100, SUB 58

STIPULATION BETWEEN THE PUBLIC STAFF AND DUKE POWER COMPANY

Duke Power Company filed a cost recovery plan pursuant to a Commission order with the Commission in Docket No. E-100, Sub 58. The Public Staff filed comments on Duke's plan on August 16, 1991. Negotiations have been on-going in an attempt to reach a settlement including the utilization of a deferred account. The parties have reached the following agreements. Accordingly, this document is submitted as a stipulation between Duke and the Public Staff with respect to issues in controversy in both of the designated dockets. Duke and the Public Staff respectfully request that the Commission enter appropriate orders approving this stipulation.

DEMAND-SIDE MANAGEMENT (DSM) COST DEFERRAL

Beginning on January 1, 1992, the Commission will allow the Company to defer certain DSM program costs associated with DSM programs (programs that have as their objective conservation and load reduction) that have been formally approved by the Commission in conjunction with the Company's least cost integrated resource planning process as described in N.C.G.S. 62-2(3a). The costs to be deferred associated with already approved programs are load control credits, credits for interruptible service, incentive payments, standby generator payments, and advertising which consists of media and printed material. Amounts spent on advertising a DSM program will be at a reasonable level in light of the program's anticipated economic benefit. At the time the Company seeks approval of new or modified DSM programs, the Company will enumerate the nature of the costs contemplated to be deferred as a part of obtaining Commission approval. As an offset, the Company will credit the deferred account for the corresponding DSM costs recovered from ratepayers. The costs recovered from ratepayers will be calculated on a ¢/kWh basis times actual kWh sales. To calculate the ¢/kWh factor, the equation shown on Appendix A shall be completed by inserting Commission approved amounts for N.C. retail demand factor and N.C. retail MWH sales.

At the time rewards are recognized pursuant to N.C.G.S. 62-2(3a), the amount of these rewards will be added to the deferred balance.

If Duke seeks recovery of revenue losses when it seeks Commission approval to implement a DSM program, the burden shall be on Duke to show a net revenue loss from the program. In determining the net revenue loss, Duke agrees to offset its revenue losses with "found" sales revenues, not previously used to offset other losses, attributable to its load balancing (e.g., valley filling) programs. The parties propose that the Commission should approve an estimate of lost sales revenues, if any, before the program is implemented. Duke will then check the accuracy of these estimates as it performs its program evaluations.

A return on the deferred balance is computed monthly and added to the balance. Interest will be compounded annually. The rate of return will equal the net of tax rate of return approved by the Commission in Docket No. E-7, Sub 487 or subsequent rate cases. The balance in the deferred account will be reflected in Duke's next rate case by amortizing the then existing balance over a period of three to five years, except the Commission may order a longer period if the amount in the deferred account would have a significant impact on rates.

This the 9th day of September 1991.

DUKE POWER COMPANY
D. H. Denton, Jr.
Senior Vice President
Planning and Operations

PUBLIC STAFF, NORTH CAROLINA
UTILITIES COMMISSION
Robert P. Gruber
Executive Director

APPENDIX A
Duke Power Company - Docket No. E-7, Sub 487
Demand Side Program Costs
Amount Included In Cost of Service
As the Basis For The Deferral Account
(Thousands of Dollars)

Equation for Determining ¢/KWH Credit to Demand Side Cost Deferral Account

$$\frac{30{,}622{,}137^{(3)} \times \text{N.C. Retail Demand Factor}^{(1)}}{\text{N. C. Retail MWH Sales}^{(2)}} = ¢/\text{KWH}$$

(1) Company filed based on 62.2062%
(2) Company filing reflected 40,619,162 MWH.
(3) Consists of the following amounts:

Annualized costs at December 31, 1990:		
Credits for Interruptible Service	ND-143	$ 6,421,348
Credits for Load Control	"	12,582,296
Payments for Standby Generation	"	558,655
Advertising Costs		2,140,888
Subtotal		21,703,187
Costs for Expansion of Demand Side Programs Included in Cost of Service (1991 Level):		
Credits for Interruptible Service	ND-1400	1,604,925
Credits for Load Control	"	1,833,653
Payments for Standby Generation	"	292,349
Advertising Costs	"	2,883,431
Incentive Payments	"	2,304,592
Subtotal		8,918,950
Total costs of demand side programs to be credited to the deferred account		$30,622,137

DOCKET NO. E-22, SUB 314
DOCKET NO. E-22, SUB 319

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Request of North Carolina Power for Authority to Adjust Its Electric Rates and Charges and Application of North Carolina Power Pursuant to G. S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	ORDER APPROVING PARTIAL RATE INCREASE

HEARD: Wednesday, November 7, 1990, at 7:00 p.m., Council Chambers, Town Hall, 201 West Main Street, Ahoskie, North Carolina

Wednesday, November 7, 1990, at 7:00 p.m., Courtroom B, Pasquotank County Courthouse, Elizabeth City, North Carolina

Thursday, November 8, 1990, at 7:00 p.m., Assembly Room, City Hall, Main Street, Williamston, North Carolina

Thursday, November 8, 1990, at 7:00 p.m., Banquet Hall, Roanoke Rapids Community Center, 1100 Hamilton Street, Roanoke Rapids, North Carolina

Thursday, November 15, 1990, at 7:00 p.m., in the Main Courtroom, Dare County Courthouse, 300 Queen Elizabeth Avenue, Manteo, North Carolina

Tuesday, November 27, 1990, at 9:30 a.m., through Friday, November 30, 1990, and Tuesday, December 4, 1990, through Thursday, December 6, 1990, in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Chairman William W. Redman, Presiding; Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, Robert O. Wells, Charles H. Hughes and Laurence A. Cobb

APPEARANCES:

For North Carolina Power:

Edgar M. Roach, Jr., and Edward S. Finley, Jr., Hunton & Williams, Attorneys at Law, Post Office Box 109, Raleigh, North Carolina 27602

and

James S. Copenhaver, North Carolina Power, Post Office Box 26666, Richmond, Virginia 23261

For the Public Staff:

Paul L. Lassiter, James D. Little, Vickie L. Moir, and Gisele L. Rankin, Staff Attorneys, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

For Carolina Industrial Group for Fair Utility Rates (CIGFUR-I):

Ralph McDonald and Carson Carmichael, III, Bailey and Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605-2865

For Carolina Utility Customers Association, Inc. (CUCA):

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon, Ervin and Sanders, P.A., Post Office Drawer 1269, 301 East Meeting Street, One Northsquare Building, Morganton, North Carolina 28655

BY THE COMMISSION: On May 31, 1990, North Carolina Power (also referred to as Virginia Electric and Power Company, VEPCO, Applicant or Company) filed an application with the North Carolina Utilities Commission in Docket No. E-22, Sub 314 seeking authority to adjust and increase its rates and charges for electric service to its North Carolina retail customers to become effective on July 1, 1990. By letter dated June 11, 1990, the Company waived its right to place the proposed rates into effect pursuant to G.S. 62-135 until February 1, 1991.

On June 26, 1990, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, requiring public notice, and scheduling public hearings in Ahoskie, Elizabeth City, Williamston, Roanoke Rapids, and Raleigh. The Commission subsequently scheduled a public hearing in Manteo.

As provided by Commission Rule R8-55, North Carolina Power's annual fuel charge adjustment application was due to be filed on September 14, 1990, and a hearing held on November 13, 1990. Docket No. E-22, Sub 319 had been reserved for North Carolina Power's 1990 fuel charge adjustment proceeding.

On July 16, 1990, North Carolina Power filed a Motion for Consolidation of Hearings in the above captioned dockets. By its Motion, North Carolina Power asserted that it intended to file supplemental data updating its testimony in the general rate case with respect to fuel costs and the fuel component of purchased power consistent with the test period required for its fuel charge adjustment proceeding, which was the twelve-month period ending June 30, 1990. North Carolina Power therefore proposed that the hearing in its fuel charge adjustment proceeding be rescheduled and consolidated with the general rate case hearing scheduled to begin in Raleigh on November 27, 1990.

On July 25, 1990, the Public Staff filed a letter asserting that it had no objection to the consolidation provided that no order be issued in the fuel charge adjustment proceeding until all evidence in that proceeding had been heard.

On August 2, 1990, the Commission issued an Order consolidating the hearings for the fuel charge adjustment proceeding and the general rate case. In that Order, the Commission provided that it would rule on the Experience Modification Factor (EMF) related issues in the fuel charge adjustment proceeding in order to allow for an effective date of the billing month of January 1991. However, the Commission indicated that it would defer ruling on the other issues in the fuel charge adjustment proceeding until the issuance of the general rate case Order. The Commission provided for a consolidated public notice by Order of September 26, 1990.

On September 17, 1990, the Carolina Industrial Group for Fair Utility Rates filed a Petition to Intervene, which was allowed by Commission Order dated September 19, 1990.

On October 3, 1990, the Carolina Utility Customers Association, Inc., filed a Petition to Intervene, which was allowed by Commission Order dated October 8, 1990.

On November 8, 1990, the Attorney General filed a Notice of Intervention pursuant to G.S. 62-20 on behalf of the using and consuming public.

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

<u>Ahoskie:</u>	John Gaitten Garth Faile
<u>Elizabeth City:</u>	Lucy Gordon Gwendlyn Jones Ulysses Bell
<u>Williamston</u>:	Roger A. Critcher, Jr. Ollie Manning Linwood Boyd
<u>Roanoke Rapids</u>:	Rex H. Carter Marshall Grant Roland Whitted
<u>Manteo:</u>	(No witnesses)
<u>Raleigh</u>:	Rex H. Carter John Moulton Lester Teal

The expert testimony was heard in Raleigh beginning November 27, 1990.

The Applicant presented the testimony and exhibits of the following witnesses: James T. Rhodes, President and Chief Executive Officer of Virginia Electric and Power Company; Dr. William E. Avera, a principal in Financial Concepts and Applications, Inc.; Henry W. Zimmerman, Manager-Planning for Virginia Electric and Power Company; M. Stuart Bolton, Jr., Manager-Regulatory Accounting for Virginia Electric and Power Company; and Andrew J. Evans, Director-Rate Design for Virginia Electric and Power Company.

The Applicant also introduced the affidavits and exhibits of Henry Leidheiser, III, Assistant Treasurer at Virginia Electric and Power Company and William G. Fitch, Jr., Supervisor-Depreciation and Project Analysis for Virginia Electric and Power Company.

The Public Staff presented the testimony and exhibits of the following witnesses: Kevin W. O'Donnell, Financial Analyst, Economic Research Division of the Public Staff; James S. McLawhorn, Electric Engineer, Electric Division of the Public Staff; Benjamin R. Turner, Jr., Electric Engineer, Electric Division of the Public Staff; Thomas S. Lam, Electric Engineer, Electric Division of the Public Staff; Katherine A. Fernald, Staff Accountant, Accounting Division of the Public Staff; and Michael C. Maness, Supervisor, Accounting Electric Section, Accounting Division of the Public Staff.

CIGFUR presented the testimony and exhibits of the following witnesses: Nicholas Phillips, Jr., principal in the firm of Drazen-Brubaker & Associates, Inc.; George Gillespie, Manager of Energy Purchasing with Abbott Laboratories; and John P. Murphy, Director of Energy Supply for Champion International.

The Applicant presented the rebuttal testimony of the following witnesses: Mary C. Doswell, Director, Demand-Side Analysis for Virginia Electric and Power Company; Andrew J. Evans; William E. Avera; Henry W. Zimmerman; and M. Stuart Bolton, Jr.

The Company requested that the hearing in the general rate case be kept open until the date two non-utility generating facilities, Panda-Rosemary and Richmond Power Enterprises (RPE), were estimated to declare commercial operations. The parties present entered into a stipulation under which the hearing would remain open at least until December 15, 1990, but no later than either the filing date of an affidavit by the Company indicating that Panda and RPE had declared commercial operations or January 15, 1991, whichever one occurred first. Further, if these two facilities declared commercial operations by December 15, 1990, the date on which increased rates under bond could be put into effect would be February 1, 1991. If they did not declare commercial operation by the December 15, 1990, deadline, there would be a day-by-day extension of the close of the hearing and the date on which proposed rates could go into effect under bond until the January 15, 1991, deadline for the close of the hearing and March 4, 1991, for the proposed rates under bond.

By affidavit of Larry W. Ellis, Senior Vice-President of Power Operations and Planning, filed December 28, 1990, the Company notified the Commission and the parties of record that the Company recognized commercial operations for the Panda-Rosemary facility as of December 27, 1990. By letter dated December 28, 1990, the Company informed the Commission that it believed RPE would not be in commercial operation prior to January 15, 1991. The Company, therefore, requested that the hearing officially be closed as of December 28, 1990.

The Commission issued its Order Closing Hearing on January 3, 1991, declaring the hearing closed as of December 28, 1990, and setting certain dates for filings. Pursuant to the above-described stipulation, the Company waived its right to put its rates in effect under bond until February 14, 1991.

Proposed orders and briefs were filed as provided by the Commission's Order Closing Hearing of January 3, 1991. Thereafter, on January 28, 1991, the Public Staff filed Response of Public Staff to Company's Proposed Order. On February 1, 1991, the Company filed Response of North Carolina Power to Arguments of Intervenors. Finally, on February 8, 1991, the Attorney General filed Attorney General's Request to Reply to North Carolina Power. These three filings were not provided for by the Commission's January 3, 1991, Order. The responses of the Public Staff and the Company are stricken from the record, and the request of the Attorney General is denied. The Commission has not considered these filings in making its decisions herein.

Prior to and during the course of the hearings, the parties made various motions and the Commission entered various Orders, all of which are matters of record. Additionally, pursuant to Orders of the Commission or requests of the parties, also of record, certain parties were directed or permitted to submit late-filed exhibits either during or subsequent to the hearings.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearing, the proposed orders and briefs submitted by the parties, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. Virginia Electric and Power Company is duly organized as a public utility operating under the laws of the State of North Carolina and is subject to the jurisdiction of the North Carolina Utilities Commission. The Company is engaged in the business of developing, generating, transmitting, distributing, and selling electric power to the public in northeastern North Carolina. North Carolina Power is an unincorporated division of Virginia Electric and Power Company and has its office and principal place of business in Richmond, Virginia. Virginia Electric and Power Company is a wholly owned subsidiary of Dominion Resources, Inc.

2. North Carolina Power is lawfully before this Commission based upon its application for a general increase in its retail rates pursuant to G.S. 62-133 and for an adjustment in its fuel costs pursuant to G.S. 62-133.2.

3. The test period for purposes of the general rate case proceeding (Docket No. E-22, Sub 314) is the 12-month period ended December 31, 1989, adjusted for certain known changes based upon circumstances and events occurring up to the close of the hearing.

4. North Carolina Power by its general rate case application (Docket No. E-22, Sub 314), sought an increase in its basic rates and charges to its North

Carolina retail customers of $23.4 million consisting of an increase of $25.1 million in annual basic non-fuel revenues, a return to ratepayers of $4.6 million in accumulated excess deferred taxes, and an increase in the fuel component of $2.9 million.

5. The overall quality of electric service provided by North Carolina Power to its North Carolina retail customers is good.

6. The Summer/Winter Peak and Average method is the most appropriate method for allocating costs between jurisdictions and between customer classes within the North Carolina retail jurisdiction in this proceeding. Consequently, each finding in this Order which deals with the overall level of rate base, revenues and expenses for North Carolina retail service has been determined based upon the Summer/Winter Peak and Average cost allocation methodology as described herein.

7. The Company has chosen to meet most of its near-term load growth in its service territory by obtaining significant amounts of new capacity and energy through competitive solicitations for non-utility generation (NUG). By the time of the hearing in this docket, this had resulted in the purchase of approximately 900 mW of capacity and energy on an annual basis from non-utility generators, which has been increased by 150 mW in the summer and 185 mW in the winter by the declaration of commercial operations by Panda-Rosemary Corporation on December 27, 1990.

8. After subtracting the approximately 654 mW the Company no longer has a legally enforceable right or obligation to purchase because of terminated contracts or defaults by developers, additional purchases of approximately 2633 mW have been contracted for over the next seven years. Approximately 248 mW is expected to come on-line in 1991, which will be increased by the 210/240 mW associated with the delayed Richmond Power Enterprises project, if RPE declares commercial operations prior to its June 1, 1991, default date. A total of 1058 mW is expected to come on-line in 1992. The Company's proposal to recover these and other future non-utility generation expenses through purchased capacity and purchased energy riders outside of the framework of a general rate case is rejected.

9. The Company should consistently use the most current retirement dates in calculating both depreciation rates and theoretical reserves in its depreciation studies.

10. The $238,194 North Carolina jurisdictional depreciation adjustment to the steam unit accounts proposed by the Public Staff is appropriate in this proceeding.

11. The correct depreciation rate to be used for the Bath County Pumped Storage Facility accounts is 2.00%.

12. The $8,248 North Carolina jurisdictional depreciation adjustment to the Bath County accounts proposed by the Public Staff is appropriate in this proceeding.

13. The appropriate level of materials and supplies for use in this proceeding is $11,510,000.

14. No amount representing a deferred fuel underrecovery should be included in working capital.

15. The prepaid pension settlement of $726,000 should be excluded from working capital.

16. For purposes of this proceeding, accounts payable related to construction and nuclear fuel in the amount of $1,343,000 should be deducted from working capital.

17. No amount representing unamortized Surry outage costs should be included in working capital.

18. No amount representing unamortized sales and use tax assessment costs should be included in working capital.

19. The appropriate level of cash working capital investment for use in this proceeding is $3,393,000.

20. It is appropriate in this proceeding to make an adjustment to per books accumulated depreciation in the same amount as the amount added to per books depreciation expense as an annualization adjustment.

21. The proper level of accumulated depreciation for use in this proceeding is $131,522,000.

22. North Carolina Power's reasonable original cost rate base used and useful in providing service to its North Carolina retail customers is $330,403,000, consisting of electric plant in service (including nuclear fuel) of $504,804,000, materials and supplies of $11,510,000, and cash working capital of $3,393,000, reduced by accumulated depreciation of $131,522,000, accumulated amortization of nuclear fuel of $25,084,000, accumulated deferred income taxes of $32,488,000, and other cost-free capital of $210,000.

23. The appropriate level of test year North Carolina jurisdictional sales is 2,352,284 mWh.

24. The appropriate level of unbilled test year sales is 26,592 mWh.

25. The appropriate level of basic rate schedule revenues based on rates in effect January 1, 1990, is $114,859,301.

26. The appropriate level of basic revenues related to unbilled mWh sales is $1,353,048.

27. The appropriate end-of-period level of revenues for load management credits is $(132,151).

28. The appropriate level of end-of-period revenues related to facilities charges is $362,344.

29. The appropriate level of end-of-period revenues related to miscellaneous service charges is $717,562.

30. The appropriate level of revenues associated with growth, usage, and weather is calculated by multiplying the total kWh adjustment by average customer class rates based on annualized revenues and test year kWh sales.

31. The adjustments related to weather normalization, customer growth, and increased usage, are appropriate for use in this proceeding, for the 12-month test period through the update period ending September 30, 1990, are (4,617) mWh, 48,528 mWh, and 52,007 mWh, respectively, for a total of 95,918 mWh.

32. The basic revenues related to weather normalization, customer growth, and increased usage for the test year through the update period ending September 30, 1990, is $4,738,524

33. The adjusted level of sales for the test year through the update period ending September 30, 1990, is 2,474,794 mWh.

34. The basic revenues related to growth in load management credits for the test period through the update period ending September 30, 1990, is $(30,690).

35. Total adjusted rate schedule revenues for the test period through the update period ending September 30, 1990, are $120,950,873.

36. For the test period through the update period ending September 30, 1990, total basic adjusted revenue, excluding other miscellaneous revenue, is $121,867,938 based on the sum of adjusted rate schedule revenues of $120,950,873, less load management credits of $162,841, plus revenue derived from facilities charges of $362,344, plus miscellaneous service revenue of $717,562.

37. The proper level of gross revenues for North Carolina Power for the test year (excluding fuel revenue), under present rates and after accounting and pro-forma adjustments, is $122,356,000.

38. It is appropriate to adopt the accrual method of accounting for other post-retirement benefits (OPRB).

39. In accruing other post-retirement benefits the attribution period should be measured from the date of hire to date of full eligibility for other post-retirement benefits.

40. It is inappropriate to include $31,000 in operating revenue deductions for Three Mile Island contribution expense.

41. The net Public Staff adjustment of $(20,000) to non-utility generation expense relating to the customer growth component of non-utility generation expense is reasonable for purposes of this proceeding.

42. The net Public Staff adjustment of $3,000 to non-utility generation expense relating to capacity revenue offset component of non-utility generation expense is reasonable for purposes of this proceeding.

43. The total net Public Staff adjustment of \$(17,000) to non-utility generation expense is reasonable for purposes of this proceeding.

44. The Public Staff adjustment to exclude \$14,000 from expenses, representing 50% of the North Carolina retail portion of the compensation of the officers most closely linked with meeting the demands of the Company's common stockholder, is reasonable and appropriate for purposes of this proceeding.

45. It is appropriate to amortize the gain recognized by the Company in 1988 due to the settlement of pension obligations (the Equitable settlement) over the period of time that such gain would have been amortized had no settlement occurred. This results in an adjustment of \$(30,000) to the Company's recommended fringe benefits expense level.

46. It is appropriate to amortize the 1988 and 1989 Surry outage costs over a period of three years.

47. The \$71,000 of accelerated depreciation expense relating to the North Anna Unit 1 steam generators proposed by the Company should be included in expenses in this proceeding.

48. The Public Staff adjustment of \$(137,000) to reallocate the North Anna Unit 3 loss amortization is reasonable and proper for purposes of this proceeding.

49. It is appropriate, for purposes of this proceeding, to remove the remaining North Anna Unit 4 loss amortization of \$308,000 from operating revenue deductions.

50. It is appropriate, for purposes of this proceeding, to include a portion of the remaining North Anna Unit 4 loss amortization as an offset to the excess deferred income tax refund approved herein.

51. The Public Staff adjustment to reclassify state income taxes of \$53,000 from the "Other taxes" category to the "Income taxes" category is reasonable.

52. No amount relating to the prior years' Virginia sales and use tax assessment should be included in operating revenue deductions in this proceeding. The Public Staff adjustment of \$(76,000) is appropriate.

53. Based on the other findings and conclusions set forth in this Order, the appropriate level of income tax expense under present rates for use in this proceeding is \$7,184,000.

54. The charitable contributions of \$70,000 included by the Company in operating revenue deductions should be excluded.

55. The reasonable level of test year operating revenue deductions for North Carolina Power (excluding fuel expense) after normalization and pro forma adjustments, under present rates, is \$96,648,000.

56. The proper capitalization ratios for use in this proceeding are as follows:

Long-Term Debt	49.53%
Preferred Stock	9.63%
Common Equity	40.62%
Other Paid-In Capital	.22%
Total	100.00%

57. The proper capital cost rates are 8.84%, 7.53%, and 0% for long-term debt, preferred stock, and other paid-in capital, respectively.

58. The constant growth discounted cash flow (DCF) model is the most appropriate cost of equity method to employ in this case.

59. The common equity investor return requirement to the Company is 12.7%.

60. The proper equity flotation cost adjustment to allow the Company is .02%.

61. The total cost of common equity to the Company is 12.72%.

62. Based upon the foregoing findings with respect to the proper capitalization ratios and the appropriate cost rates for each component of capital reflected in said capitalization, the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 10.27%.

63. North Carolina Power should be authorized to increase its annual level of gross revenues under present rates by $13,916,000 (excluding fuel revenue). After giving effect to the approved increase, the annual revenue requirement for North Carolina Power (excluding fuel revenue) is $136,272,000, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

64. The revenue increase adopted herein should be distributed in order to produce customer class rates of return as close to the following as practical:

	% return index
Residential	0.905
Small General Service	1.105
Large General Service	1.085
Lighting	1.150
Overall	1.000

65. The revenue loss caused by the migration of customers from Schedule 6 to Schedule 6P should remain within the industrial class.

66. The Company should design time-of-use rate schedules to be revenue neutral with corresponding non-time-of-use rate schedules.

67. The Company should recognize New Year's Day, Good Friday, Memorial Day, July 4, Labor Day, Thanksgiving (Thursday and Friday), and Christmas Day as off-peak periods for Schedules 1P and 1T, residential time-of-use rate schedules and for Schedules 5P and 6P, nonresidential time-of-use rate schedules. The changes should be implemented as soon as practical.

68. The Company should study other holidays, such as Martin Luther King, Jr., Day, for their appropriateness for inclusion as off-peak holidays.

69. The Company should continue to classify weekends as off-peak periods for energy charges for Schedule 6P.

70. There should be no mid-day off-peak period on weekdays in the nonsummer months for Schedules 5P, 6 and 6P for purposes of this proceeding.

71. The Company should provide separate details on the residential time-of-use customers' monthly bills showing on-peak and off-peak kWh usage and savings over non-time-of-use rates.

72. The Company should offer a time-of-use comparative billing program to its residential customers, but the program may be limited to 200 volunteers at a time.

73. For residential Schedule 1, multiple level kWh charges during the base period (October through May) should be replaced with a flat kWh charge during the base period.

74. The Company should replace the current Residential Conservation Discount of $0.00251/kWh with a 5.0% reduction on kWh charges for Schedules 1 and 1T and on kW and kWh charges for Schedule 1P.

75. It is appropriate for the Company to reference the publications which contain the efficiency standards used to designate residences as Energy Saver Homes in the residential rate schedules rather than include the standards within the rate schedules; however, the Company must keep the current standards on file with the Commission and must obtain Commission approval prior to making any change to the standards.

76. The Company should include a statement under the Energy Conservation Standards section of Schedules 1, 1P, and 1T, for informational purposes, stating that any heat pump or central air conditioner installed in newly constructed residences on or after January 1, 1992, must have a minimum SEER (Seasonal Energy Efficiency Ratio) of 10.0 to qualify for Energy Saver Home status.

77. The Company should include the following water heater guidelines for participation in Schedule 1W, its separately metered off-peak water heating rate:

(1) Minimum 30-gallon tank size
(2) 240 volts
(3) Quick recovery
(4) Minimum 140° temperature setting
(5) Insulation wrap (optional, but strongly encouraged)

78. The Company should not be required to expand its Rider J, residential water heater load control program, into areas where water heater control is not currently offered.

79. The Company should not be required to expand its Rider A/C, load control of residential central air conditioning units, into areas where water heater control is not currently offered.

80. The Company should add clarifying language to Rider A/C stating that the air conditioning load control program is a cycling program which cycles the appliance on for 18 minutes and off for 12 minutes during each 30-minutes of a control period, and that a control period normally lasts no more than four hours per day except during system capacity shortages.

81. The Company should merge Rider J and Rider A/C into one Residential Load Control Rider.

82. Under Line Extension Plan F, individual customers under Section II.B. of the Plan should be charged only for that portion of the applicable cost of service laterals exceeding 200 feet. Subdivisions under Section II.A. of the Plan should continue to be charged for the applicable cost of service laterals even when they do not exceed 200 feet if the criteria under Section II.A. are not met.

83. The Company should discontinue the policy of assigning the unpaid amount of nonresidential accounts to the person of the same name holding a residential account unless the person agrees to such an assignment in writing.

84. The energy charges in the Company's industrial rates need not be further blocked for size or for load factor in this proceeding.

85. The modified on-peak hours proposed for Schedule 5P in the Company's late filed exhibit should be adopted. However, the demand ratchet feature contained in the distribution demand charge of Schedule 5P should not be allowed.

86. The Company should undertake a study to examine the feasibility of offering a separate rate schedule for traffic lights, and should present such study with its next general rate application.

87. The rate design, rate schedules, miscellaneous charges, and terms and conditions proposed by the Company are appropriate and should be adopted, except as modified herein.

88. The test period for the fuel clause proceeding in this docket is the 12-months ending June 30, 1990.

89. The fuel proceeding test period per book system sales are 55,560,803 mWh.

90. The fuel test period per book system generation is 59,233,302 mWh and is broken down by type as follows:

Coal	23,163,688
IC	260,450
Heavy Oil	1,279,127
Gas	88,579
Nuclear	25,491,351
Hydro	2,939,828
Pumped Storage	(2,303,016)
Photovoltaic	44
Purchase & Interchange	
NUG & Non-fuel	8,960,925
Other	7,213,993
Delivered	(7,861,667)
Total	59,233,302

91. The system normalized nuclear capacity factor for use in this proceeding is 65.6%.

92. The normalized generation is based on the 12-month test period ending June 30, 1990.

93. The adjusted test period sales of 57,632,653 mWh results from additional 544,841 mWh of customer growth, 634,379 mWh of additional customer usage, and an additional 892,630 mWh associated with weather normalization added to fuel test period system sales of 55,560,803 mWh.

94. The adjusted test period system generation for use in this proceeding is 61,426,814 mWh and is broken down by type as follows:

	mWh
Coal	27,828,435
IC	312,920
Heavy Oil	1,536,744
Gas	106,407
Nuclear	19,434,866
Hydro	2,939,828
Pumped Storage	(2,303,016)
Photovoltaic	44
Purchase & Interchange	
NUG & Non-fuel	10,765,477
Other	8,666,776
Delivered	(7,861,667)
Total	61,426,814

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

A. The coal fuel price is $14.90/mWh.
B. The internal combustion turbine (IC) fuel price is $20.01/mWh.
C. The heavy oil fuel price is $33.38/mWh.
D. The gas price is $69.21/mWh.
E. The nuclear fuel price is $4.76/mWh.
F. The fuel price for other purchased and interchanged power is $13.26/mWh.
G. The fuel price for delivered purchased and interchanged power is $1.99/mWh.
H. Hydro, pumped storage, photovoltaic, and non-utility generation and non-fuel generation have a zero fuel price.

96. The adjusted system fuel expense for the July 1, 1989, to June 30, 1990, test period for use in this proceeding is $671,353,000.

97. The proper base fuel factor for this proceeding is 1.165¢/kWh, excluding gross receipts tax.

98. The Company should refund to its customers in a lump-sum payment the amount of excess deferred income taxes collected by the Company through the date the rates set in this proceeding become effective, offset by the remainder of the North Anna Unit 4 amortization. Interest on the net refund should be calculated at a rate of 10% per annum, up to and including the date refunds are made.

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

The evidence supporting these findings of fact is contained in the verified application, the Commission's files and records regarding this proceeding, the Commission Orders scheduling hearings, and the testimony of Company witnesses. These findings of fact are essentially informational and uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact concerning the quality of service is found in the testimony of Company witness Rhodes and the public witnesses who appeared at the hearings in Ahoskie, Elizabeth City, Williamston, Roanoke Rapids, and Raleigh. The Commission notes that the record contains substantial testimony that North Carolina Power is providing adequate service and little testimony suggesting any problems as to the adequacy of Vepco's service. A careful consideration of all the evidence bearing on this matter leads the Commission to conclude that the quality of electric service being provided by North Carolina Power to retail customers in North Carolina is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Bolton, Public Staff witness Turner, and CIGFUR witness Phillips.

Company witness Bolton explained that the cost allocation used by the Company in this proceeding was the Summer/Winter Peak and Average (SWPA) methodology as initially approved by this Commission for future use in Docket

No. E-22, Sub 265, and then subsequently approved in Docket No. E-22, Sub 273. The study is based on a 12-month test period ending December 31, 1989. Public Staff witness Turner recommended the continued use of the SWPA for jurisdictional and fully distributed cost allocation purposes explaining that this methodology has been the predominant method approved for use by the Commission, with the Commission having approved its use for VEPCO as well as all CP&L general rate cases since 1982: Docket Nos. E-2, Sub 444, Sub 461, Sub 481, Sub 526, and Sub 537.

Witness Turner explained that the SWPA cost allocation method recognizes the importance of both summer and winter peaks and that a portion of production plant is related to average demand or energy. This method allocates approximately 40% of production plant based on contribution to summer and winter peaks. The remaining 60% of the plant is allocated by average demand or energy.

The Public Staff recommended the SWPA allocation method in this case for two basic reasons. The first reason is that, under this methodology, both seasonal peaks are considered in determining the availability of generating units and system capacity requirements. The second reason is that, when there is a basic need for new capacity, there are generally three types of units to consider. These are peaking units, intermediate or cycling units, and base load units. The selection of the type of unit is an economic one based on the energy (kWh) requirement or the number of hours a unit must operate each year. If little energy is required, the peaking units are more economical. If a large amount of energy is required, the base load units are more economical. While some of the production plant cost is incurred because of the single or dual system one-hour peak, some plant cost is also incurred because of the energy or hour-use requirement.

CIGFUR witness Phillips testified that the most appropriate cost allocation method for the Company is the Summer/Winter Coincident Peak (CP) allocation method and that the SWPA method recommended in this proceeding by both the Company and the Public Staff was no longer appropriate for cost allocation. He stated that, should the Commission decide to allocate production plant by energy, the average and excess method should be used. He also noted that, in this case, the SWPA method yields the lowest rate of return to the North Carolina retail jurisdiction.

The CP allocation method recommended by witness Phillips allocates all production plant solely on the basis of contribution to two one-hour peaks and averages the result. The Commission has concluded in the past and continues to believe that it is reasonable and appropriate to allocate a portion of production plant by average demand or energy in recognition of the role energy requirements play in the determination of the type of plant to be built for electric loads.

Witness Phillips, in response to questions from the Commission, offered his opinion that a peak allocation method was the allocation method most in tune with Least Cost Planning (LCP). He based this on his belief that the purpose of LCP was to reduce peak loads. The Commission agrees that controlling peak loads is one area of least cost planning; however, it is not the single area. LCP also deals with better utilization of existing resources, use of more efficient energy appliances, use of energy during low cost periods, and determining the lowest cost to supply future electric needs while maintaining an adequate and reliable electric supply.

Company witness Bolton was questioned about the low rate of return for the North Carolina retail jurisdiction which results from the use of the SWPA method and whether or not this is a feature of the cost allocation method that remains constant from one period to the next. Witness Bolton observed that this was not a constant feature of the SWPA method and that, as a matter of fact, in the Company's last rate case, the SWPA method produced the highest rate of return of the four (4) methods. He concluded that rates of return vary from year to year and that no one single method is going to produce the same result year after year. He further concluded that it is not appropriate to choose an allocation method based on the rates of return in one particular case.

In its Order dated December 5, 1983, in Docket No. E-22, Sub 273, the Company's last rate case, the Commission concluded that the cost allocation method utilized for ratemaking purposes should recognize the energy-related portion of production plant. Essentially, the Commission reasoned that not all fixed costs (for production plant) represent the cost of meeting system peak demand, and that a significant portion of fixed costs represents the cost of producing kWh during many hours of the year and of producing such kWh at a lower fuel cost per kWh. The Commission continues to be persuaded in this proceeding that the cost allocation method utilized herein should recognize the energy-related portion of production plant fixed costs.

The Commission has also concluded in the previous rate cases that the cost allocation method utilized for ratemaking purposes should continue to recognize peak responsibility as the basis for allocating the demand-related portion of production plant, and that peak responsibility should include both the summer peak and the winter peak. Essentially, the Commission reasoned that the most significant capacity requirements placed on the system were heating and cooling season loads, and that while both types of loads were similar in their impact on system capacity loads, the customer mix contributing to the heating season load is significantly different from the customer mix contributing to the cooling season load. The Commission continues to be persuaded in this proceeding that the cost allocation method utilized herein should recognize both the summer peak and the winter peak as a basis for allocating the demand-related portion of production plant fixed costs.

The Commission concludes in this proceeding that the SWPA method will best recognize the requirement that demand-related production plant fixed costs be allocated based on peak responsibility. The method also recognizes that not all production plant fixed costs are demand-related, and it recognizes that energy-related production plant fixed cost should be allocated by kWh energy. The Commission concludes that the SWPA method is the most reasonable and appropriate method for determining jurisdictional and customer class cost of service.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 7 AND 8

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Rhodes, Zimmerman and Evans and Public Staff witness Maness.

The Company initially solicited proposals from non-utility generators in 1986. The 1986 solicitation, which was limited to qualifying facilities (QFs) and used the cost of the Company's Chesterfield 7 plant as the price benchmark, was followed by larger, more formalized solicitations in 1988 and 1989.

The 1988 Request for Proposals for Power Purchases (RFP) was an all-source solicitation, including independent power producers (IPPs), QFs and utilities, and price was a bid factor rather than a benchmark. Once the Company had screened the bids, the cost of each bid was compared to a mix composed of the costs of VEPCO's Darbytown peaking units, its Chesterfield 8 intermediate unit and a medium-sized pulverized coal base load unit. The 1989 RFP was similar to the 1988 RFP, except that future VEPCO's units were included as competitors.

Company witnesses Rhodes and Zimmerman indicated that Virginia Power was currently purchasing approximately 900 mW annually of non-utility generation and have current binding contracts for future purchases of approximately 2800 mW annually. Dr. Rhodes and Mr. Zimmerman also testified that the Company had experienced approximately 654 mW of attrition due to terminated contracts or defaults.

Due to the Panda-Rosemary project declaring commercial operations (at a declared capacity of 185 mW for the winter, rather than the initial estimate of 180 mW) subsequent to the testimony in this docket, but prior to the deadline set in the stipulation entered into with regard to the close of hearing, the current level of capacity purchases is increased to approximately 1050 mW using the summer rating and 1085 mW using the new winter rating. Four facilities provide on average 698.5 mW of this currently available capacity. These four facilities are the Ogden Martin Systems' municipal solid waste facility (60 mW of estimated dependable capacity) and the Hopewell Cogeneration, L. P. combined cycle natural gas cogeneration facility (336.6 mW/summer and 395.6 mW/winter), which resulted from the 1986 solicitation, and the Cogentrix of Rocky Mount coal-fired cogeneration facility (105 mW) and the Panda-Rosemary Corporation combined cycle natural gas cogeneration facility (150 mW/summer and 180 mW/winter) which resulted from the 1988 solicitation.

Of the remaining approximately 2633 mW the Company has binding commitments to purchase in the future (2800 mW minus an average of 167.5 mW for Panda), the evidence indicates that 248 mW of this non-utility generation will come on line in 1991 (plus the average 225 mW of estimated dependable capacity (210 mW/summer rating and 240 mW/winter rating) associated with the delayed Richmond Power Enterprises cogeneration project, assuming RPE does not reach its default date of June 1, 1991, prior to declaring commercial operations).

The Company also agreed on cross-examination that 1058 mW is scheduled to be on-line by the end of 1992, 600 mW of which will be purchased from Doswell, L. P., an IPP which is expected to declare commercial operations in March of 1992.

The Company has requested that it be allowed to recover post-1990 non-utility generation expense outside the framework of a general rate case through purchased capacity and purchased energy riders (generally referred to as NUG riders), both with deferred accounting and true-ups. The Company has proposed an alternative that does not include a true-up. Under the Company's proposal, the Company would file NUG riders annually, concurrently with the Company's filing for fuel charge adjustments pursuant to G.S. 62-133.2, to adjust the levels of NUG expense to recover amounts above the level allowed in base rates. This level would then be adjusted annually until the next general rate case proceeding.

The Public Staff and other intervenors, through cross-examination of Company witnesses, demonstrated considerable opposition to such a mechanism on both policy and legal grounds.

The issues raised by the Company's request for NUG capacity and energy riders are (1) whether there is sufficient justification to treat one ratemaking element (the expense incurred by the Company when making capacity and energy payments to non-utility generators) differently from other expense items in the ratemaking process and (2) does the Commission have the legal authority to approve the NUG rider mechanism proposed by the Company.

The Commission concludes that an annual adjustment of this type outside a general rate case is not authorized under current North Carolina law. Our fuel charge adjustment statute has been narrowly construed. The annual fuel charge adjustment proceedings held by the Commission are specifically provided for in G.S. 62-133.2. Prior to the amendment of G.S. 62-133.2 to specifically allow for a true-up, the North Carolina Court of Appeals in State ex rel. Utilities Commission v. Thornburg, 84 N.C.App. 482, 353 S.E2d 413 (1987), cert. denied, 320 N.C. 517, 358 S.E.2d 533 (1987), held that the Commission's use of an experience modification factor to allow Carolina Power & Light Company to recover a past underrecovery of fuel costs was in excess of the Commission's statutory jurisdiction. Given this holding, the Commission concludes that an adjustment to base rates outside a general rate case, for which there is no specific statutory authority, to reflect a true-up of NUG expenses would be found unauthorized.

The Commission's occasional past use of "true-ups," such as the Curtailment Tracking Rate (CTR) approved by this Commission in 1975 for North Carolina Natural Gas Corporation and the Volume Variation Adjustment Factor (VVAF) approved in 1976 for Public Service Company of North Carolina, was premised on very specific circumstances totally dissimilar to the facts of this case. The CTR and VVAF were approved because of the curtailment of natural gas supply by the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission, because of shortages of regulated natural gas. The specific level of curtailment for each natural gas utility depended upon which curtailment plan the FPC approved, which was then subject to change by the FPC. Because of this dilemma, the Commission approved a provisional rate premised on projected gas availability, which was then corrected for actual gas availability. In the case cited above, the Court of Appeals recognized that, unless specifically provided by statute, the use of true-ups should be "limited to the provisional rate cases in which they have previously been allowed." 84 N.C. App. at 490. The present circumstances are clearly distinguishable from those that led to the CTR and VVAF true-ups. Unlike the natural gas utilities, which had absolutely no control over the volumes (or the cost) of natural gas they would receive at the time the "true-ups" were approved and therefore no control over the revenues or expenses resulting from the volumes received, VEPCO has substantial control through the terms of its bidding program and the negotiations of contracts with the winning bidders over how much electricity is available to be purchased, the terms under which it is available, when it is purchased and at what price.

After considering the entire record in this regard, the Commission concludes that there is insufficient justification to treat non-utility generation expense any different from other expense items in the ratemaking process. The Company's proposed NUG rider mechanism would preclude appropriate regulatory oversight of the Company's overall expenses. This is because increases in payments to NUGs for additional capacity and energy could be offset by decreases in other cost of service items, such as reduced operation and maintenance expenses, and increases in sales and revenues (particularly since use of non-utility generation will likely result in some decreased use of Company-owned generation and therefore decreased expenses, and will likely result in increased revenue from additional sales for which the Company otherwise has negligible expenses). Review of the Company's total cost of service in the context of a general rate case is the most effective way to balance these elements.

In addition, it must be remembered that the Company has the option of recovering some of the NUG expense by providing the Commission with the actual fuel costs incurred by the non-utility generators. Such actual costs may be recovered through the fuel charge adjustment proceedings as the fuel component of purchased power. See G.S. 62-133.2. Control of the bidding process certainly gives the Company the opportunity to require the bid winners to provide this information.

In conclusion, based on the foregoing policy and legal concerns, the Commission rejects the Company's proposal to recover future non-utility generation expenses through purchased capacity and energy riders.

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

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Bolton and Public Staff witness McLawhorn. Witness McLawhorn testified that the Company in its depreciation study filed in this case used the most recent retirement dates for its steam plants in calculating the proposed depreciation rates, but used older retirement dates in the calculation of its theoretical depreciation reserve. He further testified that it is appropriate to use consistent, up-to-date retirement dates for calculating both the depreciation rates and theoretical reserves. Application of consistent retirement dates results in a North Carolina jurisdictional depreciation expense reduction of $238,194. Witness Bolton accepted the adjustment proposed by witness McLawhorn.

The Commission agrees that the Company should consistently use the most current retirement dates in calculating both depreciation rates and theoretical reserves and accepts the steam account adjustment proposed by witness McLawhorn in this case as reasonable.

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

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Bolton and Public Staff witness McLawhorn. Witness McLawhorn testified that the Bath County Pumped Storage Facility had an in-service date of December 1985, yet the Company used an in-service date of July 1986, in calculating the Bath County depreciation rate. He further testified that use of the December 1985, in-service date would reduce the Bath County depreciation rate from 2.02% to 2.00%, and would result in a North Carolina jurisdictional depreciation expense reduction of $8,248. Witness Bolton accepted witness McLawhorn's adjustment.

The Commission agrees with witness McLawhorn regarding the Bath County in-service date and concludes that 2.00% is the reasonable and appropriate depreciation rate to use, and further agrees his expense adjustment is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witness Bolton and Public Staff witness Fernald. The amount of materials and supplies proposed by both the Public Staff and the Company is $11,510,000.

Based on the foregoing, the Commission concludes that the proper level of materials and supplies for use in this proceeding is $11,510,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14-19

The evidence supporting these findings of fact is included in the testimony and exhibits of Company witness Bolton and Public Staff witnesses Fernald and Maness. The amount of total working capital investment proposed by these witnesses is set forth in the following table:

(000's Omitted)

Item	Company	Public Staff	Difference
Deferred fuel less federal income tax	$ 243	$ 0	$ (243)
Prepayments	1,179	453	(726)
Investor funds advanced for operations	4,186	4,186	-
Other additions	1,790	1,790	-
Other deductions	(2,050)	(3,393)	(1,343)
Westinghouse settlement credit	(422)	(422)	-
Surry outage costs	306	0	(306)
Sales and use tax assessment	126	0	(126)
Surry and North Anna generators	779	779	-
Total working capital investment	$ 6,137	$ 3,393	$(2,744)

The first difference in the amount of $243,000 relates to deferred fuel (net of federal income taxes). The Company has proposed to include in rate base as an element of working capital the average balance of underrecovered fuel expense (net of federal income tax) over the period since October 1, 1984. The underrecoveries were of course trued-up pursuant to G.S. 62-133.2, but the Company was allowed no interest as part of the true-ups, and this is what prompts the Company's proposal.

Public Staff witness Fernald testified that inclusion of the deferred fuel underrecovery in rate base would run counter to the actions of the Commission in Docket No. E-100, Sub 55. In that docket, the Commission made no provision to allow utilities to collect interest on underrecoveries, although it had an opportunity to do so. CUCA, in its comments filed in Docket No. E-100, Sub 55, proposed that interest be paid on both fuel overrecoveries and underrecoveries, but the Commission did not adopt this proposal. Ms. Fernald concluded, therefore, that the Commission does not intend for utilities to recover interest or a return on fuel underrecoveries.

Ms. Fernald testified that if the Commission decided to review this matter again, it would be more appropriately handled in the fuel case proceeding due to the difficulty of determining the reasonable amount to include in rate base. Also, Ms. Fernald stated that inclusion of this item in rate base would allow the Company to receive the allowed rate of return on the underrecovery rather than the interest percentage that is paid to customers on overrecoveries.

Company witness Bolton testified that a "one-way street," in which the Company must pay interest on overrecoveries but may not collect interest on underrecoveries, is inequitable to the Company and should not be allowed. Mr. Bolton testified that such underrecoveries are incurred in the course of providing electric service and require the investment of funds by investors. Mr. Bolton stated that, alternatively, the Commission could allow the Company to recover its carrying cost on underrecoveries through the fuel component of rates.

The Commission has analyzed the testimony on this issue. The Commission has already reviewed this matter in Docket No. E-100, Sub 55, in which the Commission amended Rule R8-55, and Docket No. E-100, Sub 47, in which the Commission first adopted Rule R8-55. In the Sub 55 proceeding, the Commission concluded that the payment of interest on refunds of overrecoveries is mandated by G.S. 62-130(e). The Commission did not provide that interest be collected from customers on underrecoveries. In the Sub 47 proceeding, the Commission noted that the time lag in collecting for an underrecovery "should provide the utility with considerable incentive to minimize its fuel costs." Allowing a return on the underrecovery would negate this incentive. Further, the Commission agrees with the Public Staff that inclusion of this item in rate base will allow the Company a higher interest rate on underrecoveries than that paid to customers on overrecoveries. Rate base treatment also allows the Company a return year after year regardless of whether the Company actually underrecovers on fuel in a particular year. For all of these reasons, the Commission concludes that the deferred fuel underrecovery of $243,000 should not be included in rate base.

The second difference in the amount of $726,000 relates to the unamortized balance of the prepaid pension settlement.

In 1988, the Company settled a portion of its pension obligation by purchasing nonparticipating annuity contracts from Equitable Life Assurance Society. The Company then accelerated the recognition of pension gains in 1988 for financial purposes in accordance with Statement of Financial Accounting Standards (SFAS) No. 88 <u>Employers' Accounting for Settlements and Curtailments of Deferred Pension Plans and For Termination Benefits.</u> Gains are normally recognized on a systematic basis as part of the net periodic pension cost. As a result of the acceleration, pension costs will be higher in the future. The Public Staff contends that the gain should be amortized to offset the higher pension costs due to the accelerated recognition of pension gains in 1988 from the Equitable settlement. The Public Staff proposes to amortize the pension settlement gain over the life that the prepaid pension settlement is being amortized and that the unamortized balances of the prepaid settlement and the gain would net to zero.

The Company has recommended that the accelerated recognition of the pension gain be assumed to have occurred in 1988 for ratemaking purposes, and that a related prepaid pension settlement of $726,000 be included in working capital.

The Company contends that its treatment of the Equitable gain is proper for the following reasons:

(1) North Carolina retail ratepayers received the entire benefit of the gain in 1988 since it delayed the Company from filing a rate case.

(2) Since the Company realized less cash inflow than it would have experienced had a rate increase been filed and granted by the Commission, the prepaid pension settlement balance represents an indirect investment of funds by the Company.

(3) The Company's accounting for the gain in the year of settlement was in accordance with SFAS No. 88.

(4) The Company's treatment of the Equitable gain was consistent with the Public Staff's inclusion of an insurance refund as a reduction to group life and disability insurance expense.

After a careful review of the testimony, the Commission disagrees with the Company's position. The Commission can not reasonably presume that ratepayers received the benefit of the settlement gain in 1988 simply because the Company made two unilateral decisions to (1) flow through the gain in 1988 for financial accounting purposes and (2) not to file for a rate increase. No evidence was presented to show that the Company could have justified a rate increase if the gain had not been recorded in 1988. If the Commission adopted the Company's rationale for not filing a rate case, it would be tantamount to allowing the Company rather than the Commission to determine the proper ratemaking treatment of the settlement gain. The proper ratemaking treatment of an item is always subject to review in a general rate case regardless of how a company has accounted for it on its books.

Furthermore, the Commission is not persuaded that the Company's argument that the Company's treatment of the Equitable gain was consistent with the Public Staff's inclusion of an insurance refund as a reduction to fringe benefits. On cross-examination, Mr. Bolton agreed that the insurance refund was not non-recurring Also, the Company has agreed with the Public Staff's inclusion of the insurance refund. Furthermore, Mr. Bolton agreed that the Public Staff had not incorporated the most current reduction in pension expense. Based on the evidence presented, the Commission concludes that the Public Staff's fringe benefit expense is reasonable for use in this proceeding.

Therefore, the Commission finds it proper to decrease pension expense by $30,000 and to remove from rate base the prepaid pension amount of $726,000.

The third difference in the amount of $1,343,000 relates to accounts payable applicable to construction and nuclear fuel. Public Staff witness Fernald testified that the Company did not deduct accounts payable related to construction and nuclear fuel in calculating Allowance for Funds Used During Construction (AFUDC). Ms. Fernald stated that these accounts payable represent funds supplied by creditors rather than investors. Therefore, she deducted the accounts payable from rate base in order to relieve the ratepayers from the unfair burden of paying a return on capital provided by creditors at no cost to the investors.

Company witness Bolton agreed that accounts payable related to construction and nuclear fuel should be deducted in calculating AFUDC. He stated, however, that the Company will revise the AFUDC calculation in January of 1991, and, therefore, Ms. Fernald's adjustment is not necessary. However, Mr. Bolton agreed that the Commission will have to wait until the next rate case to evaluate the system the Company will implement for treating the accounts payable related to construction and nuclear fuel in the AFUDC calculation.

The Commission has carefully analyzed the testimony on this issue. Both the Public Staff and the Company agree that accounts payable related to construction and nuclear fuel should be deducted in calculating AFUDC. The ratepayers should not be required to pay a return to investors on capital that has been supplied by creditors. However, the Company has not been following that procedure. Although the Company states that it will revise the AFUDC calculation in January of 1991, the Commission will not be able to review this calculation for accuracy until the next rate case. Therefore, the Commission concludes that accounts payable applicable to construction and nuclear fuel should be deducted from rate base in determining the proper allowance for working capital for use in this proceeding. This conclusion is consistent with the Commission's treatment of accounts payable related to construction materials and supplies in several Duke Power general rate cases (Docket No. E-7, Subs 289, 314, 338, 391, and 408).

The next difference between the Company and Public Staff cash working capital recommendations in the amount of $306,000 relates to the extraordinary costs of the Surry outage. The Company and the Public Staff have both proposed an adjustment, which has been accepted by the Commission, in the discussion of Findings of Fact Nos. 38-55, to amortize over a three-year period the extraordinary costs related to the lengthy outage at the Surry plant experienced during 1988 and 1989.

The disagreement on this matter in the area of working capital relates to the "unamortized" Surry outage costs. Company witness Bolton testified in rebuttal that the "average unrecovered balance" of the unamortized Surry outage costs during the coming rate year should be included in rate base, in order to compensate the Company for the carrying costs incurred due to the lag between the incurrence of the Surry outage costs and their recovery in rates.

The essence of the disagreement between the Company and the Public Staff relates to whether the adjustment to amortize the Surry outage costs over a three-year period is a normalization of test year expenses or a setting aside of a specific cost for specific recovery. Public Staff witness Maness clearly testified that the intent of the Public Staff's adjustment was to normalize expenses. In his prefiled testimony, he stated that "...the high level of costs incurred to successfully return the units to service should not be charged to the ratepayers on an annual basis." He also testified as follows as to the purpose of his adjustment:

> Q. WHY ARE YOU RECOMMENDING THAT CERTAIN COSTS RELATED TO THE SURRY OUTAGE BE AMORTIZED OVER MORE THAN ONE YEAR?
>
> A. The objective of the ratemaking process is to set rates at a level which will give the Company an opportunity to recover its costs in the future. In order to achieve this objective, the test year expenses upon which rates are set should be adjusted to a normalized level. If rates are set based on a level of expenses in excess of the normal level, the Company will have been given the opportunity to recover amounts in excess of its costs in the future.

Additionally, in determining over what period to amortize Surry outage costs, Mr. Maness testified, "I am proposing that non-fuel nuclear operations and maintenance expenses be normalized by amortizing this amount [the total amount of extraordinary Surry outage costs] over a three-year period."

The Company clearly takes the position that the Surry outage cost amortization should be viewed as a method of recovering a specific cost. In his rebuttal testimony, Mr. Bolton stated as follows:

> To the extent that...an expenditure has been made and there is a significant time lag between the expenditure and the associated rate recovery, and to the extent that there is no provision for this time lag elsewhere in the cost of service, the Company should be made whole for the associated carrying costs. This is the very situation faced by the Company with regard to the Surry outage costs. The Company prudently incurred the costs for the purpose of providing electric service, there will be a significant time lag from the incurrence of the costs to the recovery through rates, and there is no provision elsewhere in the cost of service for the associated carrying costs.

During cross-examination, Mr. Bolton reiterated this point, stating:

> ...we have adopted the Staff's position which is to levelize the recovery of the costs to the Surry outage and until these costs are fully recovered, we would propose including those unrecovered costs in rate base. (Emphasis added).

Mr. Maness testified during his cross-examination that the recovery or non-recovery of the outage costs in 1989 is not the issue:

> ...whether the Company actually recovered the cost in 1989 is not what we're looking at here. We're looking at setting the rates to go forward into the future and to set maintenance expense at a reasonable level.

and;

> ...we're setting rates here on a prospective basis and to the extent that the Company did or did not recover that cost in the past I do not feel is particularly relevant to the rates that we're setting to recover maintenance expense in the future.

The Company also contended that its argument was supported by the inclusion by Mr. Maness of 1988 outage costs in the total to be amortized. However, Mr. Maness testified that he chose to include that amount simply to utilize the total extraordinary cost related to the outage. He stated that it would have also been reasonable to use a lower number and a shorter allocation period to reach a normalized level.

The Commission, as heretofore mentioned, has adopted the adjustment to amortize the extraordinary Surry outage costs. In so doing, the Commission's objective is to normalize expenses, not set aside specific costs incurred in the past for future recovery. The Surry outage costs were incurred in 1988 and 1989; the rates set in this proceeding will be effective in 1991 and future years, unless changed. The test year of 1989 is being used in this proceeding as a model to set rates to be charged on a prospective basis. The Commission is not setting rates today to recover specific costs incurred in 1988 or 1989, even if those costs were abnormally high. The Commission is using 1989 costs as a basis on which to determine rates to be charged in 1991 and future years. In so doing, the costs incurred in 1989 must be adjusted to reflect a normalized level. That normalization is the objective of the Commission's adjustment to Surry expenses.

In determining the amount of working capital to be included in rate base, the Commission must consider whether the inclusion of specific items is or is not representative of the ongoing level of working capital investment. Since the Commission has not allowed the specific recovery of Surry outage costs, there in fact is no "unrecovered" amount to be included in rate base. The Commission must consider instead whether or not the inclusion of $306,000 of working capital related to Surry outage costs in rate base is representative of the ongoing level of working capital investment. The Commission concludes that it is not representative. Mr. Maness' testimony indicates that he has included an amount of costs in Surry nuclear expenses greater than the Company projects to be incurred in the near future. This testimony was not disputed by the Company. Therefore, it would be unreasonable to assume that the Company will underrecover its Surry nuclear expenses in the future. Thus, the Commission concludes that the inclusion of an amount representing unrecovered Surry nuclear expenses in working capital is not representative of the ongoing level of working capital and should not be adopted.

The final area of disagreement as to the level of working capital investment in the amount of $126,000 relates to the Company's inclusion of the unamortized balance of the sales and use tax assessment. As discussed in the Evidence and Conclusions for Findings of Fact Nos. 38-55, the Commission has rejected the Company's proposed amortization of the sales and use tax assessment. Therefore, inclusion of an unamortized balance in working capital is inappropriate. However, it should be noted that had the Commission adopted some form of "amortization" of the sales and use tax assessment, the objective would have been to normalize sales and use tax expense, and inclusion of any balance in working capital would have been subject to the same test of "representativeness" as was applied above to the Surry outage costs.

Based on the foregoing, the Commission concludes that the proper level of cash working capital investment for use in this proceeding is $3,393,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-22

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Bolton and Public Staff witnesses Maness and Fernald. The amounts which the Company and Public Staff presented as their final recommendations as to the Company's original cost rate base are shown in the schedule below:

(000's Omitted)

Item	Company	Public Staff	Difference
Electric plant in service including nuclear fuel	$504,804	$504,804	$ -
Accumulated depreciation	(131,222)	(131,451)	(229)
Accumulated amortization of nuclear fuel	(25,084)	(25,084)	-
Net electric plant in service	348,498	348,269	(229)
Materials and supplies	11,510	11,510	-
Cash working capital	6,137	3,393	(2,744)
Accumulated deferred income taxes	(32,488)	(32,488)	-
Other cost-free capital	(210)	(210)	-
Total original cost rate base	$333,447	$330,474	$ (2,973)

As can be seen from the above schedule, the Company and the Public Staff agree as to the levels of electric plant in service, accumulated nuclear fuel amortization, accumulated deferred income taxes, and other cost-free capital. The Commission therefore concludes that the following amounts are appropriate and reasonable for use in this proceeding:

(000's Omitted)

Item	Amount
Electric plant in service including nuclear fuel	$504,804
Accumulated amortization of nuclear fuel	(25,084)
Accumulated deferred income taxes	(32,488)
Other cost-free capital	(210)

In its Evidence and Conclusions for Finding of Fact No. 13, the Commission concluded that the appropriate level of materials and supplies for use in this proceeding is $11,510,000.

In its Evidence and Conclusions for Findings of Fact Nos. 14-19, the Commission concluded that the appropriate level of cash working capital for use in this proceeding is $3,393,000.

The remaining area of difference between the Company and the Public Staff is the level of accumulated depreciation. This difference results from differing approaches to the adjustment to accumulated depreciation made in correlation to the annualization adjustment to depreciation expense. Public Staff witness Maness testified that he adjusted accumulated depreciation to recognize the impact of the Company's adjustment to annualize depreciation expense to an end-of-period level. He stated that he adjusted the accumulated depreciation balance to reflect the level that would have existed had end-of-period plant been in service for the entire test year, consistent with the adjustment to depreciation expense, which sets rates to recover that expense as if it had been incurred for the entire test year. Mr. Maness also testified that his recommended adjustment was in accordance with long-standing Commission policy and procedure.

Company witness Bolton testified in rebuttal that the Public Staff's recommended adjustment was improper because it denies the Company the opportunity to ever earn a return on a portion of its investment in plant in service. He testified that the Public Staff's adjustment treats the annualized depreciation expense adjustment as if it were an amount of investment recovered as of the end of the test year. Mr. Bolton recommended that the appropriate adjustment to accumulated depreciation be set at no more than one-half of the depreciation expense annualization adjustment. In his view, this would more accurately reflect the average level of investment recovery during the first year in which the new rates will be in effect.

In support of his position, Mr. Bolton set forth an example in which he assumed that the depreciation expense annualization adjustment was $120, and represented investment that would be recovered ratably (at $10 per month) over the first year the rates would be in effect (the "rate year"). In his example, since the entire $120 would not be recovered until the end of the rate year, he maintained that the adjustment to accumulated depreciation should be limited to $60. In his view, this "average level of additional investment recovery" should be the basis for the adjustment to accumulated depreciation.

During cross-examination of Mr. Bolton on the subject of his rebuttal testimony, the Public Staff presented an exhibit which expanded upon the Company's example. The Public Staff's exhibit assumed test year plant additions of $2,400 added to investment ratably throughout the year and a depreciation rate of 10%, resulting in an end-of-test-year net plant balance of $2,280 [$2,400 - ($2,400 x 10%/2)]. The accumulated depreciation adjustment recommended by the Public Staff would reduce the net plant balance for purposes of setting rates by an additional $120, to $2,160 ($2,280 - $120). At a 10% rate of return, this procedure would result in an annual return requirement of $216. Over the rate year, the actual net plant balance would decrease by $240 due to depreciation, from $2,280 to $2,040. The average net plant balance during the rate year would be $2,160 [($2,280 + $2,040) /2]. Therefore, the granted return requirement of $216 would provide the required rate of return of 10% on the average net plant balance during the rate year.

The major difference between the Public Staff's and the Company's examples is that the Company's example assumes that only $10 per month of plant investment would be recovered during the rate year, while the Public Staff's example shows that $20 per month would be recovered. This $20 consists of the $10 included in the depreciation expense annualization adjustment and the $10 embedded in the per books amount of depreciation expense which would also be included in the cost of service. In considering only the depreciation adjustment of $120, Mr. Bolton stated that "the average level of investment recovery during the rate year would be roughly $60, or half of the depreciation expense annualization adjustment...." In fact, as the Public Staff's example shows, when one considers the per books and adjustment components together, the total level of investment recovery during the rate year would be $240, and the average level would be $120, an amount equal to the depreciation expense annualization adjustment.

Based upon the evidence presented in this proceeding, the Commission concludes that the adjustment proposed by the Public Staff is reasonable and appropriate. As testified to by Public Staff witness Maness, this adjustment has been consistently made by the Commission for many years in accordance with long-standing ratemaking policies. The Commission especially takes judicial notice of its Final Order in the case of Duke Power Company, Docket No. E-7, Sub 289, Order issued October 7, 1980, a case that was ultimately appealed to the North Carolina Supreme Court. In that case, the Commission's Order stated as follows:

> In a recent Duke general rate case, Docket No. E-7, Sub 237, the Commission concluded that:
>
> > 'In arriving at a proper level of operating revenue deductions which is consistent with the test year level of investment the Commission has added an amount to depreciation expense to annualize depreciation applicable thereto. It is, therefore, entirely consistent and proper to make the corollary adjustment to accumulated depreciation. The Commission acknowledges that the pro forma adjustment to depreciation expense has not been collected from the company's customers during the test year. However, when considering the test year, the company has, in fact, not actually incurred such cost. Further, the

> Commission believes that the corollary adjustment to accumulated expense is necessary to achieve a proper and equitable matching of revenues and costs.'
>
> The Commission does not believe that the evidence in this case warrants a change in the Commission's position with respect to this matter. The Commission, therefore, concludes that the adjustment of $2,076,000 proposed by the Public Staff to increase accumulated depreciation to give full effect to the pro forma adjustment to annualize depreciation expense is proper.

Order pp. 14-15.

The Commission also takes judicial notice of the opinion of the Supreme Court in State ex rel. Utilities Commission v. Duke Power Co., 305 N.C. 1 (1982), in which the Court stated as follows:

> If, as here were (sic) facilities come into service at various times during the test year, Duke is allowed to make the *pro forma* adjustment to the test year depreciation expense to reflect the future depreciation revenue requirement of a full year's depreciation and is not required to increase its accumulated depreciation account by the same amount (emphasis added) to reflect what it would have been had the facilities been in the rate base for the full year, its customers would pay not only the adjustment for increased depreciation but would also pay a rate of return on an inflated rate base.

Id. at 17-18

and

> When the Commission allowed Duke to annualize its actual test year depreciation expenses (*i.e.* increase them to reflect what they would have been had all of its property used and useful at the end of the test year been in service for the entire test period), it correctly applied a corresponding or offsetting adjustment to increase the accumulated depreciation account to reflect what it would have been had that property been in service for the entire test year.

Id. at 19.

Established case law and Commission precedent thus strongly support the adoption of the Public Staff's position in this proceeding. The Commission finds no grounds in the evidence presented for changing its long-established policy.

The Commission also notes that this issue has been addressed in at least one prior rate case of Virginia Electric and Power Company, as well. In that case (Docket No. E-22, Sub 257, Order issued October 27, 1981), the Commission concluded that the Public Staff adjustment to accumulated depreciation to reflect the annualization of depreciation expense was appropriate. The Commission stated as follows:

> The Commission concludes that witness Carter's adjustment to witness Johnson's level of accumulated provision to bring it to an end-of-period balance at June 30, 1980, is appropriate. Since witness Johnson updated plant in service to June 30, 1980, and depreciation expense has been stated based on the plant in service at June 30, 1980, the starting point for determining the appropriate level of depreciation reserve should be the actual balance at June 30, 1980, and this balance should be increased by the difference between the annual level of depreciation expense based on plant in service at June 30, 1980, and the actual depreciation expense for the 12 months ended June 30, 1980.

Order p. 10.

The Commission rejects the Company's contention that the Public Staff's recommended adjustment denies the Company an opportunity to ever earn a return on a portion of its investment in plant in service. After careful examination of the examples presented by the Company and the Public Staff, the Commission finds that the example set forth by the Public Staff best demonstrates the effect of the annualization adjustment upon operations in the rate year. The Company's example only looks at one aspect of rate year operations, the recovery of investment represented by the depreciation expense annualization adjustment. The Company's example fails to take into account the recovery of investment represented by per books depreciation expense. The Public Staff's example demonstrates, by considering investment recovery from both sources, that the average level of recovered investment in the rate year will be appropriately tracked by adoption of the Public Staff's recommended adjustment. It should also be noted that the Public Staff's recommended adjustment is already inherently conservative since it does not take into account any recovery during the rate year of plant which was placed into service prior to the test year, plant which will continue to be depreciated during the rate year.

During cross-examination on the Public Staff example, Mr. Bolton maintained that the Public Staff's recommended adjustment would cause the Company to suffer a time-value-of-money loss because the Company would recover a return on average investment over a twelve-month period, rather than a return on its beginning investment on the first day of the new rates. The Commission rejects Mr. Bolton's argument as being unpersuasive. The Public Staff's example shows that the appropriate annual return requirement is produced by utilization of the Public Staff adjustment. The Commission believes that a provision of a full annual return adequately compensates the Company.

In summary, the Commission continues to believe that when an adjustment to increase depreciation expense is made for the purpose of annualizing depreciation on end-of-period plant, a corollary adjustment in the same amount should be made to accumulated depreciation. Such an adjustment is appropriate because it maintains consistency in the treatment of expenses and rate base. Since the result of the depreciation expense annualization adjustment is to state depreciation expense as if end-of-period plant had been in service for the entire preceding twelve months, it is consistent and appropriate to also adjust accumulated depreciation as if the plant had been in service for that period of time.

The Commission therefore concludes that the Public Staff adjustment to credit accumulated depreciation by $229,000 is appropriate. The Commission has concluded in Evidence and Conclusions for Findings of Fact Nos. 38-55 that the Company's proposed adjustment in the amount of $71,000 relating to the acceleration of the depreciation of the North Anna Unit 1 steam generators is appropriate. As discussed above, the Commission further concludes that a corollary adjustment to accumulated depreciation in the amount of $71,000 is also appropriate. Accordingly, the Commission concludes that the appropriate level of accumulated depreciation for use in this proceeding is $(131,522,000).

The Commission concludes that the Company's reasonable original cost rate base used and useful in providing service to its North Carolina retail customers for purposes of this proceeding is $330,403,000, made up of the following components:

(000's Omitted)

Item	Amount
Electric plant in service including nuclear fuel	$504,804
Accumulated depreciation	(131,522)
Accumulated amortization of nuclear fuel	(25,084)
Net electric plant in service	348,198
Materials and supplies	11,510
Cash working capital	3,393
Accumulated deferred income taxes	(32,488)
Other cost-free capital	(210)
Total original cost rate base	$330,403

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 23-29

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and was not opposed by any party.

The testimony and exhibits of witness Evans show the level of sales and revenues for the test period ending December 31, 1989, through the update period ending September 30, 1990, as follows:

		Megawatthours
A.	N.C. jurisdictional sales	2,352,284
B.	Unbilled sales	26,592

		Basic Revenues
A.	Basic rate schedules	$114,859,301
B.	Unbilled revenues	1,353,048
C.	Load management credits	(132,151)
D.	Facilities Charges	362,344
E.	Miscellaneous Service Charges	717,562

There is no other evidence in the record contesting the level of sales and revenues discussed above. The Commission concludes that they are reasonable for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30-33

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Turner.

Witness Evans filed testimony and exhibits adjusting per book sales and revenues related to weather normalization, customer growth, and increased usage for the test period ending December 31, 1989, through the update period ending September 30, 1990. His adjustment is $4,925,945 based on an adjustment of 99,480 mWh of additional sales.

Witness Turner filed testimony and exhibits adjusting per book sales and revenues for weather normalization, customer growth, and increased usage for the test period ending December 31, 1989, through the update period ending September 30, 1990. The adjustment presented by witness Turner for the North Carolina retail jurisdiction is $4,738,524 based on an adjustment of 95,918 mWh.

He further testified that customer growth is calculated by multiplying the monthly change in customers by average kWh per bill and summing the result over the 12-month test period, where the change in customers is the difference between the end-of-period customer level and actual customers. Increased usage is the difference between test year average and the average usage of the preceding year multiplied by one-half the end-of-period level customers. The revenue associated with growth, usage, and weather are multiplied by average rates based on annualized revenues and test year kWh sales.

The end-of-period customer level for each rate schedule, as determined by witness Turner, is computed using an equation based on a trended analysis or regression of actual billings for the 36-month period ending August 1990 where in all but one case, Traffic Lighting, the equation selected as representative of customer growth was a polynomial in the form: $A_2x^2 + A_1x + A_0$ = customers. Traffic Lighting's representative equation was an exponential in the form: $A_0\epsilon^{A1x}$ = customers. The basis for curve selection was an equation based on the most recent 36 months of actual data and highest value of R-square.

Witness Turner stated that the advantage of trended analysis or regression is that the equation gives weight to the number of bills before, during, and after the end of the test period and enables one to develop a trend line representative of the growth in bills. A simplified alternative has been to use the actual number of bills in the last month of the test period ignoring the monthly variation in bills.

He also stated that the Commission has approved the use of regression analysis to normalize the end-of-period level of customers in the following general rate cases: Docket Nos. E-2, Sub 537 (the most recent electric rate case before this Commission); E-7, Sub 314; E-7, Sub 338; E-7, Sub 358; E-7, Sub 373; E-7, Sub 391; E-7, Sub 408 (Duke Power Company rate cases); and E-22, Sub 265 and E-22, Sub 273 (VEPCO's last two North Carolina rate cases).

Witness Turner presented for filing additional exhibits updating customer growth through August 31, 1990, and September 30, 1990. Customer growth updated through August 31, 1990, was filed by witness Turner on November 21, 1990, as shown by Exhibit BRTU-1, page 1 of 1. On December 19, 1990, witness Turner's late-filed exhibit BRTSU-1, consisting of one page was filed updating customer growth through September 30, 1990.

The Commission concludes that the adjustment for weather normalization, customer growth, and increased usage, as presented by Public Staff witness Turner, and accepted by the Company, is reasonable and appropriate for use in determining the end-of-period level of kWh sales and revenues. The appropriate adjustment to revenues for the period ending December 31, 1989, through the update period ending September 30, 1990, due to weather normalization, customer growth, and increased usage is $4,738,524 based on additional sales of 95,918 mWh.

Based on the foregoing conclusions, for the test period ending December 31, 1989, through the update period ending September 30, 1990, the reasonable and appropriate adjusted level of sales is as follows:

		mWh
A.	N.C. Jurisdictional Sales	2,352,284
B.	Unbilled sales	26,592
C.	Weather normalization	(4,617)
D.	Customer growth	48,528
E.	Increased usage	52,007
	Total	2,474,794

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 34-36

The evidence in the record supporting these findings of fact is contained in the testimony and exhibits of Company witness Evans. These adjustments were not contested by any party, and are reasonable.

The end-of-period level of load management credits of $(132,151) is discussed in the Evidence and Conclusions for Finding of Fact No. 27. Additional credits through the update period ending September 30, 1990, of $(30,690) result in a total adjustment of $(162,841). There being no evidence in the record contesting these adjustments, the Commission concludes that they are reasonable.

Based on the foregoing conclusion and the Commission's previous conclusions, the Commission now concludes that the reasonable and appropriate level of end-of-period revenues, excluding other miscellaneous revenue, for the test period ending December 31, 1989, through the update period ending September 30, 1990, is $121,867,938 as shown below:

	Item	Amount
A.	Basic rate schedule revenues	$114,859,301
B.	Unbilled revenues	1,353,048
C.	Weather normalization, customer growth and increased usage revenues (including growth in load management)	4,738,524
	Subtotal	$120,950,873
D.	Load management credit	(162,841)
E.	Facilities charges	362,344
F.	Miscellaneous service charges	717,562
	Total	$121,867,938

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 37

The evidence supporting this finding of fact is contained in the exhibits and other data and records filed by the Company in this proceeding. In addition to the end-of-period revenue of $121,868,000 found reasonable and appropriate in the Evidence and Conclusions for Findings of Fact Nos. 34 - 36, the Company recorded during the test year $460,000 in other miscellaneous revenue. Additionally, the Company made an adjustment of $28,000 to annualize pole attachment revenue. No party contested the inclusion of either the per books other miscellaneous revenue of $460,000 or the annualization adjustment of $28,000.

The Commission therefore concludes that the proper gross revenue for the Company for the test year (excluding fuel revenue), under present rates and after accounting and pro-forma adjustments, is $122,356,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 38-55

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Bolton and Public Staff witness Maness. The levels of operating revenue deductions (excluding fuel expenses) proposed by the Company and the Public Staff representing their final positions are set forth in the schedule below:

(000's Omitted)

Item	Company	Public Staff	Difference
Operation and maintenance expense	$59,711	$58,502	$(1,209)
Depreciation and amortization	20,293	19,777	(516)
Other taxes	9,869	9,740	(129)
Income taxes	6,879	7,551	672
Charitable contributions	70	0	(70)
Interest on customer deposits	133	133	-
Interest on tax deficiencies	91	91	-
Total operating revenue deductions	$97,046	$95,794	$(1,252)

As can be seen from the above schedule, the Company and the Public Staff agree on the amounts to be included for interest on customer deposits and interest on tax deficiencies. The Commission thus concludes that the levels of interest on customer deposits and interest on tax deficiencies appropriate for use in this proceeding are $133,000 and $91,000, respectively.

One non-quantitative difference between the parties regarding interest on tax deficiencies should be discussed. Public Staff witness Maness based his recommendation of $91,000 for interest on tax deficiencies upon a ten-year average of actual interest payments to the Internal Revenue Service. In his rebuttal testimony, Company witness Bolton maintained that a five-year average would be more appropriate than a ten-year average because it would better reflect the more recent levels of the Company's tax liability. He did not, however, recommend an adjustment, because in this instance the difference between the two methodologies "is not material."

The Commission recognizes that different circumstances may make appropriate the use of different formulae to determine a representative amount of any expense item. The Commission does not conclude by virtue of its adoption of $91,000 in this case that a ten-year average is to be used for all proceedings in the future. In fact, the issue of interest on tax deficiencies is very complex and will require continued evaluation in future proceedings.

Operation & Maintenance Expenses

The first area of quantitative difference between the Company and the Public Staff is operation and maintenance expense. The difference of $(1,209,000) is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Adjustment to other post-retirement benefits accrual	$ (126)
Removal of OPRB accrual	(1,024)
Removal of TMI contribution	(31)
Adjustment to non-utility generation expenses	(17)
Removal of 50% of selected officers' compensation	(14)
Adjustment to fringe benefits	(30)
Adjustment to the Surry outage costs	33
Total	$(1,209)

The first two Public Staff adjustments concern the proper treatment to be given in this proceeding to other post-retirement benefits (OPRB) expenses.

The Company advocates an adjustment that increases test year cost of service to reflect a change from the "pay-as-you-go" method to the "accrual" method of accounting for other post-retirement benefits. These benefits are medical and life insurance benefits provided by the Company to its retired employees and qualified dependents. For accounting and ratemaking purposes, the costs of these employee benefits historically have been recognized in the period when the costs are actually paid.

The Company proposes, consistent with the proposals of the Financial Accounting Standards Board (FASB), that the method of accounting for OPRB be changed to reflect the accrual of these costs over the entire working careers of employees. There are two components of the adjustment to switch to the accrual method. First, the annual level of costs under the accrual method is somewhat higher than under the pay-as-you-go method. Second, there is a transition obligation. This obligation is the unfunded future OPRB costs earned by employees as of the date the accrual method is first adopted.

The theory behind the Company proposal and the proposed FASB standard is to recognize these costs in the proper period so that future customers will not be burdened with costs related to services rendered to prior customers. OPRB represents a form of deferred compensation, and the anticipated expense should be recognized in the period in which the associated employee service is rendered.

Under accrual accounting, collections will be placed in an external fund, and benefits will be paid from this fund. Use of the external fund will permit the Company to take certain current tax deductions that will flow to the benefit of ratepayers.

Public Staff witness Maness recommends that the OPRB adjustment be excluded from cost of service in this proceeding. Mr. Maness argues that the Company's adjustment is inherently tied to the proposed accounting standard, and that the standard has not been released. Mr. Maness contends that until the effective date of the new standard in 1993, when the accrual method will become mandatory, the pay-as-you-go method will still be the generally accepted method of accounting for these costs. Additionally, Mr. Maness asserts that costs upon which the accrual will be based are founded upon estimates of future costs and events, and actual levels may differ from the estimate. Mr. Maness suggests that FASB may delay the effective date of the standard beyond 1993, and the Commission should not allow the Company to "jump the gun" in this case.

On rebuttal, Company witness Bolton refuted Mr. Maness' assertion that the Company's request to change to accrual accounting for OPRB is tied to the proposed accounting standard. The snow-balling growth in medical costs prompted the Company to seek a more appropriate ratemaking treatment of these costs, just as the growth prompted the FASB to address the issue of proper accounting for them.

Mr. Bolton testified that the objectives of the standard are consistent with the objectives of proper ratemaking, and that accrual accounting for OPRB is the appropriate ratemaking treatment even if a FASB standard is never issued. Presently, the Company has an unrecorded OPRB liability and is incurring an unrecorded accrual level of expense.

Mr. Bolton testified that although estimates and uncertainties are involved in OPRB accrual accounting, such estimates are not much different than those made routinely for accounting and ratemaking purposes. Decommissioning, depreciation and pension expenses and unbilled revenue accrual require similar estimates.

As to the delay in the date when the accounting standard will become mandatory, Mr. Bolton testified that accrual accounting for OPRB is more appropriate today for ratemaking purposes than pay-as-you-go, and that the FASB has not delayed the effective date due to any concern that accrual is not proper accounting. The purpose of the delay is to permit affected parties time to prepare for the change. Mr. Bolton assured the Commission that the Company is prepared to make the change now, and there is no basis for delay.

Based upon a thorough review of the evidence, the Commission rules that it is reasonable and wise to approve accrual accounting for OPRB benefits in this case. The Commission takes judicial notice of the fact that the FASB has now released the standard. Continued use of the pay-as-you-go accounting method continues to push onto future ratepayers current costs that are incurred to provide service to today's ratepayers. Mr. Maness conceded on cross-examination that accrual accounting for costs such as these is theoretically sound. The Commission agrees that accrual accounting for OPRB is theoretically sound and notes further that the Commission has approved accrual accounting for many similar costs. For example, the computation of the OPRB expense and liability is similar to the computation of the closely related expense and liability for pensions under SFAS No. 87. The Commission currently approves accrual accounting for ratemaking for pension expense.

The Commission is not persuaded that approval of accrual accounting should be delayed because of the use of estimates in the computation. The entire ratemaking process relies on many categories of estimates. If accrual accounting for ratemaking is delayed until the FASB standard becomes mandatory, it will be necessary to make the same estimates at that future time. Also, it is significant that funds collected thorough rates for OPRB will be placed in an external trust fund, and the earnings on this fund will be used to reduce the future OPRB expense. Therefore, whatever level of funding occurs, it will directly benefit the ratepayers by serving to reduce future OPRB expense.

The primary objection of the Public Staff concerns the timing of the change to accrual accounting, not the wisdom of the change. It is the Commission's opinion that there is nothing to be gained by waiting to approve accrual accounting until the FASB makes the change mandatory. One reason that annual costs will increase under accrual accounting is that the transition or "catch-up obligation" must be funded over 20 years. Delaying the change to accrual accounting will merely increase the amount of the transition obligation, hence, the greater the transition liability. We disagree with Mr. Maness that starting accrual now is "jumping the gun." Instead, a delay until 1993 or beyond places the Company that much further behind in funding the ever increasing unfunded OPRB liability. If pay-as-you-go will no longer be acceptable under generally accepted accounting principles in 1993 when the new standard becomes mandatory, the Commission sees no reason to sanction this accounting method simply because time is necessary for other companies to familiarize themselves with the new requirements.

The other issue regarding the OPRB adjustment concerns the attribution period. Public Staff witness Maness testified that if accrual accounting is adopted, an adjustment should be made to increase the time period to which OPRB costs are attributed. Under the Company proposal the attribution period extends from the date of hire to the date the employee first becomes fully eligible for the benefits. For the Company, this is age 55. Mr. Maness recommends extending this date to age 63, the average age for retirement for Company employees.

Although Mr. Maness acknowledges that the Company's position is consistent with the attribution period called for in the FASB's proposed standard, Mr. Maness contends that it would be more appropriate for ratemaking purposes to spread the OPRB costs over the entire service period of the employee. Mr. Maness testified, "It is my opinion that the OPRB expense should be accrued over a period that extends from the date of hire to the expected retirement date, thus encompassing the full period over which the employee is expected to provide service to the Company."

On rebuttal, Company witness Bolton testified that the Public Staff adjustment to lengthen the attribution period should be rejected. Mr. Bolton stated that use of the longer attribution period will establish a level of OPRB accrual that will fail to provide for an adequate provision for the accrued liability.

The Commission concludes that the attribution period should be measured from the date of hire to the date of full eligibility for the benefits. Employees are eligible for the OPRB benefit at age 55. We agree with Mr. Bolton that accruing the expense based on the expected retirement date will fail fully to accrue the liability as of the date of full eligibility of the benefits.

The Commission further notes that the attribution period advocated by the Company is fully consistent with the FASB accounting standard. After examining several alternatives, the FASB chose an attribution period ending with a date at which full eligibility for the future obligation should be recognized.

The Commission thus concludes that the proposed adjustment by the Public Staff to reverse the Company's OPRB expense adjustment is inappropriate and should be rejected.

The next Public Staff adjustment is the removal of the Three Mile Island (TMI) cleanup contribution of $31,000 from expenses. Mr. Maness testified that he excluded the TMI cleanup costs for the following reasons: 1) it would be unfair to charge North Carolina retail ratepayers for costs of an accident which occurred in another state, 2) the Commission has followed a consistent policy of disallowing this expense for ratemaking, and 3) 1989 was the last year in which a TMI contribution was to be made to the Edison Electric Institute (EEI).

Company witness Bolton testified that North Carolina ratepayers benefitted from the TMI contribution to the extent that the Company's participation in the TMI cleanup efforts helped mitigate damage to the nuclear industry and helped finance nuclear research. Additionally, Mr. Bolton testified that this item is a non-recurring expense which should at least be amortized over three years; however, due to immateriality he proposed a one-year recovery.

After careful review, the Commission concludes that North Carolina retail ratepayers should not be required to pay in rates the costs associated with the TMI cleanup. The Commission concludes that the $(31,000) adjustment proposed by the Public Staff to remove this expense is proper. None of the circumstances surrounding the TMI cleanup contributions have been shown to have changed since the Commission's prior decisions on this issue. Moreover, there is a further reason to remove this expense; namely, 1989 was the final year in which this contribution was to be made. In order to set expenses at a representative level for operations in the future, this expense should be removed.

The next adjustment made by the Public Staff relates to the appropriate amount of non-utility generation expense. Before considering any offsets to NUG expense, the Company and the Public Staff have both recommended that the total amount of NUG expense be set at an annualized level of $12,563,000. However, both the Company and the Public Staff have also proposed certain offsets to NUG expense for purposes of this proceeding. The differences between the parties result from differing assumptions and factors utilized in calculating the offsets. The following table summarizes the differences between the Company and the Public Staff:

(000's Omitted)

Item	Company	Public Staff	Difference
Amount included in growth adjustment	$ (161)	$ (181)	$ (20)
Generation mix adjustment	(247)	(247)	-
Capacity revenue offset	(273)	(270)	3
Total	(681)	$ (698)	$ (17)

The first difference, the amount included in the growth adjustment, relates to the reduction in the end-of-period level of NUG expense necessary to account for the fact that an adjustment to increase NUG expense is also embedded in the customer growth-expenses adjustment. If this offset was not made, the customer growth component of NUG expense would be included in cost-of-service twice. Public Staff witness Maness testified that he made this adjustment in order to prevent overstatement of NUG energy costs.

In the calculation of NUG expense in his rebuttal testimony, exhibits, and workpapers, Company witness Bolton adopted the adjustment made by Mr. Maness in his supplemental filing, a reduction of $(161,000). However, this reduction was based on customer growth through August, 1990. In his Final Exhibit, Mr. Maness updated customer growth through September 1990, thus increasing his adjustment to $(181,000). Since the Commission has adopted the Public Staff's customer growth adjustment, the Commission concludes that a growth adjustment offset to NUG expense of $(181,000) is appropriate.

Both parties agrees that the appropriate generation mix adjustment is $(247,000) and the Commission concludes that such adjustment is appropriate for use in this proceeding.

The final NUG offset difference between the Company and the Public Staff is related to the appropriate capacity offset amount by which to reduce NUG expense. Both parties agree that a capacity offset adjustment is appropriate in order to recognize that to the extent capacity costs incurred after the date at which cost of service is annualized are included in expenses, they should be considered to be at least partially offset by operating revenue. These increases in capacity costs are being incurred to meet increases in the demand for electricity.

There are several differences between the calculations of the capacity offset adjustments performed by the Company and the Public Staff. First, the parties differed regarding the number of megawatthours to which the capacity offset rate should be applied. The Public Staff based its mWh level on a proforma increase in annualized sales through December 31, 1990. This increase was calculated by taking the average growth in the Public Staff's level of adjusted mWh sales between December 1989, and September 1990, and projecting that growth through December 1990. December 1990, is the last month in which a NUG project included in this proceeding commenced commercial operations. Thus, the Public Staff multiplied its capacity offset factor by the difference between annualized mWh sales as of September 1990, and projected annualized mWh sales as of December 1990. The Company calculated its mWh sales in much the same fashion, except that it multiplied the average monthly growth in annualized mWh sales by twelve months rather than three months and utilized its own growth calculation to determine the amounts.

The second difference results from the fact that the Company calculated a capacity offset adjustment for both NUG capacity and energy costs, while the Public Staff restricted its adjustment to NUG capacity costs.

The final difference relates to the methodology used to calculate the capacity offset factors. The Company calculated its capacity and energy offset factors by dividing annualized NUG expense by annualized mWh sales. The Public Staff calculated its capacity offset factor by dividing per books production plant-related capacity costs by per books mWh sales. Company witness Bolton criticized the Public Staff's calculation because it includes all production capacity-related costs instead of only NUG costs. Mr. Bolton stated, "By doing this, he [Public Staff witness Maness] is assuming that all marginal sales over those used to set rates would be supplied from the additional NUG capacity." Mr. Maness testified that he felt that the calculation of the factor using all production plant-related capacity costs was appropriate because his examination of the increases in annualized non-utility generation mWh from August to September, and then on to what the Company had projected for December, was much greater than the customer growth that the Company expected. Additionally, Mr. Maness stated, "When I saw that the major growth in generation for the Company, as compared to growth in sales, is coming from non-utility generation sources, I felt that it would be reasonable to use a relatively high rate per kilowatthour to determine an estimated revenue loss."

In determining the appropriate capacity revenue offset, the Commission must use its judgment to determine a reasonable amount. There is no practical way to precisely determine the incremental revenue recovery related to the incremental NUG expense added to the cost of service after that cost of service has already been annualized to an end-of-period level. The Commission notes that for all the differing assumptions and methods used by the parties, they arrived at total offset amounts which differ by less than 2%. On the whole, however, the Commission finds that the Public Staff calculation is more appropriate for use in this proceeding than that of the Company. There are several reasons for this conclusion. First, the incremental mWh amount to which the Public Staff applies its capacity offset factor, by virtue of being projected through December 1990, correlates with the month in which the final NUG project included in cost of service in this proceeding (the Panda unit) commenced commercial operation. Second, while the Commission believes that there is some merit in the Company's proposal to offset NUG energy costs as well as capacity costs, the Commission finds that the objective of so adjusting energy costs is adequately achieved in this proceeding by the generation mix adjustment. The generation mix adjustment reduces energy costs to an appropriate end-of-period level by removing from cost of service the costs of displaced energy. By so doing, it achieves a similar objective as would the offset of energy costs to reflect increased operating revenue recovery.

Finally, the Commission finds the argument advanced by Mr. Maness regarding the reasonableness of the Public Staff's capacity offset factor to be persuasive. The NUG projects added to cost of service after September (Panda and Cogentrix) represent an annual addition of 37,556 mWh to the Company's operations (on a N.C. retail sales level, using the factors found in Mr. Bolton's rebuttal workpapers).

Correspondingly, the Final Exhibit filed by Mr. Maness in this proceeding shows that the proforma increase in N.C. retail mWh sales projected through December 1990 is 13,413 mWh over and above the September 1990, level. Since the increase in annualized NUG mWh built into this case after September is greater than the increase in annualized mWh sales through the month in which the NUG capacity is added to cost of service, the Commission finds it reasonable to assume for purposes of this proceeding that a substantial portion of the incremental sales after September was supplied by the NUG projects. The Commission therefore concludes that the use of the Public Staff's capacity offset factor is reasonable and appropriate.

Therefore, the Commission concludes that the Public Staff's capacity revenue offset adjustment of $(270,000) is appropriate for use in this proceeding. In summary, the Commission concludes that the total offset adjustments appropriate for use in this proceeding equal $(698,000), and the Public Staff's total adjustment of $(17,000) to the Company-proposed amount is proper.

The next adjustment made by the Public Staff is the removal from expenses of 50% of the compensation paid by the Company to three of its executive officers. Public Staff witness Maness testified that consistent with the adjustments made by the Commission in recent years for other electric utilities, he was recommending an adjustment to charge to the stockholder 50% of the compensation of those officers whose functions are most closely linked with meeting the demands of the Company's sole common stockholder, Dominion Resources, Inc., (DRI). Mr. Maness indicated that the officers whose compensation he split were as follows:

(1) President/Chief Executive Officer

(2) Chairman of the Board of Directors

(3) President/Chief Operating Officer of DRI

Mr. Maness testified that these three individuals were closely linked to meeting the demands of the common shareholder. All three serve on the VEPCO Board of Directors, as well as the DRI Board of Directors. The Chairman of the VEPCO Board is also the Chairman of the DRI Board, as well as of the Boards of DRI's other subsidiaries, Dominion Capital, Dominion Energy, and Dominion Lands. Mr. Maness testified that this adjustment is especially appropriate for VEPCO given the nature of DRI's non-regulated business interests, particularly independent power production. DRI has ownership or investment interests in several non-utility electric power generation projects. Mr. Maness testified that given DRI's aggressive approach to independent power production, it is possible that the interests of DRI as they relate to its non-regulated businesses will not always coincide with the interests of VEPCO's retail ratepayers.

Mr. Maness also testified that the Commission has adopted an adjustment consistent with his approach in each of the five Duke Power and/or CP&L general rate cases decided since November 1984. During that period, the Company has not filed a general rate case.

Company witness Bolton testified that Mr. Maness' adjustment is inappropriate because it ignores the fact that only the portion of the officers' compensation attributable to VEPCO business is charged to VEPCO. For instance, during the test year, only 42% of the compensation of the Chairman of the Board (Mr. Berry) and 27% of the compensation of the President of DRI (Mr. Capps) (both DRI employees) was charged to VEPCO. The remainder of these individuals' compensation was charged to shareholders. Mr. Bolton indicated that the shareholders he referred to in his rebuttal testimony were the shareholders of DRI. However, Mr. Maness testified that he was not quarreling with the allocation process. He agreed that allocations are made between DRI, VEPCO, and other subsidiaries based on the activities that the officers perform for the various companies. However, he stated that the compensation paid by VEPCO to the two DRI officers through the allocation process is definitely executive-level compensation. Therefore, he considers the compensation paid to them by VEPCO to be executive compensation.

Mr. Bolton also testified that the interests of the shareholders and the ratepayers are interrelated, and that the actions of Company officers to protect and preserve the Company's financial health directly benefit the ratepayers. Mr. Bolton went on to say that the interests of the shareholders and the ratepayers are identical. Mr. Maness testified that the stockholder's objective to maximize the profit of the Company may work counter to the interests of the ratepayers in low and reasonable rates. Mr. Maness also testified that he had singled out no specific activity that was closely linked to the demands of the shareholders, but that by the nature of their position within the Company, these officers have a responsibility to both the ratepayers of the Company and the common stockholder.

After careful consideration, the Commission concludes that the Public Staff adjustment to exclude 50% of the compensation of the three officers in question is appropriate. The Commission finds that it is reasonable for the Company's common stockholder to bear 50% of the compensation expense of the Company officers whose function is most closely linked with meeting the demands of the stockholder. The Commission notes that this adjustment is consistent with adjustments made in the following five general rate cases:

Duke Power Company, Docket No. E-7, Subs 391 and 408; CP&L, Docket No. E-2, Subs 481, 526, and 537.

The Commission rejects the Company's contention that the adjustment is inappropriate because an allocation of the compensation of the Chairman of the Board and the President of DRI between DRI and the Company is performed. The evidence shows that these two individuals are employees of DRI. DRI, besides being the parent company of VEPCO, has many separate business interests. The salaries of these individuals are allocated to these business interests in accordance with their activities attributable to each interest. Mr. Maness testified that the amount of compensation allocated to VEPCO was at an executive level. These two individuals held executive-level positions at VEPCO, as Chairman of the Board of Directors and a member of the Board of Directors. The Commission has concluded that the compensation paid by VEPCO to or on behalf of these individuals, after allocation by DRI, should be considered and evaluated as compensation paid to executives of VEPCO. The fact that there is additional compensation paid to these individuals by DRI, attributable to DRI's other business interests, is completely irrelevant to the question of the treatment of their VEPCO compensation.

The Commission also rejects the Company's contention that the interests of the ratepayers and the stockholder are identical. While those interests may converge in some areas, such as the protection of the financial health of the Company, the Commission agrees with Mr. Maness' testimony that the interests often diverge with regard to the issue of profitability. Were it not so, general rate cases might well not ever occur, or alternatively, the revenue increases requested by the Company would always be approved without alteration. The fact that the interests of the stockholder and ratepayers do at times diverge, resulting in the need for Commission oversight, was alluded to by counsel for the Company during this exchange with Public Staff witness Maness:

Q. AND, OF COURSE, THE CAPITAL SUPPLIED BY THAT SOLE COMMON STOCKHOLDER IS A PRETTY ESSENTIAL NEED AS FAR AS THE COMPANY IS CONCERNED, IN MEETING THE DEMANDS OF ITS CUSTOMERS; YOU WOULD AGREE WITH THAT, WOULDN'T YOU?

A. I would agree with that and that capital is certainly supplied with the objective of achieving a profitable operation.

Q. AND YOU WOULDN'T HAVE A PROBLEM WITH A PROFITABLE OPERATION, I WOULD HOPE, WOULD YOU, MR. MANESS?

A. No, but to a certain extent the objective to maximize the profit of the Company may work counter to the best interests of the ratepayers in low and reasonable rates.

Q. WELL, I THINK YOU AND THE COMMISSION WILL SEE THAT IS NO PROBLEM, WON'T YOU?

A. Hopefully so, yes.

The next Public Staff adjustment concerns fringe benefits. The $(30,000) difference in the amounts proposed by the Company and the Public Staff is related to the treatment of the gain from the Equitable settlement. The Commission has fully discussed this issue in the Evidence and Conclusions for Findings of Fact Nos. 14-19 and finds, therefore, that the Public Staff adjustment of $(30,000) is appropriate.

The final difference between the parties with respect to operation and maintenance expense in the amount of $33,000 relates to the extraordinary costs of the Surry outage. As set forth in the Evidence and Conclusions for Findings of Fact Nos. 14-19, the Company and the Public Staff have both proposed an adjustment, which has been accepted by the Commission, to amortize over a three-year period the extraordinary costs related to the lengthy outage at the Surry plant experienced during 1988 and 1989.

The Company proposes to amortize the Surry outage costs incurred during the 1989 test year over a three-year period whereas the Public Staff proposes to amortize those extraordinary costs experienced in 1988 and 1989. Witness Maness testified that he chose to include that amount simply to utilize the total extraordinary cost related to the outage. He stated that it would have also been reasonable to use a lower number and a shorter allocation period to reach a normalized level.

The Commission, as heretofore mentioned, has adopted the adjustment to amortize the extraordinary Surry outage costs. In so doing, the Commission's objective is to normalize expenses, not set aside specific costs incurred in the past for future recovery. The Surry outage costs were incurred in 1988 and 1989; the rates set in this proceeding will be effective in 1991 and future years, unless changed. The test year of 1989 is being used in this proceeding as a model to set rates to be charged on a prospective basis. The Commission is not setting rates today to recover specific costs incurred in 1988 or 1989, even if those costs were abnormally high. The Commission is using 1989 costs as a basis on which to determine rates to be charged in 1991 and future years. In so doing, the costs incurred in 1989 must be adjusted to reflect a normalized level. That normalization is the objective of the Commission's adjustment to Surry expenses.

Accordingly, the Commission concludes that the adjustment as proposed by the Public Staff regarding the amortization of the Surry outage costs is appropriate and should be adopted in order to establish a reasonable and representative level of operation and maintenance expense.

In summary, the Commission concludes that the Company proposed level of operations and maintenance expense should be reduced for ratemaking purposes by $59,000, and that the level of operations and maintenance expense appropriate for use in this proceeding is $59,652,000.

Depreciation and Amortization Expenses

The second area of quantitative difference between the Company and the Public Staff is in the area of depreciation and amortization expense. The $(516,000) difference is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Removal of accelerated depreciation of North Anna Unit steam generators	$ (71)
Adjustment to the North Anna Unit 3 amortization	(137)
Transfer of the North Anna Unit 4 amortization to a tax refund offset	(308)
Total	$ (516)

The first Public Staff adjustment consists of the reversal of the Company's proposed accelerated depreciation on the steam generat..rs for the North Anna 1 nuclear unit. The Company is scheduled to replace the North Anna Unit 1 steam generators in the fourth quarter of 1995. This replacement is due to unforseen, excessive corrosion. The Company installed the steam generators in 1978 and most recently has been depreciating them based on an assumed estimated useful life of 40 years. Initially, the Company took the position that depreciation expense should be accelerated in order to recover all of the remaining costs of the steam generators (plus estimated costs of removal) by the expected date of early retirement (1995). Mr. Bolton testified that this treatment would ensure that the ratepayers receiving the current benefit of the steam generators would pay for that benefit. Public Staff witness Maness testified that any acceleration of depreciation would place an unreasonable burden on the ratepayers served between 1990 and 1995. These ratepayers would be expected to bear the entire deficiency in depreciation recovery resulting from the fact that depreciation charges were, in hindsight, too low in prior years. In Mr. Maness' view, this burden would be inappropriate because the ratepayers served between 1990 and 1995 are not identical to the group of ratepayers served prior to 1990, who received the unwarranted benefit of lower depreciation charges. Mr. Maness testified that continuing the current depreciation rate for the steam generators, which would spread the recovery of the cost and the cost of removal over the remaining life of the North Anna plant, would be more reasonable and appropriate than singling out the ratepayers between 1990 and 1995 to bear the entire remaining cost. He further testified that this treatment is consistent with that given the early retirement of steam generators at the Surry Nuclear Units 1 and 2 in prior cases.

Mr. Bolton compared this situation to a life extension of the Company's nuclear units. In such a situation, he maintained, customers prior to the extension would pay a higher level of depreciation expense than customers subsequent to the extension. The benefit of the higher recovery of depreciation expense in prior years is spread over the remaining life of the asset in the years after life extension. This is a necessary result of the methods used to determine depreciation expense. In Mr. Bolton's view, this logic should be applied to the steam generators in the same way it is applied to nuclear plants as a whole.

In rebuttal, the Company modified its proposal. Company witness Bolton proposed that rather than charging ratepayers in the 1991 to 1995 period the entire remaining cost of the steam generators, the ratepayers between 1991 and 1995 should be charged depreciation expense equivalent to the level that would have been charged had the useful life of the steam generators been correctly estimated from the beginning. The deficiency remaining after 1995 would be dealt with in a future proceeding. Mr. Bolton testified that although the Company continued to believe that the cost of the steam generators should be entirely borne by the ratepayers who were served by it, he viewed the modified Company proposal as a reasonable compromise which would take into account the Public Staff's concern about unreasonably burdening the 1991-1995 ratepayers.

In analyzing this issue the Commission notes that the differences between the parties is one of timing, and that reasonable arguments can be made supporting different positions. The earlier group of ratepayers between 1978 and 1990 paid depreciation expense based on the best known estimate of service life available. They were no more responsible for the depreciation deficit for the steam generators than the earlier generation of ratepayers were responsible for the excess recovery of depreciation expense recovered on the nuclear units.

Clearly, if the facts in this case had been different and the service lives of the generators were to be extended, it would be appropriate and fair to spread recovery of the remaining unrecovered costs over a longer period, thereby reducing the depreciation to be recovered in this case. Fairness supports increasing the depreciation expense when service lives are shortened.

The Commission recognizes as valid the ratemaking principle behind the Company position that costs of the steam generators should be recovered from the customers who receive service from them. Also, under the Public Staff approach, customers receiving service after 1995 will be paying depreciation expense for both the old, retired steam generators and the new, replacement ones. Of course, these post-1995 customers will be receiving service only from the new generators. Fairness to those customers requires that current customers pay for the old generators before they are retired.

Although the cost of the Surry steam generators, which also were retired early due to excessive corrosion, is being recovered over the life of the Surry units, the Company had no advance notice that it would be necessary to replace these generators. There was no practical opportunity to increase the level of depreciation recovered over a remaining useful life. The Surry steam generators were some of the first to be replaced due to the industry-wide corrosion problem. The facts surrounding the Surry steam generator retirement are altogether different from those surrounding the North Anna No. 1 retirement.

The Commission will accept the compromise position set forth by the Company in its rebuttal testimony. This compromise strikes a fair balance between the interests of the ratepayer and the stockholder. Accordingly, the adjustment proposed by the Public Staff in the amount of $(71,000) should be rejected.

The second Public Staff adjustment to depreciation and amortization expense is its adjustment to the factors used to allocate the amortization of the North Anna Unit 3 abandonment loss to North Carolina retail operations. The basic issue of difference between the parties is whether the amortization of the North Anna Unit 3 abandonment loss should be allocated by test year allocation factors or by a weighted average of historical allocation factors from past years. Public Staff witness Maness testified that he calculated the system amount of amortization expense appropriate for the test year, and then allocated that amount to N.C. retail operations using the test year allocation factors recommended for use in this case by the Public Staff. The Company allocated the amortization to N.C. retail operations by using a weighted average of certain allocation factors calculated for years in the interim between the Company's last general rate case and this proceeding.

Mr. Maness offered three reasons for his recommendation to allocate the amortization by current allocation factors. First, he argued that use of the allocation factors related to the test year in this case is consistent with the Commission's conclusion regarding allocation factors in two recent CP&L general rate cases, Docket No. E-2, Subs 526 and 537. In those cases, the Commission ordered CP&L to utilize the allocation factors determined in the course of those proceedings in the calculation of levelized purchased capacity expenses, rather than what the factors were projected to be in future years. Mr. Maness testified that these cases support his contention that "it is generally inappropriate to use past or future allocation factors which have not been subject to Commission review and approval, as part of the ratemaking process to set or influence rates set in a succeeding rate case." The allocation factors used by the Company for the North Anna Unit 3 amortization include factors from 1984 and 1986, factors which were not subject to review as part of a general rate case. For this reason, Mr. Maness testified, the Company's factors should not be used.

Second, Mr. Maness testified that the Public Staff utilization of the test year allocation factors produces the "appropriate allocation of system costs (including abandoned plant amortization) to the N.C. retail jurisdiction on a going-forward basis." Mr. Maness pointed out that the Company's cost are recorded on its books on a system basis and it is essentially only in rate cases that the costs get jurisdictionally allocated in order to set rates. Additionally, the Commission normally sets rates by determining costs on a system basis and then allocating them to the N.C. retail jurisdiction. Mr. Maness testified that the annual amortization of North Anna Unit 3 costs is analogous to accumulated depreciation. Accumulated depreciation is determined on a system basis and allocated to the N.C. retail jurisdiction using the current allocation factors. If the Company's methodology for determining the North Anna Unit 3 amortization were to be applied to accumulated depreciation, N.C. retail accumulated depreciation in this rate case would be determined by summing individual years' system depreciation expense amounts multiplied by individual years' allocation factors. According to Mr. Maness, that is not the manner in which rates have been traditionally set in this jurisdiction.

Third, Mr. Maness testified that when the Commission authorized the amortization of the North Anna Unit 3 abandonment in 1983, it did not order that a specific dollar amount on a jurisdictional basis be recovered for ten years, but instead ordered that the North Anna abandonment loss should be amortized over a ten-year period for ratemaking purposes.

Company witness Bolton testified that the historical allocation factors recommended by the Company distribute costs based more closely on the circumstances that existed at the time the abandonments occurred. Mr. Bolton testified that the Company adjusted the allocation factors that existed at the time of the abandonment loss for the effects of two subsequent material events: (1) the partial sale of the North Anna nuclear facility in 1984; and (2) a later reduction in load by a cooperative customer of the Company. Mr. Bolton stated that the Company has essentially "frozen" the allocation of North Anna Unit 3 costs to all its jurisdictions based on the historical allocation factors adjusted for those two events. Mr. Maness testified, and Mr. Bolton accepted during cross-examination, that the factors used by the Company to allocate the North Anna Unit 3 amortization actually come from allocation studies for three different years - 1982, 1984, and 1986. Mr. Bolton also agreed during cross-examination that the test year factors recommended for use by the Public Staff also include the effect of the two subsequent events that the Company built into its allocation.

Mr. Bolton also testified that "the Commission established at the time of abandonment the total level of costs to be recovered from North Carolina customers over a 10 year period based on the allocation factors at that time." The Company asserts that this supports the use of fixed historical allocation factors rather than the test year allocation factors recommended by the Public Staff.

Mr. Bolton challenged the Public Staff's use of the CP&L decisions to support its positions. He testified that a key distinction is that the Commission rejected CP&L's intended use of projected allocation factors. In his view, the Company's use of historical allocation factors, based on actual booked numbers and a previously approved allocation methodology, distinguishes this issue from the issue addressed in the CP&L cases. Mr. Maness testified, however, that the key point he wished to illustrate by citing those cases is that allocation factors are determined by the Commission in the course of a rate case in order to allocate system costs for ratemaking purposes. It was not appropriate to utilize factors to allocate North Anna Unit 3 costs that were drawn from various allocation studies throughout the 1980's which were not used as part of a rate proceeding.

After careful consideration of this issue, the Commission concludes that the Public Staff's position is proper and reasonable. As is the case for most items of expense and rate base, the Commission concludes that the appropriate method by which to determine the N.C. retail portion of the North Anna Unit 3 amortization for purposes of setting rates in this proceeding is to multiply the system level of amortization by the allocation factors drawn from the test year used in this proceeding. The Public Staff methodology properly allocates the amortization of the North Anna Unit 3 loss in accordance with the test year apportionment of demand and energy between the various jurisdictions.

The Company argues that the historical allocation factors better mirror the circumstances of the time period when the abandonment occurred. The Commission concludes, however, that no substantive link has been demonstrated between the allocation factors at the time of abandonment and the abandonment itself which would make necessary or appropriate the use of those particular allocation factors to allocate the amortization of the abandonment loss in all future periods. Moreover, it is difficult for the Company's argument to carry any weight when the Company itself departed from the allocation factors at the time of the abandonment by using factors drawn from 1984 and 1986 studies. Those allocation factors reflect more changes than just the two subsequent events noted by the Company. They reflect all of the changes in basis of allocation occurring since the time of the abandonment.

The Commission also finds to be inaccurate the Company's contention that the Commission established, at the time of abandonment, the total jurisdictional amount of loss to be collected from the North Carolina retail ratepayers over a ten-year period. In its Order Granting Partial Increase in Rates in Docket No. E-22, Sub 273, in which the Commission first addressed the North Anna Unit 3 loss, the Commission stated the following:

> Based upon a careful consideration of the evidence of record in this case, the Commission finds and concludes that a 10-year period is a reasonable period and should be used for the amortization of the North Anna Unit 3 cancellation costs. Furthermore, the Commission concludes that amortization of the losses resulting from Vepco's cancellation of its Surry Units 3 and 4 and North Anna Unit 4 should be continued over 10 years as previously ordered by the Commission. Utilization of a 10-year amortization period is proper and fair in this proceeding for the reason that such an amortization period, particularly when considered in conjunction with the Commission's decision as subsequently discussed, to allow Vepco no return on the unamortized balance, will serve to more reasonably and equitably share the burden of such plant cancellations between the Company's shareholders and its present and future ratepayers.

Seventy-Third Report of the North Carolina Utilities Commission Orders and Decisions 343, 355 (December 5, 1983)

and

> Since the Commission adopted, in Finding of Fact No. 6, a 10-year amortization of the North Anna 3 loss without rate base inclusion, the Commission concludes that $3,215,000 is the proper level of amortization of property losses.

Id. at 365.

The Commission thus did not determine the total jurisdictional amount of loss to be recovered from the ratepayers in the Sub 273 proceeding. The Commission, instead, concluded that a 10-year amortization period is reasonable. Based on that conclusion, and the costs presented to the Commission at that time, the Commission concluded that $3,215,000 should be included in expenses as amortization of property losses in that proceeding. The Commission's intent in the Sub 273 proceeding was to conclude as to the reasonableness of a 10-year amortization period, not to establish a fixed jurisdictional amortization expense or fixed allocation factors for future years.

Finally, the Commission concludes that the CP&L cases cited by the Public Staff to support its position are relevant to the issue addressed in this case. In Docket No. E-2, Sub 537, the Commission stated as follows:

> Determining the appropriate allocation factors is a complex process. Not only does one of many cost allocation methodologies have to be chosen, but potential adjustments to the allocation factors derived under that methodology must be considered and evaluated. Moreover, the appropriate cost allocation methodologies and adjustments to the allocation factors, as well as the appropriate application of those factors to the cost of service, may change over time. In short, the appropriate allocation factors are determined by the Commission as an integral part of the ratemaking process.

Seventy-Eighth Report of the North Carolina Utilities Commission Orders and Decisions 238, 371 (August 5, 1988) (emphasis added).

Additionally, in Docket No. E-2, Sub 526, the Commission stated, "...an allocation factor is not an independently existing entity outside of a Commission proceeding." Seventy-Seventh Report of the North Carolina Utilities Commission Orders and Decisions 272, 296 (August 27, 1987). The Commission continues to believe that the allocation factors used in a general rate case proceeding should be those that have been subjected to a thorough evaluation by the Commission, usually in the course of a general rate case proceeding. The 1984 and 1986 factors used by the Company do not meet that criterion. The fact that they are historical factors rather than projected factors does not distinguish this case from the CP&L cases cited.

The Commission thus concludes that the Public Staff adjustment of $(137,000) to the North Anna Unit 3 abandonment loss amortization is appropriate.

The third and final adjustment to depreciation and amortization expense recommended by the Public Staff is the removal of the North Anna Unit 4 abandonment loss amortization expense from operating revenue deductions. The remaining unamortized balance (approximately seven months worth of amortization at December 31, 1990) would be recovered, under the Public Staff's proposal, as an offset to the excess deferred income tax refund addressed elsewhere in this Order. Public Staff witness Maness testified that since the remaining amortization period is less than one year in length, its end would not be accompanied by the appropriate reduction in rates if the expense was included in operating expenses.

Company witness Bolton testified that it is more appropriate to include the amortization expense in base rates, because that is consistent with the treatment afforded other cost of service items. During cross-examination of Mr. Maness, the Company asserted that the Public Staff recommendation with regard to North Anna Unit 4 is inconsistent with the treatment of other expenses, particularly the North Anna Unit 3 loss, where both the Company and the Public Staff began amortizing additional costs incurred between the prior rate case and this rate case when those costs were incurred, rather than when the rates in this proceeding are to go in effect. However, Public Staff witness Maness testified that North Anna Unit 4 is a unique situation in which a Commission ordered ten-year amortization period is coming to an end within a year of the effective date of the rates. In his opinion, those circumstances justify the Public Staff's recommended treatment. Additionally, he testified that if the North Anna Unit 4 amortization was simply included in expenses, expenses would not be set at a representative level, since the amortization will cease to exist six or seven months after the rates go into effect.

Company witness Bolton also testified in rebuttal that since the Company was proposing a lump sum excess deferred tax refund rather than a rider refund, there would be no rider against which the remaining North Anna Unit 4 cost could be offset. However, during cross-examination, Mr. Bolton testified that a lump-sum treatment could be afforded the North Anna cost as well, absent any legal restriction.

The Commission concludes that the remaining partial year of the North Anna Unit 4 loss amortization should be recovered as an offset to the refund of excess deferred income taxes addressed elsewhere in this Order. The circumstances presented by this rate case are unique, in that it is known that the amortization period for this loss will end very shortly after the rates set in this proceeding go into effect. In order to set rates which are fair and reasonable, the Commission must strive to determine a representative level of operating revenue deductions. Since the amortization of North Anna Unit 4 ends so soon after the effective date of the rates, inclusion of the remaining cost in operating revenue deductions would result in a non-representative level of operating revenue deductions. Therefore, the Commission is presented with three options regarding this cost: exclude it entirely from rates, amortize it over a longer period of time, or allow recovery as an offset to the tax refund amount. The Commission feels that complete exclusion is not fair to the Company. Amortization over a longer period of time would provide recovery for the Company, but the Commission does not wish to extend the amortization period beyond the ten years ordered if it can be reasonably avoided. Inclusion of the cost as an offset to the deferred tax refund rider provides recovery of the cost and does not necessitate the extension of the amortization period. The Commission thus finds that approach to be the most appropriate of the three possibilities.

Therefore, the Commission concludes that the adjustment recommended by the Public Staff of $(308,000) is appropriate. In summary, the Commission concludes that the appropriate level of depreciation and amortization expense for use in this proceeding is $19,848,000.

Other Taxes

The third area of quantitative difference between the Company and the Public Staff relates to taxes other than income taxes. The difference of $(129,000) between the parties is composed of the following Public Staff adjustments:

(000's Omitted)

Item	Amount
Reclassification of state income taxes	$ (53)
Adjustment to remove sales and use tax adjustment	(76)
Total	$ (129)

The first Public Staff adjustment results from the reclassification of state income taxes from the "other taxes" category to the "income taxes" category. This adjustment has no net effect on the revenue requirement. The Commission concludes that this adjustment is appropriate.

The other Public Staff adjustment, a reduction of $(76,000), concerns Virginia sales and use taxes. Public Staff witness Maness proposed an adjustment to eliminate a Virginia sales and use tax assessment from operating revenue deductions. According to Mr. Maness' testimony, this tax assessment relates to the years 1985, 1986, and 1987 and rates should not be set to recover prior expenses. He also testified that the Company does not anticipate another sales and use tax assessment of this magnitude.

Company witness Bolton argued in rebuttal testimony that although the level of sales and use tax expense related to the assessment is non-recurring, it should be afforded a three-year amortization. Mr. Bolton cast the assessment in the light of a true-up of a prior estimate to the actual cost level. He stated that if the ultimate tax liability differs from the assessment included in expenses, the Company will adjust cost of service in a future period.

During cross-examination on rebuttal, Mr. Bolton agreed that the assessment relates to prior years, and is non-recurring. He also agreed that the level of sales tax in 1989, including the assessment, was abnormal. Mr. Bolton also accepted that the Company had responded to a Public Staff data request by stating the 1989 sales and use tax expense, excluding the assessment, was based on an improved accounting system which will better identify taxable items, and that the Company does not anticipate another assessment of this magnitude.

The Commission concludes that the amortization of the sales and use tax assessment is not properly included in the cost of service. The Commission concludes that the ultimate amount of the assessment and the timing of any payment are not known. The Company's promise to adjust the assessment to actual amounts in a future period does not adequately protect the ratepayer, since that future period might not be one on which future rates are based. Furthermore, based on the data response of the Company the Commission concludes that the actual or current period level of sales and use tax expense for 1989 is representative of an on-going level of expenses. Therefore, the Commission concludes that O&M expenses should be reduced by $(76,000).

In summary, therefore, the Commission concludes that the appropriate level of other taxes for use in this proceeding is $9,740,000.

Income Taxes

The fourth area of quantitative difference between the Company and the Public Staff in the amount of $672,000 relates to income taxes.

The Commission has concluded elsewhere that the reclassification of state income taxes in the amount of $53,000 from the "other taxes" category is appropriate.

The remaining Public Staff adjustments to income taxes result from the other Public Staff adjustments to revenue and expenses as well as its recommended capital structure, cost rates and rate base. Based on its findings elsewhere in this Order, the Commission concludes that adjustments of $252,000 are appropriate.

In summary, the Commission concludes that the level of income tax expense appropriate for use in this proceeding is $7,184,000.

Charitable Contributions

The fifth area of quantitative difference concerns charitable and educational contributions. Public Staff witness Maness testified that charitable and educational donations are not a necessary cost of providing utility service. Additionally, he stated that the ratepayers should not involuntarily be required to pay in costs for contributions selected by the Company rather than the ratepayers.

Company witness Bolton stated in rebuttal testimony that the Company contributes funds to many charities and educational institutions as a part of its corporate policy. He stated it was important for businesses to continue to support charitable and educational institutions so that a reduction in service does not occur. Mr. Bolton stated that at least an equal sharing of these costs between ratepayers and shareholders should be allowed.

Witness Bolton, on cross-examination, did acknowledge that VEPCO, in its proposed order in Docket No. E-22, Sub 303, a complaint proceeding, took the position that involuntary charitable contributions should not be charged to ratepayers.

The Commission agrees that charitable and educational donations should not be included in the cost of service. It has been a long-standing policy of this Commission to exclude contributions from operating expenses. The Commission finds it appropriate to decrease operating revenue deductions by $70,000 to eliminate charitable contributions from the cost of service.

Based upon the Commission's conclusions set forth herein, the Commission finds that the level of operating revenue deductions, excluding fuel expenses, appropriate for use in this proceeding is $96,648,000, calculated as follows:

(000's Omitted)

Item	Amount
Operation and maintenance expense	$59,652
Depreciation and amortization	19,848
Other taxes	9,740
Income taxes	7,184
Interest on customer deposits	133
Interest on tax deficiencies	91
Total	$96,648

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 56

The evidence for this finding of fact is found in the testimony and exhibits of Company witnesses Leidheiser and Bolton and Public Staff witness O'Donnell. The following table presents the final positions of the Company and the Public Staff on the capital structure issue.

	Company	Public Staff
Long-Term Debt	49.53%	49.84%
Preferred Stock	9.63%	9.69%
Common Equity	40.62%	40.25%
Other Paid-In Capital	.22%	.22%
Total	100.00%	100.00%

Both parties agree that the Commission should use the Company's capital structure as of September 30, 1990. The only difference between the capital structures finally recommended by the Company and the Public Staff is the treatment of the retained earnings that relate to Statement of Financial Accounting Standards No. 90, Regulated Enterprises--Accounting for Abandonments and Disallowances of Plant Costs (SFAS No. 90).

Public Staff witness O'Donnell recommended that the Commission adjust the capital structure recommended by the Company to remove all retained earnings that relate to SFAS No. 90. Mr. O'Donnell testified that SFAS No. 90 requires the utility to remove from retained earnings the present value of the cash return that is to be earned on the unamortized balance of terminated construction project costs.

Company witness Bolton testified in rebuttal that the Company's adoption of SFAS No. 90 created non-cash losses in the years of plant abandonments and that these losses had reduced the Company's per books balance of retained earnings. Nevertheless, he argued that SFAS No. 90 should be ignored for the purposes of ratemaking and that the effects of SFAS No. 90 should be removed from the cost of capital and capital structure.

Mr. Bolton testified that the Company had implemented SFAS No. 90 in 1986 by restating financial statements for prior fiscal years. He stressed that SFAS No. 90 required the Company to recognize the loss of abandoned plant for financial reporting purposes, but noted that it did not alter the Commission's previously established treatment of abandonment losses for ratemaking purposes. Mr. Bolton argued that failure to reverse the impact of SFAS No. 90 for ratemaking purposes would alter the Commission's previous decisions on abandoned plant and would increase the loss of the Company above the level intended by the Commission.

The Commission has carefully considered the evidence presented regarding the treatment of the effects of SFAS No. 90. Based upon this thorough examination, the Commission has determined that for ratemaking purposes the impact of SFAS No. 90 should be reversed. The Commission previously has held that for the purpose of ratemaking shareholders and ratepayers should share the cost of nuclear abandonments. This sharing was to be accomplished through the utility's recovery of abandonment costs over a ten-year period without a return on the unrecovered balance. As a result, for ratemaking purposes a utility's shareholders recognize a loss ratably over the ten-year amortization period.

Contrary to the Public Staff's position, SFAS No. 90 does not and should not alter the Commission's ratemaking treatment of abandonment costs. As Mr. Bolton testified, SFAS No. 90 merely accelerates the shareholder's loss for financial reporting purposes through a reduction in the utility's retained earnings by the difference between the unamortized abandonment costs and the present value of future revenues representing the recovery of these costs. As a result, shareholders recognize the loss of return on abandoned plant immediately for financial reporting purposes.

Nevertheless, for ratemaking purposes, the Commission concludes that the effects of SFAS No. 90 should be reversed so that the shareholder will recognize the disallowed carrying costs ratably over the ten-year amortization period as previously mandated by the Commission. Failure to remove the impact of SFAS No. 90 from cost of capital and capital structure in contravention of Commission precedent will penalize the Company by increasing the loss it suffers above the level intended by the Commission. The Commission does not believe that such penalty is equitable or warranted. The Commission, therefore, finds and concludes that the capital structure proposed by the Company, as reflected hereinabove, is appropriate for use herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 57-62

The evidence for these findings is contained in the testimony and exhibits of Company witnesses Leidheiser and Avera and Public Staff witness O'Donnell.

The Company and Public Staff were in agreement on the proper cost rates of preferred stock, long-term debt, and other paid-in capital to be employed in this case. Both parties agree that the Commission should employ the September 30, 1990, Virginia Electric and Power Company embedded cost rates. These cost rates are as follows:

Long-Term Debt	8.84%
Preferred Stock	7.53%
Other Paid-In Capital	0.00%

The Company and Public Staff were not in agreement on the proper investor return requirement for common equity. Company witness Avera recommended that the Commission recognize 13.25% as the cost of equity to Virginia Electric and Power Company in this case. Public Staff witness O'Donnell recommended that the Commission recognize 12.52% as the cost of common equity for the Company in this case.

In his pre-filed testimony, Company witness Avera employed three different methods in his cost of equity analysis. Dr. Avera employed the constant growth DCF model, the non-constant growth DCF model, and the risk premium method in his return on equity recommendation.

In applying the constant growth DCF model, Dr. Avera studied forty companies which he felt were comparable in risk to Dominion Resources, the parent holding company of Virginia Electric and Power Company. Dr. Avera used Dominion Resources as a proxy for Virginia Electric and Power Company since Virginia Electric and Power Company has no publicly traded common stock as does Dominion Resources. Using the constant growth DCF model, witness Avera determined that the investor return requirement was in the range of 11.5% to 12.5% for Dominion Resources and 11.0% to 12.0% for the comparable group. Employing the non-constant growth DCF model, Dr. Avera found the Dominion Resources cost of equity to be 13.10% and 13.52% for the comparable group. Using the risk premium method, Dr. Avera found 14.62% as the Virginia Electric and Power cost of equity and 14.60% as the comparable group's cost of equity.

From the results of his three methods, Dr. Avera concluded that the cost of equity to Virginia Electric and Power Company was in the range of 13.0% to 13.50%. His final cost of equity recommendation to the Commission was 13.25%.

Public Staff witness O'Donnell employed two different cost of equity methods in his analysis of the investor return requirement for Virginia Electric and Power Company. As a proxy for Virginia Electric and Power Company, Mr. O'Donnell also employed common stock data for Dominion Resources in his cost of equity analysis.

The first method witness O'Donnell employed in his analysis was the constant growth DCF model. He performed a DCF analysis on Dominion Resources as well as on a group of electric utilities which are similar in risk to Dominion Resources. From this model, Mr. O'Donnell determined the investor return requirement to Dominion Resources to be in the range of 12.05% to 12.55%. For the comparable group, Mr. O'Donnell found the cost of equity to be in the range of 12.10% to 12.60%. Based upon the comparable earnings method, Mr. O'Donnell determined the Virginia Electric and Power Company cost of equity to be in the range of 12.25% to 13.25%.

In determining his final cost of equity recommendation, Mr. O'Donnell stated that he relied more heavily on his DCF analysis than his comparable earnings analysis. He concluded that the current investor return requirement to Virginia Electric and Power was in the range of 12.25% to 12.75% and recommended that the Commission recognize 12.50% as the investor required return on equity for the Company. Mr. O'Donnell also added .02% to his return on equity recommendation to account for the Company's selling expense incurred for issuing new common stock. Witness O'Donnell determined his flotation cost adjustment by estimating a weighted average selling expense as a percent of book equity based upon the issuance cost incurred on public issues of Dominion Resources' common stock since 1980. Mr. O'Donnell estimated this weighted average cost rate to be .07%. However, because Dominion Resources had only issued stock three times in the past ten years, he testified that the proper adjustment for flotation costs was .02% (3/10 x .07%). Mr. O'Donnell thus adjusted his recommendation for cost of equity of 12.50% by two basis points to provide an allowance for issuance costs. Mr. O'Donnell's final cost of equity recommendation to the Commission was 12.52%.

In his pre-filed testimony, Mr. O'Donnell also reviewed the testimony of Company witness Avera. Mr. O'Donnell noted that he disagreed with Dr. Avera's use of two versions of the DCF model. Since Dr. Avera did not test the validity of the non-constant growth DCF model as he did the constant growth DCF, Mr. O'Donnell tested the non-constant growth DCF. Mr. O'Donnell tested the non-constant growth DCF in the exact same manner as Dr. Avera's test of the constant growth DCF. Based upon the results of both studies, Mr. O'Donnell concluded that the constant growth DCF was the superior cost of equity method.

As an alternative to the risk premium studies presented by Dr. Avera, Mr. O'Donnell cited the yearly risk premium between allowed returns on equity and yields on single A-rated utility bonds from 1976 to 1990 for the Salomon Brothers' 100 electric utilities. From the data he presented, Mr. O'Donnell concluded that the electric utility equity risk premium was in the range of 250 to 350 basis points, which he noted was substantially lower than the 470 point spread Dr. Avera employed in his testimony.

Dr. Avera also filed rebuttal testimony in this proceeding. In his rebuttal testimony, Dr. Avera criticized Mr. O'Donnell's use of the constant growth DCF model contending that this model produces illogical and unreliable cost of equity estimates. Dr. Avera also criticized Mr. O'Donnell for not employing current bond yields in his cost of equity analysis. Finally, Dr. Avera contended that Mr. O'Donnell's flotation cost adjustment underestimated the cost the Company has incurred to issue common stock. Dr. Avera asserted that the true flotation cost adjustment was 33 basis points.

During cross-examination, Company witness Avera was questioned extensively on the calculated return on equity derived from his version of the non-constant growth DCF model. Dr. Avera acknowledged that when simply updating to the time of the hearing, his version of the non-constant growth DCF model yielded a return on equity of 9.70%. Dr. Avera also acknowledged that during the six-month time period prior to the hearing, the return on equity calculated from his version of the non-constant growth DCF model fell over 3.0% to 9.70%. Witness Avera further agreed that the results obtained from his version of the non-constant growth DCF model varied widely. Public Staff Avera Cross-Examination Exhibit No. 6 showed that the non-constant growth DCF model produced returns on equity ranging from 9.70% to 17.09%. The 7.39% return on equity spread was the result of employing various historical price to earnings (P/E) ratios with the non-constant growth

DCF. Dr. Avera rejected the resulting return on equity range, claiming that the calculated return results must be, in his opinion, logical. He stated that there were multiple ways to apply the non-constant growth DCF and agreed that the version of the non-constant growth DCF that he used in this case may not be appropriate for use on any other day.

Dr. Avera was also asked several questions regarding his empirical test of the constant growth DCF model. From the results of this test, Dr. Avera concluded that in 1988 and 1989 the constant growth DCF produced results that were illogical and unreliable. Dr. Avera admitted that he drew this conclusion even though his test results were not statistically significant.

Witness Avera was also extensively cross-examined on his application of the risk premium method in this case. Dr. Avera testified that the risk premium method does not provide precise return on equity figures. Dr. Avera also acknowledged that the Ibbottson and Sinquefield study he presented in his pre-filed testimony was the only study which was based on long-term historical returns. The time period covered in this study spanned from 1926 through 1987 and included three wars, several periods of wage and price control, inflationary and deflationary periods, and several stock market crashes. This study did not, however, cover the three most recent years of our history, 1988 through 1990. Dr. Avera stated that a study covering 1926 through 1987 was a good judge for measuring the risk premiums for Virginia Electric and Power over the next few years.

In his pre-filed testimony, Dr. Avera cited a risk premium study conducted by Charles A. Benore of the investment advisory firm of Paine, Webber, Mitchell Hutchins, Inc. Dr. Avera reported that this study determined that utility equity risk premiums averaged 4.24% over double-A utility debt costs. During cross-examination, Dr. Avera acknowledged that this study also reported equity risk premiums for electric utilities which were not involved in nuclear construction programs. Although this was not cited in his pre-filed testimony, Dr. Avera agreed that the Benore study reported that the risk premium for an electric utility not involved in nuclear construction was approximately 2.6%. Dr. Avera also acknowledged that Virginia Electric and Power Company was not currently in the process of building a nuclear power plant.

Dr. Avera was also asked several questions on the Capital Asset Pricing Model (CAPM). Dr. Avera stated that the value of the CAPM was of great debate within the financial community.

During cross-examination, Dr. Avera was asked several questions regarding his 33 basis point flotation cost adjustment. Public Staff Avera Cross-Examination Exhibit No. 9 showed that a 33 basis point adjustment to the Company's return on equity would result in an annual flotation adjustment of approximately $18.2 million to the Company. Dr. Avera stated that this annual adjustment was proper even though the Company has not incurred any flotation costs in seven years, is not currently incurring flotation costs, and does not plan to incur any flotation costs in the foreseeable future.

Public Staff witness O'Donnell was cross-examined extensively on the mathematical relationship between the constant growth DCF and the non-constant growth DCF. Mr. O'Donnell stated that the difference in the two models was that the non-constant growth DCF terminates at a point in time but the constant growth DCF continues indefinitely. Mr. O'Donnell further stated that the return on equity derived from the non-constant growth DCF varies tremendously due to the variability in the price to earnings ratio which Dr. Avera employed in forecasting a terminal stock price. Mr. O'Donnell also noted that another problem with Dr. Avera's version of the non-constant growth DCF is his reliance on a single Value Line earnings estimate to forecast a terminal stock price.

Mr. O'Donnell also answered several questions concerning the risk premium method. He indicated that the results from this method could easily be manipulated. Mr. O'Donnell stated that one way a person could manipulate the results from the risk premium method was to study different time periods. Since there was available data for 62 years, Mr. O'Donnell testified that there was a different risk premium associated with each possible time period studied.

Mr. O'Donnell criticized Dr. Avera for not studying the most recent years in history. Dr. Avera's studies stopped in 1987 so his analysis contained no risk premium information for the years 1988 through 1990. Mr. O'Donnell stated that as a general tendency investors remember the most recent events more than events that occurred several years ago. By not considering the risk premiums from 1988 through 1990, Dr. Avera has ignored a very important part of current investor expectations.

Mr. O'Donnell also testified that the best way to measure current investor expectations was to employ the DCF method and not the risk premium method. Mr. O'Donnell stated that current economic conditions were vastly different than economic conditions over the period of 1926 to 1987. He stated that the best way to gauge current investor expectations was to consider what investors are currently paying to own utility common stock. Mr. O'Donnell stated that unlike the risk premium method, the DCF method directly incorporates current stock market prices.

The determination of the fair rate of return for the Company is of great importance and must be made with great care because whatever return is allowed will have an immediate impact on the Company, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission, using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4) to

> enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States....

State ex rel. Utilities Comm. v. Duke Power Co., 285 N.C. 377, 388, 206 S.E. 2d 269 (1974).

The Commission is mindful of the fact that its conclusion of the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 699, 370 S.E. 2d 567, 573 (1988).

The Commission has considered carefully all of the relevant evidence presented in this case, with the constant reminder that whatever return is allowed will have an immediate impact on the Company, its stockholders, and its customers and that the Commission must use its impartial judgment to ensure that all parties involved are treated fairly and equitably. Based upon evidence in the record, the Commission finds the following:

(1) The proper capital cost rates are 8.84%, 7.53%, and 0% for long-term debt, preferred stock, and other paid-in capital, respectively. The Company and Public Staff agreed that these cost rates are proper to employ with the Company's September 30, 1990, capital structure. The Commission agrees with the Public Staff and the Company that these cost rates are proper to employ in this proceeding.

(2) Company witness Avera's version of the non-constant growth DCF model and risk premium method as applied in this case should be accorded only minimal weight for purposes of this proceeding. The results calculated from the non-constant growth DCF model are simply too volatile. The Commission notes that the return on equity derived from the non-constant growth DCF fell over 3.0% in the six months prior to the hearing. The Commission also notes that at the time of the hearing, Dr. Avera's version of this model produced a cost of equity of 9.70% to Dominion Resources.

The risk premium method as applied by witness Avera in this case is too easily manipulated. Evidence in the record showed there was a specific risk premium difference between utilities with and without nuclear construction programs. Dr. Avera's analysis failed to consider this risk premium difference. Witness Avera's risk premium analysis also failed to consider that current economic conditions are vastly different from the economic conditions that prevailed from 1926 to 1987.

(3) The constant growth DCF model should be given the greatest weight for purposes of determining the cost of equity capital in this case. Company witness Avera and Public Staff witness O'Donnell both employed this method in this case and their results were almost identical. Dr. Avera's Dominion Resource's constant growth DCF analysis produced a cost of equity in the range of 11.5% to 12.5%. Mr. O'Donnell's DCF analysis in this case produced a cost of equity in the range of 12.05% to 12.55%.

The Commission, for purposes of this proceeding, finds that the constant growth DCF model produces consistent, reasonable, and reliable estimates of the cost of equity and that this model should be given the greatest weight for purposes of determining the cost of equity in this proceeding.

The proper dividend yield to employ in this case is the twenty-six week dividend yield average of April 23, 1990, through October 15, 1990. The weekly dividend yield is calculated by dividing the Value Line weekly forecast of dividends to be paid over the next twelve months by the weekly closing price of the stock. For Dominion Resources, the proper dividend yield to employ in this case is 7.8%.

The two expert witnesses in this case also generally agreed on the long-term growth rate which investors expect for Dominion Resources. Company witness Avera determined that investors expect the Company to grow at a 4.0% to 5.0% yearly rate. Public Staff witness O'Donnell determined the Dominion Resources long-term growth rate to be in the range of 4.25% to 4.75%. The Commission finds the proper long-term growth rate for purposes of this proceeding to be in the range of 4.0% to 5.0%.

Based upon the foregoing, the Commission finds the DCF estimate of the cost of equity for Dominion Resources to be in the range of 11.8% to 12.8%. This range is the sum of the expected dividend yield of 7.8% and the expected long-term growth rate range of 4.0% to 5.0% which we find appropriate for use in this case.

The Comparable Earnings method is also a proper cost of equity method to consider in this case. Investors obviously consider the most recent earned returns of similar investments when making decisions of whether to buy or sell a security. The price of any security reflects in part its historical earnings performance. The comparable earnings in electric utilities and in other regulated and non-regulated industries is in the range of 12.25% to 13.25%.

(4) The investor return requirement to Virginia Electric and Power Company is 12.7%. In reaching this conclusion, the Commission has placed greater weight on estimates of the cost of common equity derived by use of the constant growth DCF model. However, the Commission has also incorporated into its determination in this regard estimates of the cost of equity derived by use of other methodologies advocated by the witnesses. Specifically, the Commission has considered and carefully weighed the evidence related to estimates of the cost of common equity based on the constant growth DCF model, the comparable earnings methodology, the risk premium methodology, and the non-constant growth DCF model. As previously stated, minimal weight has been accorded the evidence relating to the risk premium methodology and the non-constant growth DCF model. Based upon the entire evidence of record, the Commission finds and concludes the proper common equity investor return requirement for purposes of this proceeding to be 12.7%. This return requirement falls within the range recommended by Public Staff witness O'Donnell.

(5) The proper equity flotation cost adjustment to allow Virginia Electric and Power Company is .02%. This adjustment will allow the Company to recover a reasonable and representative level of common equity flotation costs for reasons stated by witness O'Donnell. In essence, this provision for the inclusion of flotation cost in the test-year cost of service reflects a normalization adjustment that is required in order to make the test-year cost of service representative of the levels of cost that the Company can reasonably be expected to experience in the future. The Commission rejects Dr. Avera's 33-basis point flotation cost adjustment. Dr. Avera's adjustment is grossly excessive and is not supported by evidence of record.

(6) The total cost of equity granted to Virginia Electric and Power Company in this case is 12.72%. The total cost of equity found reasonable by the Commission is the sum of the investor return requirement of 12.7% and the flotation cost adjustment of .02%.

(7) The overall fair rate of return which the applicant should be allowed the opportunity to earn on its rate base is 10.27%. Based upon the Commission's findings with respect to the proper capital structure and its findings regarding the appropriate cost rates for each component of capital reflected in said capital structure, the Commission finds and concludes that the overall fair rate of return that the applicant should be allowed an opportunity to earn on its rate base is 10.27%.

Regarding the issue of a fair rate of return there is one final matter which needs to be addressed. In its Proposed Findings of Facts and Conclusions of Law on a Rate of Return Penalty and Stock Flotation Costs, the Attorney General urges the Commission to impose a rate of return penalty of 100 basis points. The Attorney General seeks to impose this penalty so as to penalize the Company for alleged management inattention to performance and safety problems at the Company's Surry plant.

The Attorney General has, however, provided no convincing evidence to support a conclusion that the Surry outages were caused by any management shortcomings. In the Company's last fuel proceeding, Docket No. E-22, Sub 308, the Commission reduced the Company's fuel cost to be recovered through rates by $1.5 million to compensate North Carolina ratepayers for any management inefficiencies which might have caused or magnified the unfavorable consequences associated with the Surry outages. The evidence in this case clearly does not justify any further cost disallowances in this regard. Therefore, based upon the foregoing and all other evidence of record, the Commission finds and concludes that the Attorney General's request for a rate of return penalty should be and hereby is denied.

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 S.E. 2d 547 (1980). State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E. 2d 786 (1982). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. Utilities Commission v. Power Company, 285 N.C. 377, 395 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." Utilities Commission v. Public Staff, 322 N.C. 689, 694, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented (and the weight and credibility thereof) in each case.

The Commission cannot guarantee that North Carolina Power will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rate of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds, and thus concludes, that the rates of return approved herein will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The Commission has previously discussed its findings and conclusions regarding the fair rate of return which North Carolina Power should be afforded an opportunity to earn.

The following schedules summarize the gross revenue (excluding fuel revenue) and the rate of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. Such schedules, illustrating the Company's gross revenue requirement (excluding fuel revenue), incorporate the findings and conclusions heretofore and herein made by the Commission.

SCHEDULE I
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 314
STATEMENT OF OPERATING INCOME[1]
Twelve Months Ended December 31, 1989
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Operating revenue	$122,356	$ 13,916	$136,272
Operating revenue deductions			
Operation & maintenance expense	59,652	36	59,688
Depreciation & amortization	19,848	-	19,848
Other taxes	9,740	447	10,187
Income taxes	7,184	5,207	12,391
Interest on customer deposits	133	-	133
Interest on tax deficiencies	91	-	91
Total operating revenue deductions	$ 96,648	$ 5,690	$102,338
Net operating income	$ 25,708	$ 8,226	$ 33,934

SCHEDULE II
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 314
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1989
(000's Omitted)

Item	Amount
Investment in electric plant	
Electric plant in service including nuclear fuel	$504,804
Accumulated depreciation	(131,522)
Accumulated amortization of nuclear fuel	(25,084)
Accumulated deferred income taxes	(32,488)
Net investment in electric plant	315,710
Allowance for working capital	
Materials and supplies	11,510
Cash working capital	3,393
Total allowance for working capital	14,903
Other cost-free capital	(210)
Original cost rate base	$330,403
Rates of Return	
Present rates	7.78%
Approved rates	10.27%

[1] As noted elsewhere herein, this schedule does not reflect fuel revenues and associated fuel expenses. Based upon the test-year level of operations, the proper level of fuel revenue and fuel related expenses for use herein, after giving effect to the Commission's approved increase, is $29,797,000.

SCHEDULE III
NORTH CAROLINA POWER
North Carolina Retail Operations
Docket No. E-22, Sub 314
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1989
(000's Omitted)

Item	Capitalization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-term debt	49.53%	$163,648	8.84%	$ 14,466
Preferred stock	9.63%	31,818	7.53%	2,396
Common equity	40.62%	134,210	6.59%	8,846
Other paid-in capital	.22%	727	0.00%	0
Total	100.00%	$330,403	-	$ 25,708
	Approved Rates - Original Cost Rate Base			
Long-term debt	49.53%	$163,648	8.84%	$ 14,466
Preferred stock	9.63%	31,818	7.53%	2,396
Common equity	40.62%	134,210	12.72%	17,072
Other paid-in capital	.22%	727	0.00%	0
Total	100.00%	$330,403	-	$ 33,934

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64 .

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Evans, Public Staff witness Turner and CIGFUR witness Phillips. In his direct testimony, Company witness Evans testified that after taking into consideration the increase in revenue from miscellaneous and facilities charges, the remaining basic revenue increase was initially spread among the customer classes (residential, small general service, large general service, and outdoor and street lighting) in order to obtain rates of return within plus or minus 10 percent of the overall proposed jurisdictional rate of return.

The revenue increase proposed by the Company was distributed by witness Evans in order to produce customer class rates of return as follows:

	% return index
Residential	0.916
Small General Service	1.119
Large General Service	1.059
Lighting	1.117
Overall	1.000

Each class return would be closer to the overall rate of return after the increases proposed by witness Evans than before the increases were applied.

Public Staff witness Turner recommended that three criteria be employed in spreading the increase by rate class. First, to the extent possible, rates of return for the class should be plus or minus 10 percent of the overall rate of return. Second, the percentage increase for any class should be no more than two percentage points above the overall percentage increase. Third, the revenue loss associated with customer migration from Schedule 6 to Schedule 6P should be included in or added to the revenue target for the Large General Service Class.

The revenue increase proposed by the Public Staff was distributed by witness Turner in order to produce customer class rates of return as follows:

	% return index
Residential	0.890
Small General Service	1.120
Large General Service	1.087
Lighting	1.374
Overall	1.000

Nevertheless, each class return would be closer to the overall return after the increases proposed by witness Turner than before the increases were applied.

On rebuttal, Company witness Evans disagreed with witness Turner's second criteria that no class should receive a percentage increase greater than two percentage points above the overall percentage increase. Mr. Evans stated that dependant upon the final revenue increase, following this criteria may not allow for the residential classes to be within 10 percent of the overall rate of return.

The second criteria of witness Turner was also opposed by CUCA and by CIGFUR. Witness Phillips pointed out that any increase should result in a meaningful movement of each class return toward the overall return. He suggested that an appropriate movement would be one-half the difference between the class rate of return and the overall rate of return in a given proceeding.

The Commission concludes for purposes of this proceeding that the residential class return should be brought up to at least 90 percent of the overall return even if this means that the increase to that class exceeds the overall percentage increase by more than two percentage points. The Commission finds the Public Staff criteria of plus or minus 10 percent of the overall rate of return somewhat inconsistent with the limitation of a two percentage point increase over the jurisdictional increase. The Commission does not agree that one class return should be set at less than 90 percent of the overall rate of return just because an increase of more than two percentage points above the overall percent increase would be required to correct the imbalance. This violates the goal of requiring each class to bear as nearly as practical its fair share of the cost of service.

The Commission concludes that the revenue increase adopted herein should be distributed in order to produce customer class rates of return as follows:

	% return index
Residential	0.905
Small General Service	1.105
Large General Service	1.085
Lighting	1.150
Overall	1.000

The Commission recognizes that some minor adjustment of the above percent return indices may be necessary to produce the exact overall revenue increase adopted herein, and that such adjustments will not violate the general intent of the Commission reflected in the above indices.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 65

The evidence supporting this finding of fact is contained in the testimony and exhibits of Company witness Evans, Public Staff witness Turner and CIGFUR witness Phillips. Company witness Evans testified that in designing rates an adjustment was necessary to recover the revenue loss associated with customers migrating from Rate Schedule 6 to time-of-use Rate Schedule 6P. In designing its proposed rates, the Company spread this revenue loss to all customer classes to determine the overall increase to be achieved by each class. Mr. Evans testified that the potential revenue loss from customers moving to Rate Schedule 6P is approximately $1,500,000. Of this amount the Company estimates that the loss would be $1,044,000 based on customers that it estimates would actually migrate, and it is this amount the Company proposes to spread to all customers.

Public Staff witness Turner recommends that the loss associated with the migration of customers to Rate Schedule 6P remain with the large general service class. Witness Turner testified that allocating losses attributed to the large general service class to all customer classes serves to move the residential rate of return toward the overall rate of return but also serves to increase the rate of return to the small general service, governmental, and outdoor lighting classes to more than 110 percent of the overall return. Mr. Turner testified that if the predicted revenue erosion actually occurs, the Public Staff proposal serves to maintain large general service revenues at the level approved herein prior to such revenue erosion.

On rebuttal to the Public Staff, Company witness Evans testified that the Company sought to spread the revenue loss from migration to Schedule 6P among all customer classes because it was assumed that once customers begin managing their load on Schedule 6P, all customers would share in the benefit. Witness Evans contended that all customers will benefit from any load reductions from Schedule 6P, and that it is reasonable for all customers to share in the costs associated with obtaining any benefits. He testified that under the Public Staff proposal, much of the revenue loss would be spread back to rate Schedule 6P itself, thus reducing the incentive for customers to transfer to the rate.

On cross-examination, witness Evans agreed that the revenue loss discussed herein due to customer migration was calculated without regard to any actual changes in usage patterns which might occur in response to Schedule 6P, and that the revenue loss calculations are based on the migrating customers simply reaping the benefits of their current usage patterns.

CIGFUR witness Phillips supported the Company's proposal to spread the revenue loss to all rate classes, and cited the Commission's similar treatment of revenue losses due to customer migration in the Duke Power Company rate case in Docket No. E-7, Sub 408.

After examining the evidence presented on this issue, the Commission concludes that the anticipated migration loss should remain within the large general service class. In this proceeding, a correction is already being applied to the respective increase for each customer class in order to achieve more nearly equal rates of return, so that transferring revenues from the large general service class to other customer classes is not needed to help equalize rates of return. Retaining the revenue erosion discussed herein within the large general service class will also be consistent with designing time-of-day rates to be revenue neutral within their respective customer classes, as discussed elsewhere herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence concerning this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Turner. Upon its review of the Company's design of time-of-use rates, the Public Staff recommended that the rates designed for the time-of-use rate schedules for residential and nonresidential customers should be designed on a revenue neutral basis. For example, Schedule 1P rates should be designed to produce revenue equal to the revenue target set for Schedule 1 assuming all customers on Schedule 1 would switch to Schedule 1P. Time-of-use rates, as a result, offer some customers lower bills, some customers higher bills, and some customers would pay about the same depending on the individual customer's load pattern.

No party objected to designing the time-of-use rates to be revenue neutral, except for Schedule 6P as discussed elsewhere herein. The Commission concludes that residential and nonresidential time-of-use rate schedules should be designed to be revenue neutral with their respective corresponding non-time-of-use rate schedules. Revenue neutrality achieves the objective of ensuring that time-of-use rates are cost based and do not result in unreasonable preferences for either time-of-use customers or for non-time-of-use customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 67 AND 68

The evidence for these findings of fact is found in the testimony of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn recommended the inclusion of the following holidays as off-peak periods for residential time-of-use Schedules 1P and 1T and nonresidential time-of-use Schedules 5P and 6P: New Year's Day, Good Friday, Memorial Day, July 4, Labor Day, Thanksgiving (Thursday and Friday), and Christmas Day. Witness Evans accepted the Public Staff recommendations. The Commission concludes that the Public Staff recommendations should be adopted, and that a reasonable period of time should be allowed for the Company to reprogram its meters in order to implement the change.

In connection with his recommendation to classify certain holidays as off-peak days for Schedules 1P, 1T, 5P and 6P, Public Staff witness McLawhorn proposed that the Commission require the Company to study other holidays such as Martin Luther King, Jr. Day for purposes of determining if and when their load characteristics are similar to the holidays found to be off-peak in this proceeding. Mr. McLawhorn recommended that the Commission require the Company to file such analysis with the Commission so that these holidays may be given proper consideration for inclusion as off-peak periods as well.

The Company maintains that such a requirement is unnecessary at this time. Duke and CP&L have determined that the King holiday does not at this time have load characteristics similar to the other holidays designated as off-peak. It is important to maintain some stability and predictability in designing rate schedules. Rate schedules should not be altered more often than reasonably necessary to avoid customer confusion and reprogramming of meters. The Company recommends that no additional holidays be classified as off-peak for five years to avoid or minimize these problems.

The Commission concludes that the Company should prepare a study of other holidays such as Martin Luther King, Jr. Day in order to determine if they are predominantly off-peak, and that the study should be presented to the Commission with the Company's next general rate application.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 69

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn testified that the Company's proposal to make weekend energy charges for Rate Schedule 6P on-peak was inconsistent with the Company's other time-of-use Schedules 1P, 1T, 1W, and 5P, and should be rejected. Witness Evans testified that the Company would accept the Public Staff's recommendation provided qualifying language was added protecting the Company from excessive load being shifted to the weekend period for these Schedule 6P customers.

The Commission concludes that the Company's proposal to make weekend energy charges on-peak for Schedule 6P should be rejected; however, it is appropriate for qualifying language to be added to Schedule 6P in order to ensure that excessive load is not shifted to this period. Further, the Company and the Public Staff should jointly develop such qualifying language to be submitted for Commission approval.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 70

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn recommended that for Schedules 5P, 6 and 6P a mid-day off-peak period should be adopted during the base (non-summer) months. Mr. McLawhorn recommended that the mid-day off-peak period should be from 1:00 to 5:00 p.m. Mondays through Fridays for the base months of October 1 through May 31. Mr. McLawhorn asserted that system demand during the mid-day period is significantly lower than at either the early morning or early evening peaks. He argued that there is the opportunity to shift load during the non-summer months, thereby avoiding or decreasing the need for costly generation. Although the Company does not maintain historical data on historical system incremental costs or system Lambda, Mr. McLawhorn expressed the belief that the Company's on-peak to off-peak variability would be similar to that of Duke and CP&L.

On rebuttal, Company witness Evans testified that the Company's non-residential customers do not exhibit the same load shape as the system. While the residential class and the overall system have a substantial mid-day valley in their load shapes, the general service customers do not. Mr. Evans testified that the non-residential customers do not have enough variation in their daily load shapes to transfer a significant portion of peak load to the proposed mid-day off-peak period. Witness Evans noted that the Company's generating system has been designed to accommodate daily fluctuations in load. The Bath County Pumped Storage Facility, with a peak capacity of 1,260 mW, can operate for as long as 10-12 hours per day. The off-peak pumping of these units, which utilizes excess generation, can require as much as 1,556 mW, depending on operational needs.

For purposes of this proceeding, the Commission is not persuaded that it should classify the mid-day non-summer period as off-peak for nonresidential customers. Mr. McLawhorn concedes that he has insufficient incremental cost and Lambda information to quantify cost differentials. He bases his on-peak, off-peak variability on comparisons to CP&L and Duke. However, these other utilities may not have the same type peaking capacity as the Company and may have less need to preserve off-peak valleys for recharging pumped storage facilities.

Nevertheless, the Commission concludes that the Company should prepare a study for presentation with its next rate case which explores the effect of adding mid-day off-peak hours during non-summer months for all nonresidential time-of-day rate schedules. The study should include estimates of the number of customers who might shift their load to the period in question under various scenarios, and the cost-effectiveness of such shifts.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 71 AND 72

The evidence for these findings of fact is found in the testimony of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn recommended that the Company should provide separate details on residential time- of-use (TOU) customers' monthly bills showing on-peak and off-peak kWh usage and savings over non-time-of-use rates. He also recommended implementation of a TOU comparative billing program for residential customers. Both of these recommendations were accepted by witness Evans; however, witness Evans expressed concerns about the costs related to the comparative billing program. He recommended that the program be limited to 200 volunteers at a time. The Commission concludes that both of the above-referenced programs should be implemented by the Company, and that the comparative billing program for non-time-of-use customers may be limited to 200 volunteers at a time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

The evidence for this finding of fact is contained in the testimony and exhibits of Company witness Evans and Public Staff witness Turner. Company witness Evans proposed that Schedule 1, Residential Service, contain the same multi-level blocked structure of charges for kWh sales during the billing months of October through May.

Witness Turner recommended a flat charge for all kWh during the base period (October through May) with a price differential between the base and summer periods. He explained that this change is appropriate for three reasons. First, customers understand and accept a flat charge better than a blocked rate. Second, the summer/winter differential will be spread evenly at all consumption levels during the base months. Third, this completes the flat rate design which was the Public Staff's goal when the 1500 kWh block design was proposed in Docket No. E-22, Sub 265. On cross examination, witness Evans accepted the Public Staff's recommendation.

The Commission concludes that the single block charge for all kWh sales during the months of October through May for customers on Schedule 1, Residential Service, as proposed by the Public Staff is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 74 AND 75

The evidence for these findings of fact is based on the testimony of Public Staff witness McLawhorn and Company witness Evans. Witness McLawhorn recommended that the Company's Residential Conservation Discount (RCD) of $0.00251/kWh be replaced with a 5.0% reduction on kWh charges for Schedules 1 and 1T and on kW and kWh charges for Schedule 1P. He testified that this change would restore the RCD to its original approved level. Witness Evans accepted this recommendation.

Witness McLawhorn also recommended that the Company's proposal to reference the publications containing the Energy Saver Home thermal efficiency standards in the residential rate schedules rather than include the standards within the rate schedules should be allowed only if the Company is required to maintain the current standards on file with the Commission and to obtain Commission approval before changing any of the standards. Witness Evans accepted this recommendation.

The Commission concludes that both of witness McLawhorn's recommendations concerning the Residential Conservation Discount and Energy Saver Home guidelines are reasonable and should be implemented in this case. The Commission further notes that the Company has filed a current copy of its publication entitled "Energy Saver Home - Thermal and Equipment Standards" on January 10, 1991, in Docket No. E-22, Sub 323, and has requested that the standards be approved effective with the rates approved in this rate case. The Commission will make its determination on the standards by separate Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 76

The evidence for this finding of fact is found in the testimony of Public Staff witness McLawhorn and Company witness Evans. Both witnesses agreed to the provision to include language requiring a minimum SEER level of 10.0 for installations of heat pumps and central air conditioners in new home construction; however, witness Evans opposed the inclusion of residences installing replacement units under this guideline. He asserted the difficulty of policing the replacement market.

The Commission agrees that the change recommended by Public Staff witness McLawhorn cannot be enforced by the Company where customers replace units in existing homes. As the new standard becomes mandatory, vendors likely will offer units that do not meet the new standard at a substantial discount. This practice will add pressure for customers to buy replacement units that fail to qualify.

The Commission deems it inadvisable to impose requirements that the Company cannot monitor and enforce. The Commission therefore concludes that the new efficiency standard will apply only to newly constructed residences after January 1, 1992.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 77

The evidence for this finding of fact is found in the testimony of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn recommended that the following guidelines be added to Schedule 1W outlining water heater specifications for participation in this schedule:

(1) Minimum 30-gallon tank size
(2) 240 volts
(3) Quick recovery
(4) Minimum 140° temperature setting
(5) Insulation wrap (optional, but strongly encouraged)

Witness Evans agreed with the recommendation. The Commission concludes it is reasonable that these specifications should be included in Schedule 1W.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 78 AND 79

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Evans and Doswell and Public Staff witness McLawhorn. The Company proposed, in its initial filing that Rider A/C Interruptible Air Conditioning Service, Residential Service be expanded to those areas of the Company's North Carolina service territory that have existing control equipment. The Company made no proposal with respect to the expansion of Rider J-Interruptible Electric Water Heating Service, Residential Service.

Public Staff witness McLawhorn indicated that Rider J and Rider A/C have been dispatched by the use of a "Ripple Control" system. The ripple control system is only available in the Company's more densely populated areas, but the Company is installing a newer, more efficient control system that utilizes a radio FM-sideband signal. The FM-sideband control is expected to be operational in 1991. The Public Staff suggests that the Commission require the Company to expand its Water Heater Load Control Program and Residential Air Conditioning Load Control Program throughout its service territory as quickly as practical.

Company witness Doswell offered a detailed cost/benefit analysis of the residential water heater and air conditioning load control programs. The results of the cost/benefit analysis indicate that continued promotion and expansion on a system-wide basis of the Residential Water Heater Load Control Program would increase the cost to customers by $150 million over time. The analysis also evidenced a net cost of the program if the customer credit was reduced to zero dollars. Mrs. Doswell's testimony indicates that the Water Heater Load Control Program is more effective in the winter season than in the summer season but that the Company forecasts the summer season to be its critical season for planning capacity additions. Accordingly, a demand-side program such as Water Heater Load Control, which is more effective at reducing winter peak, is less valuable than a demand-side program which offers similar reductions to summer peak demand.

The cost/benefit analysis of the system's expansion of the Air Conditioning Load Control Program indicates that the program increases system costs to customers by $71 million over time. However, the Company is continuing to study both cycle control and block control technologies in an effort to develop an appropriately priced air conditioning control program. Mrs. Doswell recommended that both Rider J and Rider A/C be continued at their current levels and that the programs not be actively promoted until further analysis indicates otherwise.

The Commission is dedicated to the promotion of cost effective demand-side programs and strongly encourages the Company to continue its analysis of these and other programs. However, the Commission believes that the expansion of those programs at this time is not necessarily cost justified. Accordingly, the Company's proposal to continue those programs at their current levels and without active promotion is appropriate.

Nevertheless, the Commission concludes that the Company should make regular progress reports to the Commission of its efforts to replace the current ripple control with radio control, and of its findings regarding alternative combinations of rate discounts versus interruption times for the air conditioning load control program. The progress reports should be filed with the Company's short-term action plans filed pursuant to NCUC Rule R8-59.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80 AND 81

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness McLawhorn. Witness McLawhorn proposed adding clarifying language to Rider A/C describing the operation of the Company's air conditioning load control program. He testified that the language should state that it is a cycling program which cycles the appliance on for 18 minutes and off for 12 minutes during each 30 minutes of a control period and that a control period normally lasts no more than four hours per day except during system capacity shortages. Witness Evans accepted this recommendation.

Witness McLawhorn further testified that Rider J and Rider A/C should be merged into one residential load control rider for the purpose of improving focus and marketability of the two programs. Witness Evans also accepted this recommendation.

The Commission concludes that both the change to clarify operation of the air conditioning load control program and to merge Rider J and Rider A/C into one rider are reasonable and appropriate and should be implemented in this case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 82

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Evans and Public Staff witness Turner. Underground Line Extension Plan F, as filed with the Commission, states the conditions under which the Company will provide underground service to customers and the determination of any contribution in aid of construction. Witness Turner addresses the specific condition set forth by the plan in Residential section II, paragraph A, item 4, and paragraph B, item 4, which generally states that underground service will be provided at no cost if the average service lateral length does not exceed

200 feet, and no service lateral exceeds 250 feet. The Company has interpreted this to mean that customers with service laterals greater than 200 feet are required to pay the full cost differential between overhead and underground service for the entire length of the service including the first 200 feet. Witness Turner stated that it is his belief that this interpretation unfairly charges customers requesting service laterals greater than 200 feet. Also, this interpretation is inconsistent with similar plans in effect for both Carolina Power & Light Company and Duke Power Company. He recommended that the plan be changed to charge customers for only the cost difference beyond the first 200 feet. He proposed the addition of a new paragraph I.J. to read as follows:

> Residential customers requesting secondary service laterals greater than 200 feet shall be charged an amount equal to the cost difference expressed in dollars per foot times the difference between the length of the service lateral minus 200 feet with no service lateral exceeding 250 feet.

In his rebuttal testimony witness Evans agreed with the Public Staff's recommendation as it applies to new individual residences under Section II.B. However, he did not agree to the recommendation as it applied to new subdivisions under Section II.A.

Witness Evans contended that Mr. Turner had approached Section II.A. as though it calls for a separate charge for a single service lateral. Section II.A., however, addresses subdivisions as a whole. Under the subdivision section of Plan F, if a subdivision meets all the criteria of Section II.A., underground service is provided to the entire subdivision at no charge. If one of the criteria is not satisfied, however, service to the entire subdivision is provided in accordance with the cost difference. The cost difference in such instances applies to primary service, secondary service and service laterals.

Mr. Evans testified that additions to the Company's distribution rate base have increased dramatically in the last few years. Mr. Evans stated that Plan F was responsible for a large portion of that increase because it eliminated much of the contribution required under the previous plan. Mr. Evans testified that the Company was developing a new line extension plan that would again require advance contributions.

The Commission concludes that the recommendation of the Public Staff regarding Section II.B. of Plan F should be adopted. The Commission further concludes that it should not modify the language of Paragraph II. A. of Plan F. This paragraph is not applied in any case where only service laterals greater than 200 feet in length are involved. The paragraph is applied to all the elements of service for the entire subdivision. The criteria for service laterals should not be singled out for a change at this time. Additionally, the Company has represented that it will file an entirely new line extension plan in the near future. It is unwise to order this change in the plan with a major change being proposed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 83

The evidence for this finding of fact is found in the testimony and exhibits of Public Staff witness Turner and Company witness Evans. It is the policy and practice of the Company to assign the unpaid amount of a nonresidential account to the person of the same name holding a residential account (in cases where the nonresidential account is in the name of an individual). Although the unpaid nonresidential account is assigned to a residential account in such circumstances, the Company will not terminate service to the residential customer because of this unpaid balance. If the nonresidential account is held by a partnership or corporation, the unpaid amount is not assigned to a residential account.

Witness Turner contended that this policy is discriminatory in that the assignment only takes place when the nonresidential account is in the name of an individual. He stated that the same collection policy should be pursued for all nonresidential customers. He recommended that the Commission direct the Company to cease this practice in its North Carolina retail jurisdiction. Witness Evans accepted the recommendation.

The Commission concludes that the Company's collection policy should be consistent for all nonresidential customers and that delinquent commercial payments should not be assigned to the customer's residential account.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 84

The evidence supporting this finding of fact is found in the testimony and exhibits of CIGFUR witness Phillips and Company witness Evans. Witness Phillips recommends that the Company be required to offer large general service rates containing energy charges that are blocked for size and load factor unless Rate Schedule 6P is designed to accomplish the same objective. Mr. Phillips notes that Duke and CP&L have blocked industrial service energy charges in North Carolina. Witness Phillips testified that the Company's proposed energy charge for Schedule 6P is more appropriate than its proposed energy charge for Schedule 6, but should be priced lower for high load factor customers.

On rebuttal, Company witness Evans testified that Rate Schedule 6 does contain energy charge blocking such that only customers with load factors in excess of 29% can receive the lower energy charges in the rate schedule. Mr. Evans testified that Rate Schedule 6 also has a feature to recognize large loads normally associated with industrial customers for power supply demand charges. For customers with demands in excess of 1,000 kW, under the Company's proposed changes for Rate Schedule 6, only their on-peak demands are used to determine power supply billing demands. The Company also proposes to institute a distribution demand charge that would recover the annual distribution costs associated with the billing demand.

Mr. Evans compared the Company's proposed North Carolina Schedule 6P and the proposed Virginia industrial rates. Mr. Evans noted that different cost allocation methods are used in the two jurisdictions and that this difference results in differences in rates. He also noted that the energy charges for the North Carolina Rate Schedule 6P are based on marginal energy costs and not the average embedded costs used for the design of the new proposed general service rates in Virginia. Mr. Evans testified that the long term goal for the new proposed general service rates in Virginia is to price the energy charges at on-peak and off-peak marginal costs. Thus, in the future it is expected that the energy charges for the Virginia general service rates will rise and become more in line with the energy charges for North Carolina Rate Schedule 6P.

The Commission has carefully examined the evidence on this issue and determines that it must reject CIGFUR's proposal to further modify Rate Schedules 6 and 6P. The Commission concludes for purposes of this proceeding that Schedules 6 and 6P have sufficient features beneficial to large users and those with high load factors.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 85

The evidence supporting this finding of fact is contained in the testimony of public witnesses Rex Carter, John Moulton, Public Staff witness Turner and Company witness Evans. Several of the Company's cotton gin customers appeared at the hearing and expressed their concern about the level of the proposed rates that these customers will be required to pay under the Company's proposals. The customers take exception to the existing and proposed off-peak hours because of the inconvenience to their businesses of operating during those hours. The customers also take exception to the distribution demand feature of the schedule and the associated ratchet provisions. The customers also take issue with the power supply demand charge.

Company witness Evans testified that the schedule is underpriced and will continue to be underpriced after approval of the recommended changes. Mr. Evans testified that the power supply demand charge is intended to recover the production and transmission costs and will be applied to the customer's monthly maximum on-peak demand.

Mr. Evans testified that the distribution demand charge is intended to recover the distribution plant invested to provide service to the customers. Distribution plant is sized to serve the customers' maximum load whenever it occurs. The distribution demand charge is based on the customer's maximum demand during the on-peak or off-peak period. The billing demand for the distribution demand charge for any month is the higher of (1) the maximum demand for the month in question or (2) the maximum demand established during the preceding eleven billing months. The reasoning for this approach is that there is an annual cost associated with the local distribution equipment necessary to serve the customer.

Public Staff witness Turner testified that an analysis should be made of the load pattern requirement and energy use of the cotton gin customers to determine whether they are sufficiently unique in comparison to the load characteristics of the customer class as a whole to justify a separate rate schedule for the customers. Mr. Turner testified that cotton gins are not the only seasonal-type customers. Mr. Turner noted the problem of trying to design a rate for every specific type customer. Mr. Turner stated that it is necessary to keep customers in groups as long as their patterns are consistent with each other.

The Company filed a late exhibit following the hearing which modified the on-peak hours in Schedule 5P in order to give some relief to cotton gin operators. The Commission is of the opinion that the modified on-peak hours proposed for Schedule 5P should be approved.

However, a major complaint from the cotton gin operators regarding Schedule 5P is the ratchet feature contained in the distribution demand charge. The demand ratchet imposes a demand charge every month whether or not any electricity is used for up to twelve months. The demand ratchet is a peak load pricing device popular for use in non-time-of-use rate schedules. The Commission has for some years viewed demand ratchets as being redundant in time-of-use rate schedules, and it has considered time-of-use metering and pricing to be far more efficient peak load pricing mechanisms than demand ratchets. Therefore, the Commission concludes that the demand ratchet feature of the distribution demand charge contained in time-of-use Rate Schedule 5P should not be allowed.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 86

The evidence supporting this finding of fact is found in the testimony of Lester Teal, Controller of the North Carolina Department of Transportation. Witness Teal requested that the Commission require the Company, for consideration in its next rate case, to conduct a study to determine whether it is appropriate to develop a separate rate schedule for traffic signals. The Department of Transportation presently is billed under Rate Schedule 30. No party objected to the study requested by witness Teal. The Commission therefore concludes that it should direct the Company to undertake a study of traffic signal rates for presentation with its next rate case in order to determine whether a separate traffic signal rate schedule is appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 87

In addition to the revisions discussed in the above findings of fact the Company proposes various miscellaneous rate changes, administrative changes, and clarifications on its rate schedules and in its terms and conditions for service which are unopposed by any party.

The Commission concludes that the rate designs, rate schedules, and terms and conditions for service as proposed by the Company are appropriate and should be adopted, except as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 88

The evidence supporting this finding of fact is contained in the record in this case. G.S. 62-133.2 provides that the Commission shall hold a hearing within 12 months after an electric utility's last general rate case order to determine whether an increment or decrement rider is required "...to reflect actual changes in the cost of fuel and the fuel cost component of purchased power over or under base rates established in the last preceding general rate case." G.S. 62-133.2 further provides that additional hearings shall be held on an annual basis but only one hearing for each such electric utility may be held within 12 months of the last general rate case. G.S. 62-133.2(c) sets out the verified, annualized information and data which the utility is required to furnish to the Commission at the hearing for a historic 12-month period "...in such form and detail as the Commission may require..." Pursuant to Rule R-55, the Commission has prescribed the 12-month period ending June 30, 1990, as the test period for the fuel proceeding. The Company had indicated in its May 31, 1990, Application for a General Increase in Rates (Docket No. E-22, Sub 314) that it intended to update its calculations of fuel cost and the fuel component of purchased power associated with that general rate case for the 12-month period ended June 30, 1990, consistent with the Company's annual fuel clause test period. On July 16, 1990, North Carolina Power filed a Motion for Consolidation of Hearings in which it moved to consolidate hearings in its general rate case and its fuel clause proceeding, Docket No. E-22, Subs 314 and 319, which motion was granted by the Commission in its August 2, 1990, order. The Commission concludes that the appropriate test period for the base fuel factor determination is the 12-month period ending June 30, 1990.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 89-91

The evidence for these findings of fact is found in the testimony of Company witnesses Zimmerman and Evans and Public Staff witnesses Lam and Turner.

Company witnesses Zimmerman and Evans and Public Staff witness Lam testified with regard to the July 1, 1989, to June 30, 1990, test period sales, generation, and nuclear capacity factor. Company witnesses Zimmerman and Evans testified that the July 1, 1989, to June 30, 1990, test period levels of sales and generation were 55,560,803 mWh and 59,233,302 mWh, respectively. Public Staff witness Lam accepted these levels of sales and generation for use in his fuel computation. The generation is broken down by type as follows:

	mWh
Coal	23,163,688
IC	260,450
Heavy Oil	1,279,127
Gas	88,579
Nuclear	25,491,351
Hydro	2,939,828
Pumped Storage	(2,303,016)
Photovoltaic	44
Purchase & Interchange	
NUG & Non-fuel	8,960,925
Other	7,213,993
Delivered	(7,861,667)
Total	59,233,302

Company witness Zimmerman testified that the Company achieved a system nuclear capacity factor of 85.9% for the July 1, 1989, to June 30, 1990, test period. Mr. Zimmerman normalized the system nuclear capacity factor to a level of 65.6%, which is the latest North American Electric Reliability Council's (NERC) 5-year nuclear capacity factor. Mr. Lam agreed that the nuclear capacity factor of 85.9% as achieved by the Company was abnormally high and should be normalized to the latest NERC 5-year PWR average of 65.6%. No other party offered testimony on the normalized nuclear capacity factor. In the absence of evidence presented to the contrary, the Commission concludes that the July 1, 1989, to June 30, 1990, test period levels of sales and generation are reasonable and appropriate for use in this proceeding. The Commission further concludes that the 65.6% normalized system nuclear capacity factor is reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 92

The evidence for this finding of fact is found in the testimony of Company witness Zimmerman and Public Staff witness Lam.

Company witness Zimmerman and Public Staff witness Lam testified regarding normalized generation. Mr. Zimmermann's prefiled testimony normalized generation using a historical level of generation based on 12-months ended December 1988. Mr. Lam's prefiled testimony normalized generation based on the 12-month test period ended June 30, 1990, as mandated by the Commission for the fuel adjustment case, Docket No. E-22, Sub 319. Mr. Zimmermann on direct testimony subsequently adopted Mr. Lam's position that the normalized generation be based on the 12-month test period ended June 30, 1990. There was no other testimony on this subject.

The Commission concludes that normalized generation be based on the 12-month test period ended June 30, 1990.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 93

The evidence for this finding of fact is found in the testimony of Company witness Evans and the testimony of Public Staff witness Turner.

Witness Evans testified that consistent with Commission Rule R8-55(d)(2) the Company's system sales data for the 12-month period ending June 30, 1990, was adjusted by jurisdiction for weather normalization, customer growth, and increased usage. Witness Evans adjusted total company retail sales by 2,130,694 mWh. The adjustment is the sum of adjustments for weather normalization, customer growth, and increased usage of 892,630 mWh, 598,529 mWh, and 639,535 mWh, respectively.

Witness Turner presented an adjustment to per book kWh sales for the twelve-month period ending June 30, 1990, due to weather normalization, customer growth, and increased usage of 892,630 mWh, 544,841 mWh, and 634,379 mWh, respectively. The normal weather adjustment provided by the Company was reviewed and accepted by the Public Staff.

The growth adjustment provided by witness Turner was calculated by multiplying the monthly change in customers by average kWh per bill and summing the result over the 12-month test period where the change in customers is the difference between the end-of-period value and actual customers. Increased usage was calculated by multiplying the difference between test year average usage and the average usage of the preceding year by one-half the end-of-period level of customers.

As stated by witness Turner, the end-of-period level for each rate schedule is computed by using an equation based on a trended analysis or regression of actual billings for a 36-month period ending July 1990. In most cases the equation selected as representative of customer growth was either a polynomial or an exponential. The basis for curve selection was an equation based on the most recent 36-months of actual data which best fit the data as determined by the value of its R-square. Witness Turner's adjustments for customer growth and increased usage were reviewed and accepted by the Company.

Based on the foregoing evidence, the Commission concludes that the adjustment for a weather normalization of 892,630 mWh for the Company's total retail sales as filed by the Company, reviewed and accepted by the Public Staff is reasonable and appropriate for use in this proceeding. The Commission also concludes that the adjustments due to customer growth and increased usage for the total company retail of 544,841 mWh, and 634,379 mWh, respectively, as presented by the Public Staff and reviewed and accepted by the Company, are reasonable and appropriate adjustments for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 94

The evidence for this finding of fact is found in the testimony of Company witnesses Zimmerman and Evans and Public Staff witnesses Lam and Turner.

The testimonies of Company witness Evans and Public Staff witness Lam address the adjusted level of generation. Witness Evans presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1990, due to weather normalization, customer growth, and increased usage of 2,256,339 mWh, to arrive at Mr. Zimmerman's adjusted generation level of 61,489,642 mWh.

Witness Turner presented an adjustment to per book mWh generation for the 12-month period ended June 30, 1990, due to weather normalization, customer growth, and increased usage of 2,194,025 mWh, to arrive at Mr. Lam's adjusted generation level of 61,426,814 mWh.

Witness Turner's adjustments to generation were accepted by witness Evans. Subsequently, witness Zimmerman accepted witness Lam's adjusted fuel generation level of 61,426,814 mWh and the breakdown of that generation by type as follows:

	mWh
Coal	27,828,435
IC	312,920
Heavy Oil	1,536,744
Gas	106,407
Nuclear	19,434,866
Hydro	2,939,828
Pumped Storage	(2,303,016)
Photovoltaic	44
Purchase & Interchange	
NUG & Non-fuel	10,765,477
Other	8,666,776
Delivered	(7,861,667)
Total	61,426,814

Based on the foregoing evidence and with no other evidence to the contrary, the Commission concludes that the adjustment of 2,194,025 mWh is reasonable and appropriate for use in this proceeding, and that the resultant adjusted fuel generation level of 61,426,814 mWh broken down as noted above is also reasonable and appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 95-97

The evidence for these findings of fact is found in the testimony and exhibits of Company witness Zimmerman and Public Staff witness Lam.

Witness Zimmerman's prefiled testimony of September 21, 1990, contained fuel prices as follows: (1) coal price of $15.20/mWh; (2) internal combustion turbine price of $30.55/mWh; (3) heavy oil price of $34.88/mWh; (4) gas price of $49.62/mWh; (5) nuclear fuel price of $5.19/mWh, including interim nuclear fuel storage expenses; (6) other purchased and interchanged power price of $13.26/mWh; (7) delivered purchased and interchanged power price of $1.99/mWh; and (8) hydro, pumped storage, photovoltaic, and non-utility generation and non-fuel generation at a zero fuel price.

Mr. Lam, in his testimony, accepted Mr. Zimmerman's fuel prices for other purchased and interchanged power ($13.26/mWh), delivered purchased and interchanged power ($1.99/mWh), and hydro, pumped storage, photovoltaic, NUG and non-fuel generation (zero fuel price), but rejected the fuel prices for the other types of generation. Mr. Lam recommended fuel prices as follows: (1) coal price of $14.90/mWh; (2) IC turbine price of $20.01/mWh; (3) heavy oil price of $33.38/mWh; (4) gas price of $69.21/mWh; and (5) nuclear fuel price of $4.76/mWh, excluding all interim nuclear fuel storage expenses.

Mr. Zimmerman, upon review, accepted all of the fuel prices recommended by Mr. Lam, including exclusion of all interim nuclear fuel storage expenses from the nuclear fuel calculation. In the absence of any evidence to the contrary, the Commission concludes that the Company fuel prices accepted by the Public Staff and fuel prices recommended by the Public Staff and accepted by the Company, excluding all interim nuclear fuel storage expenses, are reasonable and appropriate for use in this proceeding.

Accordingly, the fuel calculation incorporating the conclusions reached herein is shown in the following table:

	Adjusted Generation (mWh)	Fuel Price $/mWH	Fuel Dollars ($000s)
Coal	27,828,435	14.90	414,644
IC	312,920	20.01	6,262
Heavy Oil	1,536,744	33.38	51,297
Gas	106,407	69.21	7,364
Nuclear	19,434,866	4.76	92,510
Hydro	2,939,828	-	-
Pumped Storage	(2,303,016)	-	-
Photovoltaic	44	-	-
Purchase & Interchange			
NUG & Non-Fuel	10,765,477	-	-
Other	8,666,776	13.26	114,921
Delivered	(7,861,667)	1.99	(15,645)
TOTAL	61,426,814		671,353
System Sales and Fuel Cost (mWh)	57,632,653		671,353
Base Fuel Factor (¢/kWh)			1.165

The Commission concludes that adjusted fuel test period expenses of $671,353,000 and the base fuel factor of 1.165¢/kWh without gross receipts tax (1.204¢/kWh with gross receipts tax), is reasonable and appropriate for use in this proceeding. This approved base fuel factor is .021¢/kWh lower than the current level in effect of 1.225¢/kWh, including gross receipts tax (this consists of the current base fuel factor of 1.592¢/kWh and the current fuel adjustment decrement from fuel adjustment proceeding Docket No. E-22, Sub 308 of .367¢/kWh, all including gross receipts tax). Such change will result in a decrease in fuel revenues of $520,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 98

The evidence supporting this Finding of Fact is found in the testimony and exhibits of Company witness Bolton and Public Staff witness Maness and in Docket No. M-100, Sub 113.

In its original filing, the Company proposed to refund excess deferred income taxes through a rider that would provide a 12-month credit to customer bills. In rebuttal testimony, Mr. Bolton proposed a lump-sum refund plan. The Public Staff, in its proposed order, agreed with the concept of a lump-sum refund plan. Therefore, the Commission finds that a lump-sum refund of the excess deferred income taxes is appropriate.

The Public Staff and the Company presented different amounts for this refund. The Public Staff recommended that the North Anna Unit 4 loss amortization be recovered as an offset to the refund of excess deferred income taxes. The Commission has already concluded that the Public Staff transfer of the North Anna Unit 4 amortization from operating revenue deductions to a refund offset is appropriate, as discussed in the Evidence and Conclusions for Findings of Fact Nos. 38-55. However, such offset should be reduced to reflect the continued recovery by the Company of such amortization up to the date the rates set in this proceeding become effective.

Company witness Bolton presented a schedule on rebuttal setting forth the calculation of the excess deferred tax refund amount as of December 31, 1990. The Commission concludes that the Company amount of $6,100,000 should be reduced by the revenue effect of the North Anna Unit 4 offset as described above. The Commission also concludes that the amount of the refund should be further adjusted to reflect the following items:

1. The continuing overrecovery by the Company of protected excess deferred income taxes up to the date the rates set in this proceeding become effective.

2. Interest, calculated at 10% per annum, from January 1, 1991, to the date refunds are made to customers.

IT IS THEREFORE, ORDERED as follows:

1. That North Carolina Power Company shall be, and hereby is, authorized to adjust its electric rates and charges effective with the date of this Order, so as to produce an increase in gross annual revenue, excluding fuel revenue,

from its North Carolina retail operations of $13,916,000 based upon the adjusted test year level of operations.

2. That the Company shall replace the current base fuel factor of 1.592¢/kWh, including gross receipts tax, approved in general rate case Docket No. E-22, Sub 273, with the new base fuel factor of 1.204¢/kWh, including gross receipts tax approved in this proceeding.

3. That within five working days after the date of this Order, North Carolina Power shall file with the Commission five copies of its rate schedules and service regulations designed to produce the increase in revenues adopted herein in accordance with the rate design guidelines attached hereto as Appendix A. The rate schedules required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule.

4. That North Carolina Power shall prepare cost allocation studies for presentation with its next general rate case which allocate production plant based on the following methodologies:

(a) Summer/winter peak and average
(b) Summer/winter coincident peak
(c) Average and excess

The studies shall be included in item 45 of Form E-1 of the minimum filing requirements for a general rate application.

5. That the Company shall, within ten working days after the date of this Order, and following consultation with the Public Staff, file a refund plan detailing the procedure it will follow in determining the excess deferred tax refund and the method of determining each customer's share of the refund. Such plan shall include, but is not necessarily limited to, the following: (1) method of determining specific customer refund amount; (2) determination of refund amount and related interest; (3) method of determining refund factor in dollars per kWh; (4) the month in which refunds will be made; (5) final statement following refund providing verified refund and disposition of unrefunded amount; and (6) minimum check cut-off amount.

6. That within ten working days after the date of this Order, the Company shall file with the Commission five copies of computations showing the overall North Carolina retail rate of return and the rates of return for each rate schedule which will be produced by the revenues approved by this Order. Such computations shall be based on the cost allocation methodology approved herein.

7. That the Company shall give appropriate notice of the rate increase approved herein by mailing a notice to each of its North Carolina retail customers during the next normal billing cycle following the filing and approval of the rate schedules described in Decretal Paragraph No. 3 above. The Company shall submit its proposed customer notice to the Commission for approval prior to the notice being mailed out to the customers.

8. That all time-of-use rates shall be designed to be revenue neutral with corresponding non-time-of-use rate schedules.

9. That the following holidays shall be classified as off-peak periods for Schedules 1P, 1T, 5P, and 6P: New Year's Day, Good Friday, Memorial Day, July 4, Labor Day, Thanksgiving (Thursday and Friday), and Christmas Day.

10. That North Carolina Power shall prepare a study of other holidays not currently classified as off-peak periods in order to determine if they are predominately off-peak, and that the study shall be presented to the Commission with the Company's next general rate application.

11. That weekends shall continue to be classified as off-peak for energy charges in Schedule 6P. Language to protect the system from excessive load shifting during this period may be developed jointly by the Company and the Public Staff.

12. That North Carolina Power shall prepare a study of the mid-day hours of nonsummer months in order to determine what effect such hours would have on the nonresidential time-of-use rate schedules if the hours were classified as off-peak. The study shall be presented to the Commission with the Company's next general rate application.

13. That the Company shall provide separate details on residential time-of-use monthly bills showing on-peak and off-peak kWh usage and savings over non-time-of-use rates.

14. That the Company shall offer a time-of-use comparative billing program to its residential customers, and that such program may be limited to 200 volunteers at a time.

15. That the Company shall revise residential Schedule 1 to replace the multiple level kWh charges during the base period of October through May with a flat kWh charge.

16. That the Company shall replace its current residential conservation discount decrement of $0.00251/kWh with a 5.0% reduction to kWh charges for Schedules 1 and 1T and to kW and kWh charges for Schedule 1P.

17. That the Company shall maintain on file with the Commission a copy of its thermal efficiency standards for Energy Saver Homes, and shall obtain Commission approval prior to making any change in the standards.

18. That the Company shall include a statement under the energy conservation standards section of Schedules 1, 1P, and 1T stating that any heat pump or central air conditioner installed in newly constructed residences on or after January 1, 1991, must have a minimum Seasonal Energy Efficiency Ratio (SEER) of 10.0 in order to qualify for the Energy Saver Home program.

19. That the Company shall include language in Schedule 1W stating that the water heater specifications for participation in Schedule 1W are as follows:

(1) Minimum 30-gallon tank size
(2) 240 volts
(3) Quick recovery
(4) Minimum 140° temperature setting
(5) Insulation wrap (optional, but strongly encouraged)

20. That the Company shall add clarifying language to Rider AC stating that the air conditioner load control program is a cycling program which cycles the appliance on for 18 minutes and off for 12 minutes during each 30 minutes of a control period, and that a control period normally lasts no more than four hours per day except during system capacity shortages.

21. That the Company shall merge Riders J and A/C into one Residential Load Control Rider.

22. That the Company shall file with the Commission a revised Underground Line Extension Plan F which provides that individual customers under Section II.B of the Plan shall be charged only for that portion of the applicable cost of service laterals exceeding 200 feet.

23. That the Company shall discontinue its policy of assigning the unpaid amount of nonresidential accounts to the person of the same name holding a residential account unless the person agrees to such assignment in writing.

24. That the Company shall delete from the distribution demand charge in Schedule 5P and from any time-of-use rate schedule the demand ratchet feature proposed herein.

25. That the Company shall study the feasibility of a separate traffic signal rate schedule, and shall present the study to the Commission with its next general rate application.

26. That the Company shall make regular progress reports to the Commission regarding its efforts to replace the current ripple control with radio control in its residential load control programs, and the Company's findings regarding alternative combinations of rate discounts versus interruption times for the air conditioning load control program. The progress reports shall be filed with the Company's short-term action plans submitted pursuant to NCUC Rule R8-59.

ISSUED BY ORDER OF THE COMMISSION.
This the 14th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

Commissioner Cook dissenting in part.
Commissioner Cobb dissenting in part.

APPENDIX A

NORTH CAROLINA POWER
DOCKET NO. E-22, SUB 314

Guidelines for Design of Rate Schedules

(A) Hold the extra charges and miscellaneous service charges at the same levels proposed by the Company.

(B) Distribute the overall revenue increase approved herein in such a way as to produce customer class rates of return having approximately the following percent return indices:

	% return index
Residential	0.905
Small General Service	1.105
Large General Service	1.085
Lighting	1.150
Overall	1.000

(C) Maintain revenue neutrality between comparable time-of-use rate schedules and non-time-of-use rate schedules.

COMMISSIONER RUTH E. COOK, DISSENTING IN PART. I agree with all of the substantive findings and conclusions set forth in the Commission's Order. However, I wish to take issue with one decision made by the Majority; that being the decision to strike from the record and deny consideration of the three responses that North Carolina Power, the Public Staff, and the Attorney General filed following the proposed orders.

The Commission often provides for reply comments so that parties can either address alleged misstatements in other parties' comments or provide further legal argument prompted by other parties' comments. I believe that there is a great deal to be gained from this exchange whether the Commission orders it or, as here, the parties do it on their own initiative. Wisdom does not reside with the Commission alone.

I cannot support any decision which denies parties from presenting their views to the Commission, and I therefore dissent on this limited point.

Ruth E. Cook, Commissioner

COBB, COMMISSIONER, DISSENTING. I dissent from Finding of Fact 44 which excludes 50% of the North Carolina portion of the compensation paid to three of the Company's executive officers. This amounts to a total of $14,000.

The exclusion of this compensation is predicated upon a theory that half of the efforts of these officers are dedicated "to meeting the demands of the common shareholder." There is no contention that the compensation itself is excessive or that the allocations are inappropriate.

Even if we disregard the arbitrary standard applied by the Commission and the obvious fact that the great majority of the duties performed by these officers benefit both the ratepayers and the shareholders through the efficient operation of the Company, the Commission lacks legal authority to deny the recovery of all of the compensation paid. There can be no dispute that the compensation paid is a part of the Company's reasonable operation expenses recoverable under G.S. 62-133.

If it were to be determined that there is some legal basis for a partial disallowance of this compensation, it could be argued that the Commission has not gone far enough in its decision. Following the logic of this opinion, we should disallow 9.54% of <u>all</u> compensation paid since this is the estimated return on average common equity which benefits only the shareholder.

Historically, the disallowance of a portion of executive compensation was instituted by the Commission on its own motion to punish a public utility for granting substantial salary increases to its executives at the same time it was seeking substantial rate increases. It has been confirmed in subsequent rate cases both to show consistency on the part of the Commission and to allow the Commissioners to advise irate customers that the shareholders are being required to pay half the salaries of the "fat cat" officers (albeit there is no contention that these salaries are excessive).

It probably would be difficult to placate an unhappy customer of North Carolina Power by showing a disallowance of $14,000 while approving revenue increases of $13,916,000. However, I would concede that the approach of the majority might be the politic thing to do. Unfortunately, I am of the opinion that we totally lack legal authority to require such disallowances.

Laurence A. Cobb, Commissioner

DOCKET NO. E-22, SUB 329

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

In the Matter of Application of North Carolina Power Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	)	ORDER APPROVING FUEL CHARGE ADJUSTMENT

HEARD: Tuesday, November 19, 1991, at 9:30 a.m., in the Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Charles H. Hughes, Presiding; and Commissioners Laurence A. Cobb and Robert O. Wells

APPEARANCES:

For North Carolina Power:

James S. Copenhaver, Senior Regulatory Counsel, North Carolina Power, Post Office Box 26666, Richmond, Virginia 23261

For the Public Staff:

A. W. Turner, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

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. The statute further requires that additional hearings be held on an annual basis, but only one hearing for each utility may be held within 12 months of 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 under-recovery of reasonable fuel expenses prudently incurred during the test year. The last general rate case Order for North Carolina Power (or "the Company") was issued by the Commission on February 14, 1991 in Docket No. E-22, Sub 314. The Commission also issued a clarifying Order in that docket on April 12, 1991. The last Order approving a fuel charge adjustment for the Company was issued on December 20, 1990, in Docket No. E-22, Sub 319.

North Carolina Power filed testimony and exhibits in accordance with NCUC Rule R8-55 and G.S. 62-133.2 on September 13, 1991. North Carolina Power filed testimony and exhibits for the following witnesses: Charles R. Goode, III - Director, Regulatory Accounting; Daniel J. Green - Director, Planning Services; and Andrew J. Evans - Director, Rate Design. The Company also filed information and workpapers required by NCUC Rule R8-55(d).

On September 20, 1991, the Commission issued an Order scheduling a hearing, requiring a public notice and providing for the filing of interventions and testimony. The hearing was rescheduled by Order dated September 23, 1991.

On September 20, 1991, the Carolina Industrial Group for Fair Utility Rates (CIGFUR - I) filed a Petition to Intervene. The intervention of CIGFUR-I was allowed by Order dated September 25, 1991. On October 17, 1991, the Carolina

Utility Customers Association, Inc. (CUCA) filed a Petition to Intervene. The intervention of CUCA was granted by Order dated October 21, 1991.

On October 28, 1991, the Company filed the revised direct testimony and exhibits of Andrew J. Evans and the supplemental direct testimony of Daniel J. Green.

On October 28, 1991, the Public Staff filed the affidavit of Thomas S. Lam, an Engineer with the Electric Division. The filing included a notice that Mr. Lam's affidavit would be used in evidence at the hearing and that the witness would not appear or be subject to cross-examination unless an opposing party demanded the right of cross-examination pursuant to G.S. 62-68.

On October 30, 1991, the Company filed affidavits of each of its witnesses and a Notice that these affidavits would be used in evidence at the hearing and that the witnesses would not appear or be subject to cross-examination unless an opposing party demanded the right of cross-examination pursuant to G.S. 62-68.

The matter came on for hearing as scheduled on Tuesday, November 19, 1991. The prefiled testimony of all witnesses was copied into the record and their exhibits were admitted into evidence. The parties waived cross-examination of Company witnesses Goode, Green and Evans as well as Public Staff witness Lam.

Based upon the foregoing and the entire record, the Commission makes the following

FINDINGS OF FACT

1. 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. The Company has its principal offices and place of business in Richmond, Virginia.

2. The test period for purposes of this proceeding is the twelve months ended June 30, 1991.

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

4. The Company's actual test period jurisdictional fuel expense was $28,990,618. Actual jurisdictional fuel revenues were $29,024,394 and exceeded fuel expenses for the test period by $33,776. The Company's actual test period jurisdictional sales were 2,462,945 MWh.

5. The Company's adjusted jurisdictional test year retail sales of 2,511,293 MWh results from an additional 6,934 MWh of customer growth, 12,627 MWh of increased usage and an additional 28,787 MWh associated with weather normalization. These adjustments to normalize for weather and customer growth and usage are reasonable and appropriate for purposes of adjusting test period jurisdictional retail sales in this proceeding.

6. The Company's adjusted test period system fuel expenses result from an adjustment of ($39,562) to expenses associated with the normalization of its system nuclear capacity factor based upon the five-year (1986-1990) average capacity factor of 66.69% as published by the North American Electric Reliability Council (NERC) and further adjusted using September 1991 coal prices. The Company experienced an actual systemwide nuclear capacity factor of 69.3% during the test year. These adjustments to normalize for the five-year NERC nuclear capacity factor and updated coal related fuel prices are reasonable and appropriate for purposes of adjusting test period jurisdictional fuel expenses in this proceeding.

7. The Company's primary fuel cost component is based on the Company's normalized system fuel expenses and sales during the test year and is an increment of .001¢/kWh (excluding gross receipts tax) to the 1.165¢/kWh base fuel component approved in its last general rate case, Docket No. E-22, Sub 314.

8. Interest expenses associated with the over-collection of test period fuel revenues amounts to $5,066.

9. The Company's experience modification factor (EMF) is a decrement of .002¢/kWh (excluding gross receipts tax) associated with over-collected fuel revenues and interest on the over-collection.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

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

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

G.S. 62-133.2(c) sets out the verified, annualized information which each electric utility is required to furnish to the Commission in an actual fuel charge adjustment proceeding for a historical 12-month test period. In NCUC Rule R8-55(b), the Commission has prescribed the 12 months ending June 30, 1991, as the test period for North Carolina Power. The Company's filing on September 13, 1991, was based on the 12 months ended June 30, 1991.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

NCUC Rule R8-52(b) requires each utility to file a Fuel Procurement Practices Report at least once every ten years, plus each time the utility's fuel procurement practices change. Procedures related to North Carolina Power's procurement of fossil and nuclear fuels were filed in Docket No. E-100, Sub 47, on June 29, 1984, and revised on June 6, 1985. In addition, the Company files monthly reports of its fuel costs pursuant to NCUC Rule R8-52(a).

No party offered direct testimony contesting the Company's fuel procurement and power purchasing practices. In the absence of any direct testimony to the contrary, the Commission concludes these practices were reasonable and prudent during the test period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Company witnesses Goode, Green and Evans testified with regard to the actual test year fuel expenses, revenues and sales. In addition, this information was contained in the exhibits and workpapers filed by North Carolina Power pursuant to Commission Rule R8-55(d). The testimony and other data reveal that on actual jurisdictional sales of 2,462,945 MWh of energy, the Company incurred actual jurisdictional expenses of $28,990,618 and collected current period jurisdictional revenues of $29,024,394. The Company's test period fuel revenues exceeded test period fuel expenses by $33,776.

No party offered testimony or evidence challenging any of the evidence relating to the Company's test period level of sales, expenses, revenues and over-collections. The Commission, therefore, concludes that the North Carolina jurisdictional test period levels of retail sales, fuel revenues, fuel expenses and over-collections submitted by the Company are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is found in the testimony of Company witness Evans. Witness Evans testified that consistent with Commission Rule R8-55(d)(2) the Company's system sales data for the twelve-month period ended June 30, 1991, was adjusted by jurisdiction for weather normalization, customer growth and increased usage. Witness Evans adjusted North Carolina jurisdictional retail sales by 48,348 MWh. The adjustment is the sum of adjustments for weather normalization, customer growth and increased usage of 28,787 MWh, 6,934 MWh and 12,627 MWh, respectively.

No party offered testimony or evidence challenging any of the evidence relating to the adjustments for weather normalization, customer growth and increased usage. The Commission, therefore, concludes that the adjustments proposed by the Company are appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is found in the testimony of Company witness Green and the affidavit of Public Staff witness Lam.

Company witness Green testified that the Company achieved an actual systemwide nuclear capacity factor of 69.3% during the test year ended June 30, 1991. He also testified that the Company's generating units are expected to operate at normal levels in the upcoming rate year commencing January 1, 1992 but that three of the Company's four nuclear units are scheduled for refueling outages, each lasting approximately 75 days. Witness Green concluded that the nuclear refueling outages cause the projected capacity factors for three of the Company's four nuclear units (Surry Unit 1 and North Anna Units 1 and 2) to be slightly below the most current NERC five-year (1986-1990) nuclear capacity factor average of 66.69%, while the remaining unit (Surry Unit 2) is projected to operate above the industry average. The Company therefore adjusted its test period system fuel expenses to reflect a normalized system nuclear capacity factor based upon the five-year NERC average of 66.69%.

Company witness Green also calculated adjusted test period system fuel expenses on the basis of actual June 1991 fuel prices with the exception of coal prices which reflect the lower coal costs for the month of September 1991. The affidavit of Public Staff witness Lam affirmed the reasonableness of these adjustments.

The Company's adjusted test period system fuel expenses reflect an adjustment of ($39,562) associated with the aforementioned adjustments. These adjustments are reasonable for purposes of determining test period jurisdictional fuel expenses in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the direct testimony of Company witnesses Goode, Green and Evans and the affidavit of Public Staff witness Lam.

The Company's normalized system fuel expenses of $673,701,104 are divided by the test period adjusted system sales of 57,774,634 MWh to obtain a fuel cost component of 1.166¢/kWh, excluding gross receipts tax. The 1.165¢/kWh base fuel component approved in the Company's last general rate case, Docket No. E-22, Sub 314, is then subtracted from the 1.166¢/kWh fuel cost component. That calculation results in an increment of .001¢/kWh to the 1.165¢/kWh base fuel component.

The Commission concludes that the primary fuel cost component of .001¢/kWh, excluding gross receipts tax, is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

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...." Further, amended Rule R8-55(c)(5) provides: "Pursuant to G.S. 62-130(e), any over-collection of reasonable and prudently incurred fuel costs to be refunded to a utility's customers through operation of the EMF rider, shall include an amount of interest, at such rate as the Commission determines to be just and reasonable, not to exceed the maximum statutory rate."

Company witness Evans testified and Public Staff witness Lam affirmed that the amount of EMF interest (resulting from the over-collection of $33,776) due to the ratepayers is $5,066, pursuant to the Commission's Order of June 24, 1988, in Docket No. E-100, Sub 55, adopting the method for calculating such interest. The Commission concludes that the level of EMF interest of $5,066 applicable to test period over-collections is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is found in the direct testimony of Company witness Evans and the affidavit of Public Staff witness Lam.

The $33,776 of over-recovered fuel expense plus the $5,066 of interest is divided by the test period adjusted North Carolina retail sales of 2,511,293 MWh to obtain an EMF decrement of .002¢/kWh, excluding gross receipts tax.

The Commission concludes that the EMF decrement of .002¢/kWh excluding gross receipts tax, experienced during the period July 1, 1990, through June 30, 1991, is appropriate for use in this proceeding and that the decrement of .002¢/kWh, excluding gross receipts tax, shall remain in effect for a fixed 12-month period beginning January 1, 1992.

IT IS, THEREFORE, ORDERED, as follows:

1. That effective beginning with usage on and after January 1, 1992, North Carolina Power shall adjust the base fuel component in its North Carolina retail rates approved in Docket No. E-22, Sub 314, by an increment of .001¢/kWh to reflect a new primary fuel component of 1.166¢/kWh (excluding gross receipts tax).

2. That an EMF/Rider B decrement of .002¢/kWh (excluding gross receipts tax) be instituted and remain in effect for usage on and after January 1, 1992.

3. That 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 10 days from the date of this Order.

4. That 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 18th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

DOCKET NO. E-22, SUB 329

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of North Carolina Power Pursuant to G.S. 62-133.2 and NCUC Rule R8-55 Relating to Fuel Charge Adjustments for Electric Utilities	NOTICE TO CUSTOMERS OF RATE INCREASE

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission entered an Order in this docket on December 18, 1991, after public hearings, approving a $4.2 million increase in the annual rates and charges paid by the retail customers of North Carolina Power in North Carolina. The rate increase will be effective for electricity used on and after January 1, 1992. The rate increase was ordered by the Commission after a review of North Carolina Power's fuel expenses during the 12-month test period ended June 30, 1991, and represents actual charges experienced by the Company with respect to its reasonable costs of fuel and the fuel component of purchased power during the test period.

For a typical residential customer using 1,000 kWh of electricity per month, the Commission's Order will result in a rate increase of approximately $1.67 from the previously effective rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December 1991.

North Carolina Utilities Commission
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. E-34, SUB 28

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by New River Light and Power Company for Authority to Adjust and Increase Its Electric Rates and Charges	ORDER GRANTING PARTIAL INCREASE IN RATES

HEARD IN: Watauga County Courthouse, West King Street, Boone, North Carolina, on January 24, 1991, at 9:30 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; Commissioners Ruth E. Cook, and Robert O. Wells

APPEARANCES:

For the Applicant:

James M. Deal, Jr., Attorney at Law, Post Office Box 311, Boone, North Carolina 28607
For: New River Light and Power Company

For the Public Staff:

David T. Drooz, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On August 22, 1990, New River Light and Power Company (New River, the Applicant, or the Company) filed an Application with the North Carolina Utilities Commission seeking authority to adjust and increase its rates and charges for electric service to retail customers in North Carolina.

By Order issued on September 20, 1990, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137, suspended the proposed rates for a period of up to 270 days pursuant to G.S. 62-134, set the matter for investigation, set a hearing for January 24, 1991, in Boone, North Carolina, established the test period to be used by all parties to the proceeding as the 12-month period ended December 31, 1989, and required the Company to give notice to its customers of the proposed rate increase and the hearing.

On January 8, 1991, the Public Staff filed Testimony and Exhibits of Jane Rankin, Staff Accountant, Accounting Division and James S. McLawhorn, Electric Engineer, Electric Division. Also on January 8, 1991, a Joint Stipulation was filed.

On January 24, 1991, two (2) protest letters were filed with the Commission.

The matter came on for hearing as ordered on January 24, 1991, at 9:30 a.m., before a Commission Panel for the purpose of hearing testimony from the Company's customers and for the purpose of presenting evidence. No public witnesses appeared or offered testimony at the hearing. The prefiled testimony and exhibits of the Company and of the Public Staff were admitted into evidence by stipulation.

Based upon the verified Application, the testimony and exhibits received into evidence, and the record as a whole of this proceeding, the Commission, having reviewed the proposed orders filed in this proceeding, now makes the following:

FINDINGS OF FACT

1. New River Light and Power Company is the principal electric supplier for the Town of Boone, North Carolina, and for Appalachian State University. New River is wholly owned by Appalachian State University, and is therefore indirectly owned by the State of North Carolina.

2. New River has no generating facilities of its own, but instead purchases all of its power requirements wholesale from Blue Ridge Electric Membership Corporation.

3. New River is lawfully before the Commission seeking an increase in its basic rates and charges for retail electric service pursuant to Chapter 62 of the General Statutes of North Carolina.

4. The test period for purposes of this proceeding is the 12-month period ended December 31, 1989, adjusted for certain changes based upon circumstance and events occurring up to the time of the close of the hearing in this docket.

5. The quality of retail electric service which the Company is furnishing to customers in its service area in and around Boone, North Carolina, is adequate.

6. New River Light and Power Company's reasonable original cost rate base used and useful in providing service to the public within the State of North Carolina is $9,574,985, consisting of electric plant in service of $8,263,838, power supply investments (capital credits) of $3,059,555, and an allowance for working capital of $346,516, reduced by accumulated depreciation of $2,094,924.

7. It is reasonable to reflect an amount of zero in purchase power expense for capital credits/debits in this proceeding.

8. The reasonable level of test year operating revenue deductions for the Company after pro forma adjustments is $9,952,036.

9. Appropriate gross revenues for the Company for the test year, under present rates and after accounting and pro forma adjustments, are $10,690,804.

10. The overall rate of return which the Company should be allowed to earn on original cost rate base is 11.65%. This return is based on a capital structure of 6.58% debt and 93.42% equity, with a cost rate of 6.62% for debt and 12.0% for common equity.

11. Based on the foregoing, New River Light and Power should increase its annual level of gross revenues under present rates by $389,338. The annual revenue requirement approved herein is $11,080,142, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable. The revenue requirement approved herein is based upon the original cost of the Company's property used and useful in providing service to its customers.

12. The Schedule of Rates attached hereto as Appendix A of the Order is found to be just and reasonable and such Schedule should be used by the Company to generate the level of revenues found to be appropriate in this case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1, 2, 3, AND 4

The evidence for these findings is contained in the verified Application, the Commission's files and records regarding this proceeding, the Commission's Orders pursuant to this hearing, the testimony and exhibits of Company witnesses Edwards, Austin, and Cohn, and the testimony and exhibits of Public Staff witnesses Rankin and McLawhorn. These findings are essentially informational, procedural, and jurisdictional in nature and are uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding appears in the testimony of New River witnesses Austin and Cohn. No customers or intervenors complained about the quality of service. The Commission concludes that the quality of service is adequate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

Company witness Austin and Public Staff witness Rankin offered testimony regarding New River's reasonable original cost rate base. Through its attorney, New River stipulated to the adjustments of the Public Staff regarding original cost rate base and accepted the amounts presented in Rankin Exhibit I. The following table summarizes the amounts which the Company and the Public Staff agreed upon for use in this proceeding.

Item	Amount
Electric plant in service	$ 8,263,838
Accumulated depreciation	(2,094,924)
Power supply investments (capital credits)	3,059,555
Working capital allowance	346,516
Total original cost rate base	$ 9,574,985

Based on the foregoing, the Commission concludes that the appropriate original cost rate base for use herein is $9,574,985, calculated as shown above.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding of fact is found in the testimony of Company witness Austin and Public Staff witness Rankin.

Public Staff witness Rankin testified that it is reasonable in the circumstances of this case to have an amount of zero in purchase power expense for capital credits/debits. This position is based on an agreement of the parties which is not binding as to the proper treatment of capital credits/debits in future cases.

Based on the foregoing, the Commission concludes that the appropriate amount of capital credits/debits to be applied against purchase power expense in this proceeding is zero.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witnesses Austin and Edwards and Public Staff witnesses Rankin and McLawhorn. The adjustments to test year operating revenue deductions proposed by the Public Staff were stipulated to by the Company. The following table summarizes the amounts which the Company and the Public Staff agreed upon for use in this proceeding.

Item	Amount
Purchased power	$ 8,457,080
Operation and maintenance	873,985
Franchise tax	353,634
Depreciation	256,619
Miscellaneous	10,718
	$ 9,952,036

The Commission, based on the foregoing, finds and concludes that the reasonable level of test year operating revenue deductions for the purpose of this proceeding is $9,952,036.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witnesses Austin and Edwards and Public Staff witnesses Rankin and McLawhorn.

At the hearing, the Company through counsel stipulated to the Public Staff's level of $10,690,804 for operating revenues under present rates.

Based on the foregoing, the Commission finds that the proper amount of operating revenues under present rates for use herein is $10,690,804.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

This finding of fact is based on the "Joint Stipulation of New River Light and Power Company and the Public Staff" filed January 8, 1991. The parties agreed to the fair and reasonable cost of capital, and no contrary evidence has been presented. The Commission concludes that the cost of capital agreed to by the parties is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The Commission has previously discussed its findings and conclusions regarding the fair rate of return which New River Light and Power should be afforded an opportunity to earn.

The following schedules summarize the gross revenues and the rates of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and the conclusions heretofore and herein made by the Commission.

SCHEDULE I
NEW RIVER LIGHT & POWER COMPANY
Docket No. E-34, Sub 28
STATEMENT OF OPERATING INCOME
Twelve Months Ended December 31, 1989

Item	Present Rates	Approved Increase	Approved Rates
Operating Revenue	$10,690,804	$389,338	$11,080,142
Operating Revenue Deductions			
Purchased Power	8,457,080	0	8,457,080
Operating & Maintenance	873,985	467	874,452
Franchise Tax	353,634	12,537	366,171
Depreciation	256,619	0	256,619
Miscellaneous	10,718	0	10,718
Total Operating Revenue Deductions	9,952,036	13,004	9,965,040
Net Operating Income	$ 738,768	$376,334	$ 1,115,102

SCHEDULE II
NEW RIVER LIGHT & POWER COMPANY
Docket No. E-34, Sub 28
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1989

Item	Amount
Investment in Electric Plant	
Electric Plant in Service	$ 8,263,838
Accumulated Depreciation	(2,094,924)
Power Supply Investment (capital credits)	3,059,555
Working Capital Allowance	346,516
Original Cost Rate Base	$ 9,574,985
Rates of Return	
Present Rates	7.72%
Approved Rates	11.65%

SCHEDULE III
NEW RIVER LIGHT & POWER COMPANY
Docket No. E-34, Sub 28
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1989

Item	Capital-ization Ratio	Original Cost Rate Base	Embeded Cost	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-term Debt	6.58%	$ 630,034	6.62%	$ 41,708
Equity	93.42%	8,944,951	7.79%	697,060
	100.00%	$9,574,985		$ 738,768
	Approved Rates - Original Cost Rate Base			
Long-term Debt	6.58%	$ 630,034	6.62%	$ 41,708
Equity	93.42%	8,944,951	12.00%	1,073,394
	100.00%	$9,574,985		$1,115,102

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence relating to rate design is contained in the testimony and exhibits of Company witness Cohn and Public Staff witness McLawhorn.

At the hearing, the Company through counsel stipulated to the Public Staff's rate design.

Based on the foregoing, the Commission finds that the rate design agreed to by both the Company and Public Staff and the Schedule of Rates attached hereto as Appendix A of this Order are appropriate for use by the Company to generate the level of revenues found to be appropriate in this case.

IT IS THEREFORE, ORDERED as follows:

1. That New River Light and Power Company is hereby allowed to adjust and increase its rates and charges so as to produce annual revenues from operations, including miscellaneous and other revenues, of $11,080,142. This level of operating revenues includes an approved increase in annual rates and charges of $389,338.

2. That the Company shall file, not later than ten days after the date of this Order, revised rate schedules and tariffs which are consistent with Appendix A attached hereto.

3. That New River shall notify its customers of the increased rates approved herein by appropriate bill insert or separate mailing, as shown in Appendix B. Notice shall be mailed within five days of this Order.

4. That, unless suspended by further Order of the Commission, such revised tariffs shall be effective for all service rendered on and after the day notice has been mailed to the customers in accordance with the preceding paragraph.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva Thigpen, Acting Chief Clerk

APPENDIX A

DOCKET NO. E-34, SUB 28
NEW RIVER LIGHT AND POWER COMPANY
RETAIL RATE SCHEDULE

SCHEDULE R (RESIDENTIAL USE)	
Customer Charge per Bill	\$ 5.50
Energy Charge per kWh	\$ 0.070627
SCHEDULE RE (RESIDENTIAL ENERGY MANAGEMENT)	
Customer Charge per Bill	\$ 5.50
Energy Charge per kWh	\$ 0.070627
Load Management Switch Credit	(\$ 2.50)
SCHEDULE G (COMMERCIAL)	
Customer Charge per Bill	\$ 8.00
Energy Charge per kWh	\$ 0.065730
SCHEDULE GE (COMMERCIAL ENERGY MANAGEMENT)	
Customer Charge per Bill	\$ 8.00
Energy Charge per kWh	\$ 0.065730
Load Management Switch Credit	(\$ 2.50)
SCHEDULE GL (LARGE COMMERCIAL)	
Customer Charge per Bill	\$10.00
Demand Charge per kW	\$ 8.55
Energy Charge per kWh	\$ 0.034075
SCHEDULE I (INDUSTRIAL)	
Customer Charge per Bill	\$15.00
Demand Charge per kW	\$ 9.00
Energy Charge per kWh	\$ 0.038989
SCHEDULE A (APPALACHIAN STATE UNIVERSITY)	
Customer Charge per Bill	\$13.00
Energy Charge per kWh	\$ 0.067963
SECURITY LIGHTS	
Flat Charge per Lamp per Bill	\$ 6.43
COMMERCIAL AREA LIGHTS (250 WATT HPS)	
Flat Charge per Lamp per Bill	\$ 8.17

PLUS POWER COST ADJUSTMENT APPLIED ALL RATES ON A kWh BASIS
RATE BASIS: MONTHLY
EFFECTIVE DATE:
AUTHORITY: DOCKET NO. E-34, SUB 28

APPENDIX B

NOTICE TO CUSTOMERS

The North Carolina Utilities Commission issued an Order on February 19, 1991, allowing New River Light & Power Company to increase its rates and charges so as to produce an annual increase in revenues of $389,338, or 3.66%. The Company had originally requested an annual increase in revenues of $484,438, or 4.4%.

A public hearing was held in Boone on January 24, 1991, for the purpose of hearing testimony from the Company's customers and for the purpose of receiving expert testimony on the matter. At the hearing, the Public Staff - North Carolina Utilities Commission and the Company agreed that the appropriate revenue increase should be $389,338. After consideration of the evidence presented in the case, the Commission determined that an annual increase of $389,338 is just and reasonable at this time and should be approved.

The Commission's approved rates reflect a reallocation of charges to the different rate classes of New River based upon a cost-of-service study performed by the Public Staff. New River did not oppose the approved rate structuring. A comparison of a typical bill under present rates and after the approved increase is shown below:

Rate Class	Consumption kWh per Month	Company's Present Rates	Commission Approved Rates	Percent Increase
Residential	500	$38.16	$40.81	6.94%
	1000	$72.82	$76.13	4.55%
General	500	$38.68	$40.87	5.66%
Commercial	2500	$165.42	$172.33	4.18%

The approved rate schedule changes will become effective on service rendered on and after the date of the mailing of this notice and are subject to purchase power adjustments.

DOCKET NO. G-5, SUB 226

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Eaton Corporation, Post Office Box 1728, Kings Mountain, North Carolina 28086, Complainant vs. Public Service Company of North Carolina, Respondent	FINAL ORDER ON REMAND OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

ORAL ARGUMENT HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, February 19, 1991, 10:30 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; and Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, Robert O. Wells, and Charles H. Hughes

APPEARANCES:

For the Public Staff:

David Drooz, Staff Attorney, Public Staff, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For Public Service Company of North Carolina, Inc.

F. Kent Burns, Burns, Day & Presnell, P. A., Attorneys at Law, Post Office Box 10867, Raleigh, North Carolina 27605

BY THE COMMISSION: On December 28, 1990, Commission Hearing Examiner Sammy R. Kirby entered a Recommended Order in this docket ruling on the complaint filed by Eaton Corporation (Complainant) against Public Service Company of North Carolina, Inc. (Respondent). The Hearing Examiner held that Public Service should be required to make a refund to Eaton based upon the difference between the charges made to Eaton and the charges that would have been made under Rate Schedule 60 from May 28, 1984, through December 31, 1984, plus interest.

The Public Staff filed an exception to the Recommended Order on January 14, 1991. By Order dated February 4, 1991, the Commission scheduled an oral argument for February 19, 1991. The matter was thereafter called for oral argument at the appointed time and place. The Public Staff and Public Service presented arguments in support of their respective positions.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The record in this proceeding fully supports each of the findings of fact, conclusions and decretal paragraphs set forth in the Recommended Order. Accordingly, the Commission finds good cause to deny the exception filed by the Public Staff and hereby adopts the Recommended Order as the Final Order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the exception to the Recommended Order filed by the Public Staff on January 14, 1991, be, and the same is hereby, overruled and denied.

2. That the Recommended Order entered in this docket on December 28, 1990, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

3. That Public Service shall make a refund including interest to the Eaton Corporation in conformity with the calculations filed in this docket on January 9, 1991, except that interest shall be accrued through the date the refund is actually made. Public Service shall make this refund not later than ten (10) days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

Commissioner Ruth E. Cook dissents in part.
Chairman William W. Redman, Jr., did not participate in this case.

COMMISSIONER RUTH E. COOK, DISSENTING IN PART:

I hereby renew my previous dissent which was entered in this docket on June 14, 1989. In that dissent, I rejected the Majority's conclusion that G.S. 62-132 was the applicable statute of limitations. I reached the following conclusions regarding the appropriate statute of limitations:

> "The justness and reasonableness of the rates themselves are not at issue in this case. Eaton is simply claiming that Public Service mistakenly and wrongfully failed to reclassify their usage priority. The applicable statute of limitations for such a claim is G.S. 1-52(9). This being the case, I would allow the Complainant to recover the full amount of the overcharge for the period September 1, 1980, through December 31, 1984. This position is consistent with the dissents which I have recently written in two other gas refund cases decided by the Commission in Docket Nos. G-9, Sub 272 and G-5, Sub 226. I hereby incorporate those dissents by reference rather than again repeating all of the reasoning set forth therein."

On appeal, the North Carolina Court of Appeals held that G.S. 62-132 was not the applicable statute of limitations in this case. Therefore, the matter was remanded to the Commission to determine both the appropriate remedy and the proper statute of limitations. In Re Eaton Corp. v. Public Service Co., 99 N.C. App. 174 (1990).

Today, I dissent in part from the Final Order on Remand because I agree with the Public Staff that the Majority has again made an error of law by concluding that Public Service did not make a "mistake" within the meaning of G.S. 1-52(9) and that G.S. 1-52(9) has no application to this case. Eaton relies upon mistake. Public Service made a mistake in failing to properly reclassify Eaton's priority and rate schedule. Eaton also had the mistaken belief that it was properly billed by Public Service. Notwithstanding the fact that Public Service acted in good faith based upon its interpretation of a Commission Order and its own rate schedules, the fact remains, and the Majority has so found, that these interpretations were in error. It is clear that mistake is a basis and element of Eaton's claim. Public Service made a mistake by charging Eaton on the wrong rate. It is illogical to find that a utility has unintentionally overbilled a customer, but then conclude that there was no mistake.

Eaton had no reason, in the exercise of due diligence, to discover the mistake before November 1986, when Eaton's consultant advised that the plant had been on the wrong rate. The testimony clearly indicates that no Eaton employee was familiar with the various rate schedules and priorities approved by the Commission and that a reasonably astute businessman could be confused by the tariff language dealing with alternate fuel capability. The utility was obligated to assist its customers "in selecting the most economical rate schedule," Commission Rule R6-12(2), and Eaton relied upon Public Service to keep it on the proper rate schedule. The record shows that Eaton did not know, and in the exercise of due diligence had no reason to know, that it was on the wrong rate schedule until November 1986. Eaton's claim was timely filed within three years after that date. Eaton is, therefore, legally entitled to a refund for the full period of overcharges.

Commissioner Ruth E. Cook

DOCKET NO. G-5, SUB 227

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Blue Ridge Textile Printers, Inc., (James F. Gennusa, President), Post Office Box 5334, Statesville, North Carolina 28677, Complainant vs. Public Service Company of North Carolina, Respondent	FINAL ORDER ON REMAND OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

ORAL ARGUMENT
HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, February 19, 1991, 10:30 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; and Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, Robert O. Wells, and Charles H. Hughes

APPEARANCES:

For the Public Staff:

David Drooz, Staff Attorney, Public Staff, Post Office Box 29520, Raleigh, North Carolina 27626-0520.
For: The Using and Consuming Public

For Public Service Company of North Carolina, Inc.

F. Kent Burns, Burns, Day & Presnell, P. A., Attorneys at Law, Post Office Box 10867, Raleigh, North Carolina 27605

BY THE COMMISSION: On December 28, 1990, Commission Hearing Examiner Sammy R. Kirby entered a Recommended Order in this docket ruling on the complaint filed by Blue Ridge Textile Printers, Inc. (Complainant), against Public Service Company of North Carolina, Inc. (Respondent). The Hearing Examiner held that Public Service should be required to make a refund to Blue Ridge based upon the difference between the charges made to Blue Ridge and the charges that would have been made under Rate Schedules 60 and 20 from May 7, 1984, through July 31, 1989, plus interest.

The Public Staff filed an exception to the Recommended Order on January 14, 1991. By Order dated February 4, 1991, the Commission scheduled an oral argument for February 19, 1991. The matter was thereafter called for oral argument at the appointed time and place. The Public Staff and Public Service presented arguments in support of their respective positions.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The record in this proceeding fully supports each of the findings of fact, conclusions and decretal paragraphs set forth in the Recommended Order. Accordingly, the Commission finds good cause to deny the exception filed by the Public Staff and hereby adopts the Recommended Order as the Final Order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the exception to the Recommended Order filed by the Public Staff on January 14, 1991, be, and the same is hereby, overruled and denied.

2. That the Recommended Order entered in this docket on December 28, 1990, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

3. That Public Service shall make a refund including interest to Blue Ridge in conformity with the calculations filed in this docket on January 9, 1991, except that interest shall be accrued through the date the refund is actually made. Public Service shall make this refund not later than ten (10) days from the date of this Order.

ISSUED BY ORDER OF THE COMMISSION.
This the 4th day of March 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

Commissioner Ruth E. Cook dissents in part.
Chairman William W. Redman, Jr., did not participate in this case.

COMMISSIONER RUTH E. COOK, DISSENTING IN PART:

I hereby renew my previous dissent which was entered in this docket on June 5, 1989. In that dissent, I rejected the Majority's conclusion that G.S. 62-132 was the applicable statute of limitations. I reached the following conclusions regarding the appropriate statute of limitations:

> "I believe that the applicable statute of limitations is the three-year period provided in G.S. 1-52(2), which deals with a claim created by statute for which no other limitation period is provided in the statute creating the claim. See also G.S. 1-15(a). I also believe that G.S. 1-52(9), which provides that a claim based on mistake does not accrue until the claimant discovers the facts constituting the mistake, is applicable. Applying these two statutes, I conclude that the Complainant's claim accrued in November 1986, that it had three years thereafter within which to institute its action, that its action was timely, and that no part of the Complainant's claim is barred. (Footnote omitted). I would allow the Complainant to recover the full amount of the overcharge for the period beginning September 1, 1981."

On appeal, the North Carolina Court of Appeals held that G.S. 62-132 was not the applicable statute of limitations in this case. Therefore, the matter was remanded to the Commission to determine both the appropriate remedy and the proper statute of limitations. In Re Blue Ridge Textile Printers v. Public Service Co., 99 N.C. App. 193 (1990).

Today, I dissent in part from the Final Order on Remand because I agree with the Public Staff that the Majority has again made an error of law by concluding that Public Service did not make a "mistake" within the meaning of G.S. 1-52(9) and that G.S. 1-52(9) has no application to this case. Blue Ridge relies upon mistake. Public Service made a mistake in failing to properly reclassify Blue Rige's priority and rate schedule. Blue Ridge also had the mistaken belief that it was properly billed by Public Service. Notwithstanding the fact that Public Service acted in good faith based upon its interpretation of a Commission Order and its own rate schedules, the fact remains, and the Majority has so found, that these interpretations were in error. It is clear that mistake is a basis and element of Blue Ridge's claim. Public Service made a mistake by charging Blue Ridge on the wrong rate. It is illogical to find that a utility has unintentionally overbilled a customer, but then conclude that there was no mistake.

Blue Ridge had no reason, in the exercise of due diligence, to discover the mistake before November 1986, when its consultant advised that the plant had been on the wrong rate. The testimony clearly indicates that no Blue Ridge employee was familiar with the various rate schedules and priorities approved by the Commission and that a reasonably astute businessman could be confused by the tariff language dealing with alternate fuel capability. The utility was obligated to assist its customers "in selecting the most economical rate schedule," Commission Rule R6-12(2), and Blue Ridge relied upon Public Service to keep it on the proper rate schedule. The record shows that Blue Ridge did not know, and in the exercise of due diligence had no reason to know, that it was on the wrong rate schedule until November 1986. Blue Ridge's claim was timely filed within three years after that date. Blue Ridge is, therefore, legally entitled to a refund for the full period of overcharges.

Commissioner Ruth E. Cook

DOCKET NO. G-5, SUB 270

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Eaton Corporation, Manufacturing Services Center, 32500 Chardon Road, Willoughby Hills, Ohio 44094, Complainant v. Public Service Company of North Carolina, Inc., Respondent	FINAL ORDER OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

ORAL ARGUMENT
HEARING IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on June 13, 1991, at 10:00 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, and Charles H. Hughes

APPEARANCES:

For the Complainant:

James C. Windham, Jr., Scott, Hollowell, Palmer, and Windham, Attorneys at Law, Post Office Box 995, Gastonia, North Carolina 28053-0995

For the Respondent:

F. Kent Burns, Burns, Day & Presnell, P.A., Attorneys at Law, Box 2479, Raleigh, North Carolina 27602

BY THE COMMISSION: On April 5, 1991, Commission Hearing Examiner Sammy R. Kirby entered a Recommended Order in this docket denying the complaint which Eaton Corporation (Eaton) filed against Public Service Company of North Carolina, Inc. (Public Service). Attached to the complaint, which was filed on April 20, 1990, were (1) a copy of the Commission's notice showing the April 4, 1988, amendment to NCUC R6-19.2(f) and (2) a history of the monthly gas consumption and bills for Eaton's plant in Fletcher, North Carolina. Eaton's plant in Fletcher is served by Public Service Company. Eaton claimed it should be have charged on Rate Schedule 20 instead of Rate Schedules 17 and 18 for its natural gas consumption during the period from September 1, 1988, to November 8, 1989. the complaint asked for a refund with interest.

On April 22, 1991, Eaton filed certain exceptions to the Recommended Order denying the Company's complaint and requested the Commission to schedule an oral argument to consider those exceptions.

By Order entered in this docket on April 30, 1991, the Commission scheduled an oral argument on exceptions for June 13, 1991, at 10:00 a.m.

The matter subsequently came on for oral argument on exceptions at the appointed time and place. James C. Windham, Jr., offered oral argument in support of Eaton's exceptions. F. Kent Burns, counsel for Public Service, offered oral argument in opposition to the exceptions and in support of the Recommended Order.

Based upon a careful consideration of the entire record in this proceeding, the Commission concludes that all of the findings of fact, conclusions, and the decretal paragraph contained in the Recommended Order of April 5, 1991, are fully supported by the record; that the Recommended Order should be affirmed and adopted as the Final Order of the Commission; and that each of the exceptions filed by Eaton Corporation should be overruled and denied.

IT IS, THEREFORE, ORDERED as follows:

1. That the exceptions filed by Eaton Corporation with respect to the Recommended Order entered in this docket on April 5, 1991, be, and the same are hereby, denied.

2. That the Recommended Order entered in this docket by Hearing Examiner Sammy R. Kirby on April 5, 1991, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 24th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-9, SUB 302

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Hatteras Yachts, Inc., Complainant v. Piedmont Natural Gas Company, Inc. Respondent	)	FINAL ORDER RULING ON EXCEPTIONS

ORAL ARGUMENT
HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Thursday, July 11, 1991, at 10:00 a.m.

BEFORE: William W. Redman, Jr., Chairman, Commissioners Sarah Lindsay Tate, J. A. Wright, Robert O. Wells, Charles H. Hughes, Laurence A. Cobb, Allyson K. Duncan

APPEARANCES:

For the Complainant:

David T. Drooz, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For the Respondent:

Jerry W. Amos, Brooks, Pierce, McLendon, Humphrey & Leonard, Attorneys at Law, Post Office Drawer U, Greensboro, North Carolina 27402

BY THE COMMISSION: On March 28, 1991, the Commission Hearing Examiner entered a Recommended Order Granting Complaint in this docket requiring Respondent Piedmont to make a refund to Complainant Hatteras Yachts. The refund was to be based upon the difference in the charges made to Hatteras for 78.8% of the gas consumed on Hatteras Account No. 230499922371 and the charges that would have been made for that gas under Rate Schedule 104 from September 2, 1978, to April 28, 1989, plus 10% interest compounded annually.

On April 2, 1991, Piedmont filed Exceptions and Request for Hearing. Piedmont noted numerous exceptions to the Recommended Order and requested a hearing de novo before a panel of Commissioners or the full Commission. Piedmont also asked that it not be required to calculate the refund required by the Recommended Order until after the Commission rules on the Exceptions. On April 3, 1991, the Public Staff filed a Response opposing the request for a hearing de novo.

On May 13, 1991, the Commission issued its Order Scheduling Oral Argument. The Commission scheduled oral argument on the Exceptions and deferred the calculation of the refund and interest.

Oral argument was held as scheduled on July 11, 1991. Both Hatteras and Piedmont appeared through counsel and presented oral argument. The Commission then took the matter under advisement. In deciding this case, the Commission has given careful consideration to the Recommended Order Granting Complaint, the Exceptions filed by Piedmont, the oral argument of counsel, and the entire record in this proceeding.

As to the issue of Piedmont's liability for a refund to Hatteras, the Commission agrees with the Hearing Examiner that Piedmont should make a refund based upon the difference in the charges made to Hatteras for 78.8% of the gas consumed on the subject account and the charges that would have been made for that gas under Rate Schedule 104 from September 2, 1978, to April 28, 1989, plus interest at the rate of 10% compounded annually. The refund must be made because G. S. 62-139(a) prohibits a public utility from charging a rate which varies from its tariffs. It provides as follows:

> No public utility shall directly or indirectly, by any device whatsoever, charge, demand, collect or receive from any person a greater or less compensation for any service rendered or to be rendered by such public utility than that prescribed in the schedules of such public utility applicable thereto then filed in the manner provided in this Article. . . (Emphasis added).

The Hearing Examiner concluded, based upon his findings of fact, that the 78.8% of gas that was burned in the boiler should have been billed on Rate 104 and that Piedmont violated G. S. 62-139 by charging Hatteras Yachts on Rate 103, instead of Rate 104, for the gas burned in the boiler. The Hearing Examiner reasoned in part as follows:

> Hatteras's boiler gas did not qualify for Rate Schedule 103, which specified that it was for priority 2 customers with plant protection, feedstock or process use "as defined by the North Carolina Utilities Commission in Rule R6-19.2," since Rule R6-19.2 defined such uses as mutually exclusive of alternate fuel capability and Hatteras had alternate fuel capability. . .

> By virtue of burning gas in a boiler in an industrial plant, and using over 50 Mcf or dekatherms per day, Hatteras did not belong on priority 2.5 and Rate Schedule 103. As shown on Exhibit WS-28, Hatteras's boiler gas would have qualified for priority 6 as of November 1, 1977. The lower priorities were later redefined, so by the beginning of 1979 Hatteras's boiler gas would have fallen under priority 3. . . Under either priority 6 or priority 3, Hatteras qualified for Rate Schedule 104 as it existed from September 2, 1978, up to April 1, 1989. The availability provisions of Rate Schedule 104 during that period simply provided that it was for non-residential customers who were not in priorities 1 or 2. This plainly applied to Hatteras, since as an industrial customer its boiler use and alternate fuel capability were two factors that each independently excluded Hatteras from priorities 1 and 2. . .

The Commission agrees with this reasoning and concludes that a refund must be made. All exceptions inconsistent with this reasoning are overruled.

On the issue of the statute of limitations, the Commission concludes that all of the findings and conclusions contained in the Recommended Order Granting Complaint dealing with the statute of limitation issue are fully supported by the record and should be affirmed and adopted as the findings and conclusions of the Commission on this issue. All exceptions inconsistent herewith are overruled.

As to the issue of an offset, the Commission cannot adopt the findings and conclusions of the Recommended Order. The Recommended Order found as a fact, "Piedmont did not undercharge for the gas burned in the make-up units." The Recommended Order concluded, "Piedmont has neither pleaded nor made out a case that Hatteras has been under billed on any of its gas service. Therefore, Piedmont is not entitled to any offset for the refund. . . " In denying an offset, the Hearing Examiner reasoned that Piedmont had filed no pleadings for an underpayment, that Piedmont had a duty to separately meter the gas for the makeup units, and that Piedmont had not established that the gas for the makeup units should have been billed on the higher Rate 102. The Commission cannot agree.

Instead, the Commission finds as facts that during the time in question Rate Schedule 102 was available "to industrial users with peak day requirements less than 50 dekatherms per day classified in Priority 2," that Hatteras burned approximately 21.2% of its natural gas in make-up units, that the make-up units burned less than 50 dekatherms of gas per day, that the make-up units did not have alternate fuel capability installed, and that the only evidence with respect to alternate fuel capability for the make-up units was that Hatteras planned to reconfigure the plant so that it could use heat from the boilers in place of heat from the make-up units. The Commission concludes that the make-up units did not have alternate fuel capability during the time in question, that the make-up units came within the terms of Rate Schedule 102, that Piedmont undercharged and Hatteras underpaid for the gas burned in the make-up units, and that Piedmont is entitled to recover the deficiency but has waived its right to recover any amount greater than the amount of the refund that it must make to Hatteras.

It is true that Piedmont made no mention of an offset in its answer and filed no pleading to recover underpayments as to the 21.2% of the gas that was burned in the make-up units. However, the Commission finds no grounds for denying an offset on this basis. Hatteras never alleged in its complaint that its claim for refund only applied to the 78.8% of the gas burned in the boiler. Both claims were refined during the course of discovery and the hearing. It is

well established that

> [g]reat liberality is indulged in pleadings in proceedings before the Commission, and the technical and strict rules of pleading applicable in ordinary court proceedings do not apply. The Commission may adopt its own rules governing pleadings, and has the power to waive or suspend the rules. It may enlarge or restrict the inquiry before it unless a party is clearly prejudiced thereby. 73 C.J.S., s. 52, p. 1119. Such liberality and informality is essential to the workings of the Commission.

Utilities Commission v. Area Development, Inc. 257 NC 560, 569 (1962). Hatteras did not object when Piedmont witness Schieffer testified that the gas consumed in the make-up units should have been billed on the higher Rate Schedule 102 and presented Piedmont's calculation of the underpayment as an offset to any refund. In such circumstances, Hatteras cannot now argue that the offset issue should be denied for lack of a formal pleading.

Neither does the Commission find Piedmont's failure to separately meter the boilers and the make-up units to be grounds for rejecting the offset claim. We have already cited G. S. 62-139(a) for the proposition that a utility shall not collect "a greater or less compensation" than that prescribed by the applicable tariff. Piedmont's failure to meter does not defeat either this statute or the offset claim. Cf. City of Wilson v. Carolina Builders, 94 NC App. 117 (1989). Testimony was presented to provide estimates of the amount of gas consumed in the boilers and in the make-up units. This testimony provides a basis for measuring the offset just as it provides the basis for measuring the refund.

Finally, the Commission cannot agree with the Hearing Examiner's conclusion that the gas for the make-up units did not belong on the higher Rate Schedule 102. Hatteras witness Hick testified that he plans to reconfigure the plant to use heat from the boilers in place of heat from the make-up units. He testified that "we plan to be able to use the boilers throughout the plant and when we are curtailed, we plan to switch to fuel oil for a hundred percent of that plant." From this, the Hearing Examiner concluded that the make-up units had alternate fuel capability even though the capability was not in fact installed. The Commission cannot agree. We recognize that the definition of alternate fuel capability in effect at the time included a situation "where an alternate nongaseous fuel could have been utilized whether or not the facilities for such use have actually been installed." However, the testimony does not bring the make-up units within this definition since there is no indication that facilities are being installed to switch over the make-up units themselves to fuel oil. Reconfiguring the plant to use heat from the boilers in place of heat from the make-up units does not come within the definition. Since the make-up units did not have alternate fuel capability, they belonged on Priority 2 and Rate Schedule 102. Hatteras has underpaid for this gas, and Piedmont is entitled to recover the proper charges as an offset.

The Commission believes that the offset should run back to 1978, just like the refund. The same mistake that resulted in 78.8% of the gas being overcharged, resulted in 21.2% of the gas being undercharged. Therefore, the Commission would reach the same result as to the statute of limitations and the appropriate period of offset. We do not reach the same conclusion as to the addition of interest. G. S. 62-130(e) specifically authorizes the addition of interest when a utility overcharges a customer and must make a refund. There is no comparable statute authorizing interest when the utility undercharges a customer and later seeks to make up the underpayment. The Commission has traditionally denied interest in such a situation, and we reach that conclusion here.

The Commission therefore finds good cause to rule on the exceptions filed herein by overruling them in part and allowing them in part consistent with the discussion above. The Commission will require Piedmont to calculate the refund and offset and will allow both Hatteras and the Public Staff an opportunity to review the calculations and file comments. In making the calculations, Piedmont shall (1) calculate the refund with interest according to the Recommended Order, (2) calculate separately the underpayment on 21.2% of the gas for the same time period but without interest, and (3) net the two calculations. Should the net figure favor Piedmont, there shall be no recovery since Piedmont waived the right to recover any amount beyond the amount of the refund during oral argument.

IT IS, THEREFORE, ORDERED as follows:

1. That the Exceptions filed by Piedmont in this docket on April 2, 1991, should be, and the same hereby are, overruled in part and allowed in part consistent with the reasoning and provisions of this Final Order;

2. That Piedmont shall make a refund to Hatteras based upon the difference in the charges made to Hatteras for 78.8% of the gas consumed on the subject account and the charges that would have been made for that gas under Rate Schedule 104 from September 2, 1978, to April 28, 1989, plus 10% interest compounded annually;

3. That Piedmont shall be entitled to an offset based upon the difference in the payments made by Hatteras for 21.2% of the gas consumed on the subject account and the payments that would have been made for that gas under Rate Schedule 102 from September 2, 1978, to April 28, 1989; and

4. That Piedmont shall calculate the amount of the refund, calculate the amount of the offset, net the two calculations, and file and serve its

calculations within ten working days from the date of this Final Order, and Hatteras and the Public Staff shall have ten working days thereafter within which to review the calculations and file comments with the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-3, SUB 167

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application of Pennsylvania and Southern Gas Company (North Carolina Gas Service Division) for an Adjustment of Its Rates and Charges	)))	ORDER GRANTING INCREASE IN RATES AND CHARGES

HEARD IN: Wrenn Room, Reidsville Branch of the Rockingham Public Library System, 204 West Morehead Street, Reidsville, North Carolina, on Monday, June 17, 1991, at 10:00 a.m.

Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, June 18, 1991, at 10:00 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; Commissioners Sarah Lindsay Tate and Robert O. Wells

APPEARANCES:

For the Applicant:

James T. Williams, Jr., Attorney at Law, Brooks, Pierce, McLendon, Humphrey and Leonard, Post Office Drawer U, Greensboro, North Carolina 27402

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., Post Office Box 1269, Morganton, North Carolina 28655

For the Public Staff:

Gisele L. Rankin, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

For the Attorney General of North Carolina:

Thomas D. Zweigart, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

BY THE COMMISSION: On March 7, 1991, Pennsylvania and Southern Gas Company (North Carolina Gas Service Division) (hereinafter Pennsylvania and Southern or Company) filed an application with the Commission for authority to adjust and increase its rates and charges for retail natural gas service in North Carolina. The increase sought in the Company's original application was $370,052.

On March 11, 1991, the Carolina Utility Customers Association, Inc., (CUCA) filed a Petition to Intervene. The Commission allowed the Petition by Order issued March 14, 1991.

By Order issued on April 3, 1991, the Commission declared the matter to be a general rate case, suspended the proposed rates and charges, scheduled the matter for hearing in Reidsville and Raleigh, North Carolina, and required the Company to give notice of its application to the public.

On April 18, 1991, the Attorney General filed Notice of Intervention pursuant to G.S. 62-20. The Public Staff - North Carolina Utilities Commission (Public Staff) also intervened on behalf of the using and consuming public.

The Public Staff prefiled the testimony of Jeffrey L. Davis, an engineer with the Public Staff's Natural Gas Division, on May 29, 1991.

On May 30, 1991, the Company filed an amended Exhibit No. 7 and related schedules which reflected the Company's agreement with issues raised by the Public Staff. This amendment lowered Pennsylvania and Southern's requested increase to $369,851.

Affidavits of publication were filed by the Company showing that public notice had been given as required by the Commission's Order.

A public hearing was held in Reidsville for the specific purpose of receiving testimony from public witnesses. Four public witnesses were presented by CUCA. They were: Douglas W. Dorris, on behalf of Fieldcrest Cannon; Joe Dillon, on behalf of Macfield, Inc.; Vernon Moore, on behalf of Pine Hall Brick Company; and Jim Waynick, Director of Personnel with Equity Group.

The case in chief came on for hearing as scheduled in Raleigh. The Company presented the testimony of Bernard L. Smith, Treasurer and Controller of Pennsylvania and Southern, and James W. Carl, Vice-President for Pennsylvania and Southern.

The Public Staff presented the testimony of Jeffrey L. Davis, Engineer, Natural Gas Division of the Public Staff.

On July 18, 1991, the Attorney General filed a letter stating that it did not intend to file a brief or proposed order in this docket. Pursuant to the Commission's July 25, 1991, Order, proposed orders were submitted by Pennsylvania and Southern, the Public Staff, and CUCA on August 7, 1991.

Based upon the verified application, the amended application, the testimony and exhibits received into evidence in this proceeding and the record as a whole, the Commission makes the following:

FINDINGS AND CONCLUSIONS

1. The Company is engaged in the business of transporting, distributing and selling natural gas at retail in a service area consisting of Rockingham County, North Carolina, and a part of Stokes County, North Carolina.

2. Among other things, the Company is seeking an increase in its rates and charges for natural gas service to its North Carolina customers.

3. No party has raised a question with respect to the jurisdiction of the Commission over the matters at issue in this case.

4. The Company is a public utility within the meaning of G.S. 62-3(23).

5. The Commission has jurisdiction over, among other things, the rates and charges of public utilities, including the Company.

6. The Company's application, testimony, exhibits, N.C.U.C. Form G-1 and publication of notices of hearing are in compliance with the provisions of Chapter 62 and the Rules and Regulations of the Commission.

7. The Company is properly before the Commission for a determination of the justness and reasonableness of its rates and charges as regulated by the Commission under Chapter 62 of the General Statutes of North Carolina.

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8. The Company and the Public Staff were the only parties who submitted evidence in this case with respect to revenues, expenses and rate base. Their recommendations reflect a test period of the 12 months ended September 30, 1990, adjusted for certain known changes occurring after the end of the test period and before conclusion of the hearing as permitted by G.S. 62-133(c). The other parties in this proceeding did not object to the use of this test period.

9. It is appropriate to establish a test period of 12 months, ending as close as practicable to the end of the hearing. G.S. 62-133; N.C.U.C. Rule R1-17(c).

10. The appropriate test period for use in this proceeding is the 12 months ended September 30, 1990, adjusted for certain known changes occurring after the end of the test period.

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11. Under the terms and conditions of a Settlement Proposal between the Commission Staff, the Company, and the Public Staff in Docket No. G-3, Sub 157 (hereinafter "the Settlement Proposal") which was accepted as settlement by the Commission on March 28, 1991, Pennsylvania and Southern has agreed to remedy certain alleged safety violations by undertaking to perform and complete certain maintenance and safety work on its natural gas distribution system.

12. The Company has added substantially to its staff since its last rate case in order to meet system maintenance requirements, comply with federal and

state regulatory requirements, and meet the needs associated with the growth of the system.

13. As long as Pennsylvania and Southern complies with the Settlement Proposal, the service which it provides to its North Carolina retail customers is considered adequate.

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14. Prior to the hearing, Pennsylvania and Southern agreed to all the Public Staff's adjustments other than its rate design proposals and incorporated those accounting, end-of-period and pro forma adjustments into the Company's amended Exhibit No. 7 and related schedules. This amendment lowered Pennsylvania and Southern's requested increase from $370,052 to $369,851. The other parties in this proceeding, the Attorney General and CUCA, did not object to the proposed levels of revenues, expenses and rate base agreed to by the Company and the Public Staff.

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15. The weather-normalized level of annual sales and transportation volumes agreed to by the Company and the Public Staff for use in this proceeding is 2,796,586 dekatherms (dts). Applying the Company's approved rates effective November 1, 1990, to this level of sales and transportation volumes and including miscellaneous revenues of $9,162, will produce pro forma test period revenues of $14,104,905.

16. G.S. 62-133(2) requires the Commission to estimate the Company's revenues under present rates.

17. Test period data should be adjusted to reflect any abnormality having a probable impact on the Company's revenues. G.S. 62-133(f); Utilities Commission v. Thornburg, 316 N.C. 238, 252, 342 S.E. 2d 28, 37-38 (1986); Utilities Commission v. Carolina Utility Customers Association, 314 N.C. 171, 189, 333 S.E. 2d 259, 270 (1985).

18. The appropriate level of operating revenues from the sale and transportation of gas under present rates after accounting, pro forma and end-of-period adjustments and including miscellaneous revenues is $14,104,905.

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19. The Company and the Public Staff agreed that the properly adjusted cost of purchased gas under present rates is $9,780,085 (based upon pro forma sales of 2,796,586 dts).

20. The Company and the Public Staff agreed that the properly adjusted level of operation and maintenance expenses under present rates is $2,658,926.

21. The Company and the Public Staff agreed that the properly adjusted level of depreciation expense under present rates is $301,750.

22. The Company and the Public Staff agreed that the proper on-going levels of general taxes, state income taxes, and federal income taxes under present rates are $630,799, $23,944 and $91,467, respectively.

23. The Company and the Public Staff agreed that the proper level of operating revenue deductions under present rates is $13,486,971 which is the sum of the various pro forma expenses under present rates, as discussed hereinabove.

24. The Company's appropriate level of operating revenue deductions under present rates is $13,486,971, consisting of cost of purchased gas expenses of $9,780,085, operation and maintenance expenses of $2,658,926, depreciation expense of $301,750, general taxes of $630,799, state income taxes of $23,944 and federal income taxes of $91,467.

25. Net operating income for return is the result of subtracting total operating revenue deductions of $13,486,971 from total operating revenues of $14,104,905.

26. The appropriate level of net operating income for return under present rates is $617,934, as agreed to by the parties.

27. The Company and the Public Staff agreed that the level of gas utility plant in service at the end of the test period after making appropriate adjustments is $10,892,074.

28. The Company and the Public Staff agreed that the properly adjusted level of accumulated depreciation at the end of the test period is $3,399,449.

29. The Company and the Public Staff agreed that the properly adjusted level of working capital allowance for the test period is $956,755.

30. The Company and the Public Staff agreed that the properly adjusted level of accumulated deferred income taxes for the test period is $762,301.

31. The Company and the Public Staff agreed that the properly adjusted level of deferred pension liability for the test period is $127,180.

32. The Company and the Public Staff agreed that the properly adjusted level of pre-1972 job development investment tax credits for the test period is $3,293.

33. The sum of gas utility plant in service of $10,892,074 and the allowance for working capital of $956,755 reduced by accumulated depreciation of $3,399,449, accumulated deferred income taxes of $762,301, deferred pension liability of $127,180 and pre-1972 job development investment tax credits (pre-1972 JDITC) of $3,293 as proposed by the Company and the Public Staff results in a proposed original cost rate base of $7,556,606 for the test period and is appropriate for use in this proceeding.

34. G.S. 62-133(b)(1) requires the Commission to ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within North Carolina, less that portion of the cost which has been consumed by previous use recovered by depreciation expense.

35. The original cost rate base for the test period of $7,556,606, as proposed by the Company and the Public Staff, is used and useful, or will be used and useful within a reasonable time after the test period, in providing public utility service in North Carolina and is appropriate for use in this proceeding.

36. The return on the Company's original cost rate base under present rates is 8.18% which is calculated by dividing the net operating income for return under present rates of $617,934 by the original cost rate base of $7,556,606.

37. The Company and the Public Staff agreed that the appropriate capital structure for use in this proceeding consists of 53% long-term debt and 47% common equity. This is the same capital structure that was set forth in the Commission's Order of March 28, 1991, in Docket No.G-3, Sub 157, relating to the Settlement Proposal.

38. The Company and the Public Staff agreed that the appropriate embedded cost of long-term debt is 9.77% and that the appropriate return on common equity is 12.55%. These cost rates for long-term debt and common equity capital are the same cost rates that were set forth in the Commission's Order of March 28, 1991, in Docket No.G-3, Sub 157, relating to the Settlement Proposal.

39. Using the recommended capital structure of 53% long-term debt and 47% common equity and an embedded cost of 9.77% for long-term debt, the return on common equity under present rates is 6.38%. This 6.38% return is mathematically determined by dividing the net operating income, under present rates, left over after the payment of interest on long-term debt by the common equity portion of the original cost rate base.

40. The capital structure consisting of 53% long-term debt and 47% common equity and the associated cost rates of 9.77% and 12.55%, respectively, as recommended by the Company and the Public Staff, are appropriate for use in this proceeding. This capital structure is representative of the levels the Company can be expected to experience prospectively.

41. Combining a return on common equity of 12.55% with the capital structure and cost of long-term debt heretofore determined to be appropriate yields an overall return of 11.08% to be applied to the Company's original cost rate base. These returns will balance the interest of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4):"...(to) enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable

requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors."

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42. In order to provide the Company with the opportunity to earn the returns found appropriate herein, the Commission finds it necessary to increase the Company's annual revenues by $369,851.

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43. The Company's and Public Staff's proposal that any changes in existing demand and storage costs (fixed gas costs) will be charged on a uniform basis across all sales and transportation volumes and that a true-up of all fixed gas costs will continue on an annual basis, and shall apply to actual volumes sold and transported is reasonable, appropriate, and should be approved.

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44. The Company provides natural gas sales and transportation service to several different types of customers. The Company's customer mix is 87.3% residential, 12.5% commercial, 0.1% firm industrial, and 0.1% interruptible industrial. The Company makes approximately 28.4% of its sales (including transportation volumes) to residential customers, 19.1% to commercial customers, 13.6% to firm industrial customers, and 38.9% to interruptible industrial customers.

45. The Company provides natural gas service under existing rates to residential customers under Rate Schedule No. 101; to commercial customers and schools under Rate Schedule No. 102; to outdoor lighting customers under Rate Schedule No. 103; to industrial customers using natural gas for process, feedstock, and plant protection purposes using less than 50 dekatherms per day with no alternate fuel capability under Rate Schedule No. 201; to industrial customers using natural gas for process, feedstock, and plant protection purposes with no alternate fuel capability using between 50 and 300 dekatherms of natural gas per day under Rate Schedule No. 205; to industrial customers using natural gas for process, feedstock, and plant protection purposes with no alternate fuel capability using between 300 and 3,000 dekatherms of natural gas per day under Rate Schedule No. 206; to all industrial customers not covered by any other rate schedule entitled to service under existing priority numbers three through five under Rate Schedule No. 208; and to industrial customers using natural gas for boiler fuel purposes only using in excess of 300 dekatherms per day under Rate Schedule No. 600.

46. The Company's existing Rate Schedule Nos. 201, 205, 206, and 208 all apply to industrial customers using gas for process, feed stock, and plant protection purposes.

47. The only differences between customers eligible for service under Rate Schedule Nos. 201, 205, 206, and 208, are their daily natural gas consumption and their priorities under the Commission's former priority rules.

48. Customers served under the Company's existing Rate Schedule Nos. 205, 206, and 208 exhibit similar characteristics in the manner in which they use natural gas, the times at which they use natural gas, and the pattern in which they consume natural gas.

49. Pennsylvania and Southern has proposed to redesign its rate structure so that customers currently served under Rate Schedule Nos. 102 and 201 will receive service under Rate Schedule No. 102; customers served under existing Rate Schedule Nos. 205, 206, and 208 will receive service under a new Rate Schedule No. 104; and customers served under Rate Schedule Nos. 206, 208, and 600 may receive service under a new Rate Schedule No. 105 by meeting the required criteria.

50. The Company's proposal to consolidate Rate Schedule Nos. 205, 206, and 208 into new Rate Schedule No. 104, which is available to all customers using in excess of 1,500 dekatherms per month in any month during a 24 month period adjusted for curtailment and cycle length without the necessity for alternative fuel capability, is reasonable, appropriate, and should be approved.

51. The only difference between customers served under current Rate Schedule Nos. 102 and 201 is the general activity in which that customer engages and the purpose for which that customer uses natural gas.

52. The Company's proposal to consolidate existing Rate Schedule Nos. 102 and 201 into a combined Rate Schedule No. 102 applicable to service rendered to commercial establishments, churches, and industries with a maximum monthly use of no more than 1,500 dekatherms in any two year period is reasonable, appropriate, and should be approved.

53. The Company has proposed to create a new Rate Schedule No. 105, under which interruptible service is to be provided to customers whose natural gas usage during any month in an indicated two year period exceeds 1,500 dekatherms adjusted for curtailment and cycle length so long as the customer agrees to interruption or curtailment of service upon one hour's notice and has alternate fuel capability.

54. Proposed Rate Schedule No. 105 would be available to any customer served under existing Rate Schedule No. 600 and any customer served under existing Rate Schedule Nos. 206 and 208 who otherwise meets the criteria for and elects to receive service under Rate Schedule No. 105.

55. The Company's proposal to implement proposed Rate Schedule No. 105 is reasonable, appropriate, and should be approved.

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56. The Company's existing rate schedules do not contain a summer/winter differential.

57. The cost of service in winter periods, particularly as a result of storage-related costs and higher winter demand, is higher than the cost of service provided during other times of the year.

58. As a result of this cost difference, it is appropriate for Pennsylvania and Southern to include seasonal differentials in its North Carolina retail sales rate schedules, with charges for service rendered in the winter months to be higher than charges for such service during the remainder of the year.

59. The only cost-of-service studies in the present record were prepared and presented by the Public Staff.

60. The Public Staff's cost-of-service studies assigned all fixed costs to customer classes utilizing the "Seaboard" method.

61. Under the Public Staff's "Seaboard" methodology, fixed costs which could not be directly assigned were allocated to customer classes using a composite allocation factor under which 50% of the fixed costs were assigned on the basis of class contributions to the Company's one-day system peak and the remaining 50% were assigned on the basis of adjusted annual sales.

62. The cost-of-service studies prepared by the Public Staff are appropriate for use in this proceeding.

63. It would be unjust and unreasonable to base rate design on cost of service studies alone. Other factors such as volume of service, alternative fuel capability, historical rate design, and the ability of the industrial customer to obtain a negotiated rate are also important considerations in rate design.

64. The rates adopted by the Commission herein will produce movement toward a cost-based level.

65. The rate design proposed by the Public Staff is just and reasonable.

66. The Company, with the Public Staff's support, has proposed the continuation of full margin transportation rates.

67. Under full margin transportation rates, the rate charged by a local distribution company for the transportation of customer-owned gas consists of the applicable sales rate reduced by the commodity cost of gas, applicable gross receipts taxes, and any temporary increments or decrements.

68. The "margin" contained in full margin transportation rates includes fixed gas costs paid by Pennsylvania and Southern to Transco in order to obtain the delivery of natural gas across Transco's interstate pipeline system to the Company's city gate.

69. Entities transporting customer-owned gas are required to separately contract with Transco to obtain the delivery of customer-owned gas across its interstate pipeline network to the company's city gate and separately compensate Transco for providing that service.

70. Pennsylvania and Southern's proposed Rate Schedule No. 106 makes transportation service available, in the Company's discretion, to any customer connected to its system who has obtained an independent supply of natural gas, who has arranged to have this supply delivered to one of the Company's existing delivery points for transportation by the Company to the customer, and who qualifies for the purchase of gas under Rate Schedule Nos. 104 or 105.

71. Full margin transportation rates are just and reasonable.

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72. The rates set forth in Appendix A attached hereto and approved herein are just and reasonable and should be approved. These rates will generate the appropriate level of revenues and will afford Pennsylvania and Southern the opportunity to achieve the approved overall rate of return of 11.08%.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 1 THROUGH 7

The Company filed a verified application on March 7, 1991, seeking, among other things, an increase in its jurisdictional rates and charges. The application was accompanied by the testimony and exhibits of two Company witnesses and N.C.U.C. Form G-1.

On June 18, 1991, the Company filed affidavits of publication stating that notice of the hearing was published in various newspapers in the Company's service area as required by the Commission's Order of April 3, 1991.

In its verified application, the Company stated that it is a corporation organized and existing under the laws of the sate of Delaware and that it is duly domesticated and is engaged in the business of transporting, distributing and selling gas at retail in Rockingham County, North Carolina, and a part of Stokes County, North Carolina. These findings are jurisdictional in nature and essentially informational, uncontested and routine.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 8 THROUGH 10

The evidence for these findings is found in the testimony and exhibits of Company witnesses Smith and Carl, and Public Staff witness Davis.

The Company filed is application and exhibits using a test period of the 12 months ended September 30, 1990. In its April 3, 1991, Order suspending rates the Commission ordered the parties to use a test period consisting of the 12 months ended September 30, 1990, with appropriate adjustments.

These findings, while substantive in nature, are essentially uncontested. No party to the above-captioned case objected to the use of the 12 months ending September 30, 1990, as adjusted for known and measurable changes occurring up to the end of the hearing, as the test period in this case. The Commission finds this test period for the 12 months ended September 30, 1990, to be appropriate based on the uncontested record evidence.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 11 THROUGH 13

The evidence supporting these findings is contained in the testimony of Company witness Smith and the public witnesses.

Witness Smith testified that the Company has in the past operated with a very lean staff, which limited its ability to perform maintenance on the system in as timely a manner as the Company and this Commission now deem necessary. The Company has now added the additional employees necessary to meet system maintenance needs, comply with federal and state regulatory requirements, and meet the needs associated with the growth of the system.

The Public witnesses appearing in this docket offered no testimony concerning any deficiencies in the Company's natural gas service, rather they testified in support of the Company's proposed rate structure.

In Docket No. G-3, Sub 157, the Commission issued an Order in a show cause proceeding on March 28, 1991, accepting the Company's Settlement Proposal which provided timetables for the replacement of certain mains and the cathodic protection of existing unprotected coated steel and high pressure bare steel mains.

Based on the evidence, the Commission believes that as long as Pennsylvania and Southern complies with the Settlement Proposal in Docket No. G-3, Sub 157, the Company is providing adequate service to its North Carolina retail customers.

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 14

The evidence for this finding is contained in the testimony and exhibits of Company witness Smith and Public Staff witness Davis. As a general proposition, the evidence relating to the Company's adjusted test period operating expenses, revenues under present rates, revenues under proposed rates, current return on rate base, and appropriate allowed return on rate base are uncontested. To a considerable extent, the testimony and exhibits submitted by the Company and the Public Staff were shaped by the Settlement Proposal entered into between the Commission Staff, Pennsylvania and Southern, and the Public Staff on February 22, 1991. In that Settlement Proposal, the Commission Staff, the Company, and the Public Staff agreed that "the Company's next general rate increase application . . . will reflect the following disallowances and other adjustments:

(a) Extraordinary expenses of $18,368 will be excluded from test year expenses in addition to the $91,213 of extraordinary maintenance expenses the Company initially proposed to eliminate;

(b) Twenty-five percent (25%) of the $117,998 spent on cathodic protection and of the $54,296 spent on atmospheric corrosion control during the test year ended September 30, 1990, will be excluded from test year expenses. These amounts are $29,500 and $13,574, respectively, for a total of $43,074.

(c) Capital expenditures of $32,472, which relate to areas cited as violations, will be excluded from rate base;

(d) A capital structure consisting of 53% long-term debt and 47% common equity will be proposed.

(e) An embedded cost of debt of 9.77% and a return of 12.55% on common equity will be requested.

(f) The $70,908 cost of the Henkels and McCoy, Inc.'s report will be amortized over six (6) years beginning in fiscal year 1990, with the unamortized portion being excluded from rate base.

The Company's application, prefiled testimony, and exhibits incorporated the ratemaking provisions of the Settlement Proposal. After the Company filed its prefiled testimony and exhibits, the Public Staff investigated its revenue requirement request. On May 30, 1991, the Company filed an amended Exhibit No. 7, which altered its proposed natural gas sales volumes, adjusted operating expenses, adjusted revenues under proposed rates, and allowed rate of return on rate base in response to certain adjustments recommended by the Public Staff's Accounting and Natural Gas Divisions. This amendment lowered Pennsylvania and Southern's requested increase from $370,052 to $369,851. No party filed any accounting or cost of capital testimony which in any way conflicted with the Company's amended testimony and exhibits concerning the revenue requirement issue.

While the Settlement Proposal contains a proposed resolution of certain potential issues concerning the Company's allowed revenue requirement, neither its existence nor its prior submission to the Commission exempt this body from compliance with the procedures required by G.S. 62-133. Instead, as the Commission concluded in its May 28, 1991, Order Accepting Settlement, the Commission's approval of the Settlement Proposal did not "bind the Commission as to any ratemaking issue in the pending general rate case" and was "without prejudice to the right of any non-settling party in the general rate case to challenge the ratemaking provisions of the settlement in the rate case forum." The Commission afforded the Attorney General and CUCA an opportunity to challenge the ratemaking provisions of the Settlement Proposal and gave the Attorney General, CUCA, and the Public Staff an opportunity to contest the other revenue requirement proposals set forth in the Company's amended testimony and exhibits. At the conclusion of the hearing, the Company's evidence concerning the proper revenue requirement to be established in this proceeding remained uncontested by evidence elicited on either direct or cross-examination.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 15 THROUGH 18

The evidence supporting these findings is found in the Company's application, in Company witness Carl's testimony and exhibits, in Public Staff witness Davis' testimony and exhibits, and in the record as a whole.

In prefiled testimony and exhibits, witnesses Carl and Davis testified to different pro forma gas sales and transportation volume levels. Prior to hearing, the Company accepted the Public Staff's level of sales and transportation volumes and amended its application. The difference in the level of sales and transportation volumes was attributable to the growth factor calculation made by the Company. Upon review, the Company agreed with the Public Staff's calculation and agreed that the appropriate level of sales and transportation volumes should be 2,796,586 dekatherms. Applying the Company's approved rates effective November 1, 1990, to this level of sales and transportation volumes will produce revenues of $14,095,743. No other evidence on the appropriate level of sales and transportation volumes was presented.

The Company and the Public Staff also agreed that the appropriate level of miscellaneous revenues for the test period was $9,162. Combining the miscellaneous revenues and sales revenues results in the parties' recommendation that $14,104,905 is the appropriate level of revenues under present rates for the test period.

Based upon the evidence, the Commission finds that the appropriate sales and transportation volumes for use in this proceeding are 2,796,586 dekatherms, which reflects the exclusion of Company use and lost and unaccounted-for volumes. Further, the Commission concludes that the appropriate level of operating revenues under present rates is $14,104,905.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 19 THROUGH 24

The evidence for these findings is contained in the Company's amended application and the testimony and exhibits of Company witnesses Carl and Smith, as revised at the hearing.

The Company's amended application, which incorporated the Public Staff's adjustments, proposed $13,486,971 as the representative level of operating revenue deductions. This amount excludes $152,655 of test year maintenance expense pursuant to the stipulations contained in Docket No. G-3, Sub 157. No other evidence concerning the appropriate level of operating revenue deductions was presented.

Based upon the evidence, the Commission finds that the uncontested level of operating revenue deductions for use in setting rates in this proceeding is $13,486,971, as shown in the following chart:

Item	Amount
Cost of purchased gas	$ 9,780,085
Operating and maintenance expense	2,658,926
Depreciation	301,750
General taxes	630,799
State income taxes	23,944
Federal income taxes	91,467
Operating revenue deductions	$13,486,971

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 25 THROUGH 26

Net operating income for return is the result of subtracting total operating revenue deductions from total operating revenue. The evidence on both of these components of net operating income for return is set forth above. The Commission concludes that the appropriate pro forma level of net operating income for return under present rates is $617,934.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 27 THROUGH 35

The evidence supporting these findings is contained in the Company's amended application and the testimony and exhibits of Company witnesses Carl and Smith, as revised at the hearing.

The original cost rate base proposed by the Company is $7,556,606, after excluding $32,472 of plant in service pursuant to the Settlement Proposal in Docket No. G-3, Sub 157. No evidence to the contrary was presented.

The Commission, after considering all of the evidence, finds that the unchallenged original cost rate base for use in setting rates in this proceeding is $7,556,606 as shown in the following chart:

Item	Amount
Gas utility plant in service	$10,892,074
Accumulated depreciation	(3,399,449)
Net plant in service	7,492,625
Allowance for working capital	956,755
Accumulated deferred income taxes	(762,301)
Deferred pension liability	(127,180)
Pre-1972 JDITC	(3,293)
Original cost rate base	$ 7,556,606

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 36 THROUGH 41

The evidence supporting these findings is contained in the Company's amended application and the testimony and exhibits of Company witnesses Carl and Smith, as revised at the hearing.

Pursuant to the stipulations in Docket No. G-3, Sub 157, the Company proposed a capital structure consisting of 47% common equity and 53% long-term debt. The requested rate of return on common equity was 12.55% and the requested embedded cost of long-term debt was 9.77%. An 11.08% overall return on investment in rate base is produced by the application of these numbers.

The Commission finds that the uncontested capital structure of 47% common equity and 53% long-term debt, a rate of return on common equity of 12.55% and an embedded cost of 9.77% for long-term debt are reasonable and appropriate for ratemaking purposes in this proceeding. These returns will balance the interest of the ratepayers and investors and meet the test set forth in G.S.62-133(b)(4):"...(to) enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors."

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 42

Based on the rate base, operating revenues, operating revenue deductions, and rates of return previously determined and set forth in this Order, the Commission finds that the Company should be allowed to increase its annual gross revenues by $369,851. This increase has been determined to be consistent with the requirements of G.S. 62-133. With this increase, the Company will have the opportunity to earn the 12.55% return on common equity which the Commission finds to be fair and reasonable.

The following schedules summarize the gross revenues and rate of return the Company should have a reasonable opportunity to achieve based on the increase approved herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions heretofore and hereinafter found reasonable by the Commission.

SCHEDULE I
PENNSYLVANIA AND SOUTHERN GAS COMPANY
(North Carolina Gas Service)
DOCKET NO. G-3, SUB 167
STATEMENT OF NET OPERATING INCOME FOR RETURN
For the Test Year Ended September 30, 1990

Item	Present Rates	Approved Increase	Approved Rates
Operating Revenues:			
Natural gas sales	$14,095,743	$369,851	$14,465,594
Miscellaneous revenue	9,162		9,162
Total operating revenues	14,104,905	369,851	14,474,756
Operating Revenue Deductions:			
Cost of purchased gas	9,780,085		9,780,085
O & M expense	2,658,926	592	2,659,518
Depreciation	301,750		301,750
General taxes	630,799	12,333	643,132
State income taxes	23,944	24,985	48,929
Federal income taxes	91,467	112,860	204,327
Total operating revenue deductions	13,486,971	150,770	13,637,741
Net operating income for return	$ 617,934	$219,081	$ 837,015

SCHEDULE II
PENNSYLVANIA AND SOUTHERN GAS COMPANY
(North Carolina Gas Service)
DOCKET NO. G-3, SUB 167
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Test Year Ended September 30, 1990

Item	Present Rates	Approved Rates
Gas utility plant in service	$10,892,074	$10,892,074
Accumulated depreciation	(3,399,449)	(3,399,449)
Net plant in service	7,492,625	7,492,625
Allowance for working capital	956,755	956,755
Accumulated deferred income taxes	(762,301)	(762,301)
Deferred pension liability	(127,180)	(127,180)
Pre-1972 JDITC	(3,293)	(3,293)
Original cost rate base	$ 7,556,606	$ 7,556,606
Rate of return	8.18%	11.08%

SCHEDULE III
PENNSYLVANIA AND SOUTHERN GAS COMPANY
(North Carolina Gas Service)
DOCKET NO. G-3, SUB 167
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Test Year Ended September 30, 1990

Type of Capital	Original Cost Rate Base	Ratio %	Embedded Cost/Return %	Net Operating Income
		Present Rates		
Long-term debt	$4,005,001	53.00%	9.77%	$391,289
Common equity	$3,551,605	47.00%	6.38%	$226,645
Total	$7,556,606	100.00%		$617,934
		Approved Rates		
Long-term debt	$4,005,001	53.00%	9.77%	$391,289
Common equity	$3,551,605	47.00%	12.55%	$445,726
Total	$7,556,606	100.00%		$837,015

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 43

The evidence supporting this finding on the fixed gas costs true-up is contained in the testimony and exhibits of Company witnesses Carl and Smith and Public staff witness Davis. Witness Carl testified that there should be a matching of revenues and gas costs to allow for the proper functioning of the true-up. Witness Smith also testified that he believed the true-up of fixed gas costs to be an appropriate regulatory adjustment.

Public Staff witness Davis testified in favor of the continuance of the true-up of fixed gas costs as established in a Purchased Gas Adjustment (PGA) filing in Docket No. G-3, Sub 163. By Commission Order dated July 3, 1990, in Docket No. G-3, Sub 163, the Company was authorized an annual true-up of fixed charges as billed by Transco with the actual amounts collected from Pennsylvania and Southern's customers based on actual volumes sold and transported for the same period. The annual true-up will allow the Company to recover 100%, no more or less, of its fixed gas costs from customers on an annual basis.

Both the Company, in its amended application, and the Public Staff are in agreement on the true-up of fixed gas costs.

Davis Exhibit C and the Company's amended cost of gas schedule show the appropriate level of fixed gas costs to be trued-up to be $2,163,341 for purposes of this case. Any subsequent change in this amount due to changes in the Company's supplier of natural gas costs will be made a part of the Company's annual on-going true-up.

Based upon the evidence, the Commission believes that it is reasonable to allow the Company to continue its fixed gas costs true-up in this proceeding.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 44 THROUGH 55

The evidence supporting these findings is contained in the testimony and exhibits of Company witness Carl and Public Staff witness Davis.

The Company and the Public Staff each prefiled a rate design based on their recommended revenue levels. Even though the Company and the Public Staff agreed on all of the other adjustments, rate design remained an issue.

The company provides natural gas sales and transportation service to several different types of customers. The Company's customer mix is 87.3% residential, 12.5% commercial, 0.1% firm industrial, and 0.1% interruptible industrial. The Company makes approximately 28.4% of its sales (including transportation volumes) to residential customers, 19.1% to commercial customers, 13.6% to firm industrial customers, and 38.9% to interruptible industrial customers.

At the present time, the Company provides natural gas service to residential and multiple dwelling consumers for any household purpose under Rate Schedule No. 101; to any commercial customer or school under Rate Schedule No. 102; to all industrial consumers that use gas for process, feedstock and plant protection of less than 50 dekatherms per day with no alternate fuel capability under Rate Schedule No. 201; to all industrial consumers that use gas for process, feedstock and plant protection between 50 and 300 dekatherms per day with no alternate fuel capability under Rate Schedule No. 205; to all industrial consumers that use gas for process, feedstock and plant protection between 300 and 3,000 dekatherms per day with no alternate fuel capability under Rate Schedule No. 206; to all industrial customers not covered by any other rate schedule who would be placed in priorities three through five under Rate Schedule No. 208; and to all customers using natural gas for boiler fuel purposes only using over 300 dekatherms per day during any 24 hour period so long as the customer agrees to use his daily requirements when available and permits gas served to be curtailed or completely interrupted upon two hours' notice by the Company under Rate Schedule No. 600.

The Company's existing Rate Schedule Nos. 201, 205, 206, and 208 all apply to industrial customers using gas for process, feed stock, and plant protection purposes. The only differences between customers eligible for service under Rate Schedule Nos. 201, 205, 206, and 208, are their daily natural gas consumption and their priorities under the Commission's former priority rules.

In its prefiled testimony and exhibits, the Company proposed a restructured rate design providing natural gas sales service to single family residential units and governmental housing projects under Rate Schedule No. 101; to commercial (including churches regularly used for religious worship) and to industrial users whose maximum usage during any month during the 24 month period ended on the 30th day of June preceding the date in question was not more than 1,500 dekatherms under Rate Schedule No. 102; to all customers whose usage during any month during the 24 month period ended on the 30th day of June preceding the date in question was in excess of 1,500 dekatherms under Rate Schedule No. 104; and to all customers whose usage during any month during the 24 month period ended on the 30th day of June preceding the date in question was in excess of 1,500 dekatherms subject to interruption or curtailment upon 1 hour's notice under Rate Schedule No. 105. Schedule No. 105 customers would be required to have alternate fuel capability.

Under the Company's proposal, residential customers would continue to receive service under Rate Schedule No. 101; customers previously served under Rate Schedule Nos. 102 and 201 would receive service under Rate Schedule No. 102; customers previously served under Rate Schedule Nos. 205, 206, and 208 would receive service under Rate Schedule No. 104; and customers previously served under Rate Schedule Nos. 206, 208, and 600 could receive service under Rate Schedule No. 105 by meeting the required criteria. The fundamental changes involved in the Company's proposed rate restructuring are the merger of Rate Schedule Nos. 102 and 201 into Rate Schedule No. 102, the consolidation of Rate Schedule Nos. 205, 206, and 208 into Rate Schedule No. 104; and the availability of Rate Schedule No. 105.

Witness Carl testified that the Company's analysis of the sales volumes, the revenue requirements, and the return provided by the customers presently receiving service pursuant to Rate Schedule Nos. 205, 206 and 208 indicates that the required unit rates for these classes of customers should be very close; as a result, the Company proposed that service for this group should be provided according to a single rate schedule, Large General Service. Similarly, witness Davis testified that he agreed with the Company's proposal to consolidate present Rate Schedule Nos. 205, 206, and 208 into proposed Rate Schedule No. 104 because the customers in these rate schedules have similar characteristics in manner of use, time of use, and consumption patterns. According to witness Davis, the Commission's decision to suspend the priority classification procedures and to authorize curtailment of service by margin contribution means that segregation by priority and by rate schedule is not as essential as it once was. The evidence supporting the Company's proposed redesign of its nonresidential rate schedules was not contested by any other party.

The undisputed evidence establishes that the only difference between customers currently served under Rate Schedule No. 102 and those served under Rate Schedule No. 201 is the nature of the business in which those customers are engaged. The record does not contain any evidence tending to show that the cost of serving commercial and small industrial customers would vary because of the nature of the businesses in which those customers are engaged. As a result, the Company's proposal to combine existing Rate Schedule Nos. 102 and 201 should be approved.

Similarly, the testimony of witnesses Carl and Davis indicates no appreciable differences in the cost of serving customers who presently purchase gas under Rate Schedule Nos. 205, 206 and 208. In view of the similarities in the cost of providing service to customers under existing Rate Schedule Nos. 205, 206 and 208, the Commission will approve the proposed consolidation of these three rate schedules.

Finally, the availability of new Rate Schedule No. 105 to some customers currently served under Rate Schedule Nos. 206, 208 and 600 does not substantially change the Company's present rate structure. The only practical effect of this proposal is to remove the provision in existing Rate Schedule No. 600 limiting the availability of that schedule to customers using natural gas for boiler fuel purposes. The proposed new Rate Schedule No. 105 should be approved.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 56 THROUGH 58

The evidence for these findings is contained in the testimony and exhibits of Company witness Carl and Public Staff witness Davis.

The Company's existing rate schedules do not contain seasonal differentials; instead, each rate utilizes a uniform per dekatherm charge applicable year-round. The Company proposed to include summer/winter differentials in all of its proposed rate schedules. In support of this proposal, witness Carl testified that this type of a rate differential is used by other North Carolina distribution companies and properly matches revenues received with costs incurred, specifically storage related costs. Although witness Davis did not specifically address this issue in his testimony, the rates proposed by the Public Staff which are included in witness Davis' exhibits reflect summer/winter differentials.

The Commission recognizes, as a matter of common knowledge, that the demands placed upon the Company's system are greatest in the winter and that the cost of providing natural gas service is highest at time of peak demand. For that reason, the Commission has previously approved summer/winter differentials in the rates charged by the state's other local distribution companies. In view of the prevalence of summer/winter differentials in North Carolina natural gas rates, the consistency of summer/winter differentials with fundamental cost of service principles, and the lack of any evidence suggesting that the Company's proposed summer/winter differentials are in any way inappropriate, the Commission concludes that the Company's proposal to include summer/winter differentials in its North Carolina retail rates are appropriate and should be approved.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 59 THROUGH 62

The evidence for these findings is contained in the testimony and exhibits of Company witness Carl and Public Staff witness Davis.

Witness Carl testified that the Company had not prepared an independent cost-of-service study, and that it had reviewed the cost-of-service studies done for the last rate case by the Public Staff and had made some judgments from those studies in preparing its proposed rates. Witness Davis testified that he had prepared studies under the United and Seaboard Methodologies; that the Seaboard Method assigns 50% of fixed costs on the basis of peak demand and the other 50% on the basis of annual sales; that the cost-of-service studies using the Seaboard methodology and a one-day peak demand allocation factor were more representative of the present market situation than the other cost-of-service studies which he had prepared; and that he had included two Seaboard cost-of-service studies in his exhibits incorporating the Public Staff's adjustments and proposed revenue level. On cross-examination, CUCA questioned witness Davis concerning the proper manner in which to assign fixed gas costs among customer classes and introduced the complete cost-of-service studies summarized in witness Davis' exhibits into evidence.

The Company obtains a gas supply for resale through interstate pipeline capacity on the Transco interstate pipeline system. In return for various monetary fees, Transco delivers natural gas volumes to the Company at certain times and under certain conditions. Generally speaking, there are two basic types of gas delivery contracts or fixed gas costs between the Company and Transco: year-round transportation services and peaking or storage services. For the most part, the Public Staff's Seaboard cost-of-service studies assigned the first category of fixed gas costs using a "peak and average" allocation factor which assigned 50% of these year-round service costs on the basis of annual sales and 50% on the basis of class contributions to the Company's one-day system peak. The studies assigned the second category of fixed gas costs on the basis of either annualized winter sales or class contributions to the Company's one-day system peak.

In order to obtain year-round natural gas supplies, the Company pays an Interim Service Fee (hereinafter "an ISF charge"); a firm transportation charge (hereinafter "a FT charge"); and a Sales Differential Differed Rate charge (hereinafter "a SDDR charge"). All of these charges constitute payment for capacity in Transco's pipeline to deliver gas to Pennsylvania and Southern's customers in the form of firm transportation rates or year-round firm services.

Similarly, the Company purchases various peaking and storage services from Transco for use at times of peak demand. For example, the Company pays PS-2 Demand charges to obtain a peak shaving service; pays GSS withdrawal, demand, capacity, and injection charges to obtain general storage service used at peak times; WSS withdrawal and capacity charges in order to obtain a storage service used for peak day service; and LGA delivery, demand, and capacity charges to obtain a "propane service" or a peaking type service intended to meet the system peak.

Finally, the Company receives Demand Charge Credits from Transco. According to witness Davis, these Demand Charge Credits result from Order 500 entered by the Federal Energy Regulatory Commission. They relate to some changes in demand costs that were to come back to customers and were accumulated under the various demand charges discussed elsewhere in the record. In other words, these Demand Charge Credits relate to either the firm transportation type charges or to PS-2, GSS, WSS, or LGA.

CUCA contended in its proposed order that none of the fixed gas costs vary on the basis of annual sales. It cited the payment of ISF, SDDR, and FT fees in order to obtain firm rather than interruptible pipeline service. It also cited the pricing of such services based on their availability at the time of system peak. CUCA further cited other fixed gas costs associated with GSS, WSS, LGA, and P-2 Demand services having similar characteristics. It contended that all of the fixed gas costs should be allocated on the basis of class contributions to the Company's one-day system peak rather than on the basis of annual seasonal sales volumes.

The Commission is of the opinion that the fixed gas costs should be allocated in the manner proposed by the Public Staff for purposes of this proceeding. Such allocation would be consistent with the allocations adopted in previous proceedings by the Commission, and would be a prudent approach in this proceeding.

Except for the controversy over "fixed gas costs," no party questioned the manner in which the Public Staff assigned revenues, rate base, and operating expenses to customer classes. In view of the lack of controversy among the parties to this proceeding over the manner in which witness Davis assigned the Company's remaining revenues, operating expenses, and investments among customer classes, the Commission accepts the remainder of the Public Staff's Seaboard cost-of-service studies. As a result, the Commission concludes that revenues, rate base costs, operating expenses, and other cost of service components should be assigned to customer classes on the basis of the cost-of-service studies proposed by witness Davis.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 63 THROUGH 65

The evidence supporting these findings is contained in the testimony and exhibits of Company witness Carl, Public Staff witness Davis, and CUCA witnesses Dorris, Dillon, Moore and Waynick.

The principal issue in this proceeding was the extent to which the Company's North Carolina retail rates should be adjusted to eliminate class rate of return disparities. The rate design, as proposed by Company Witness Carl, would result in the following increases and decreases over present rates:

Rate Schedule	Customer Class	Percent Increase/(Decrease)
101	Residential	16.8%
102	Small Commercial	9.8%
104	Firm Industrial	(3.7)%
105	Interruptible Industrial	(14.6)%

Witness Carl testified that the Company's proposed rate structure represented a continuation of its efforts to have the rates reflect commercial reality and to have the different classes of customers bear their fair share of the cost of providing service. He said that although Pennsylvania and Southern did not perform a cost-of-service study in preparing its proposed rate structure, it reviewed the cost of service study done for the last rate case by the Public Staff and made some judgments from that study. In addition, the Company made a careful study of rates charged by other gas utilities throughout the state to different classes of customers and considered competitive factors, who created the demand, and security of the supply,the quantity of use, the value of service to the customer, the frequency of interruption of interruptible customers, and availability of alternate fuel sources. Witness Carl said that under the Company's proposed rate structure, the Company's residential customers would still have the lowest rates in the State while shouldering a fair part of the load; the same would be true of commercial and firm industrial customers; and the reduction in interruptible rates makes those base rates the lowest rates in the state and improves the competitive position of those interruptible customers.

Witness Davis testified that a declining block rate design, as proposed for Rate Schedule 105, was appropriate for interruptible industrial customers. He stated that he had evaluated the bill frequency and determined that two blocks were sufficient for the summer and winter seasons. He said that the first block should encompass consumption between 0 and 15,000 dts and the second block would be for all consumption over 15,000 dts.

The rate design proposed by the Public Staff would have the following effect on Pennsylvania and Southern's customers over present rates:

Rate Schedule	Customer Class	Percent Increase/(Decrease)
101	Residential	10.01%
102	Small Commercial	9.53%
104	Firm Industrial	(2.90)%
105	Interruptible Industrial	(7.28)%

Witness Davis testified that cost of service studies were just one aspect in the consideration of rate design. He indicated that cost of service is subjective and judgmental at best, and that he did not depend solely on them for the magnitude of rate increases or decreases necessary to align rates. Witness Davis said that these studies are a useful guide, but cannot objectively determine the class returns. According to witness Davis, rate design is an assimilation of various considerations, including historical rate design principles, alternative fuel capabilities, the encouragement of growth, comparison of rates among other gas utilities in the State, comparisons of other companies in other states, and factors approved by this Commission in other cases. Witness Davis indicated that he performed cost studies under the United and Seaboard Methodologies for a total of eight studies with different and wide-ranging results.

Witness Davis also indicated that the studies do not reflect the actual returns for industrial customers, but tend to overstate them. The studies incorporate the revenue level for industrial customers priced at the existing tariff rates and therefore do not reflect negotiated rates. Although opposing the Company's proposed rate structure, witness Davis agreed with the Company that residential rates should be increased more than the average increase requested in this case and that firm and interruptible industrial rates under the Company's proposed Rate Schedule Nos. 104 and 105 ought to be decreased.

Four representatives from manufacturing firms located in the Pennsylvania and Southern service territory testified in support of the Company's proposed rate structure.

Douglas W. Dorris, a purchasing agent employed by Fieldcrest Cannon, testified that Fieldcrest Cannon is a major textile manufacturer of bed, bath and carpet items for the world market; that its Eden area operations employ approximately 2,600 people; that, during the past five years, Fieldcrest Cannon consumed approximately 2,500,000 dekatherms of natural gas purchased from the Company; that Fieldcrest Cannon preferred to use natural gas in its boilers because it's a cleaner fuel; that, in order for Fieldcrest Cannon to continue to take advantage of natural gas, it must be sold at a competitive price in relation to the alternate fuels; that the Company currently has the highest rates for natural gas when compared against other local distribution companies providing service to Fieldcrest Cannon; and that Fieldcrest Cannon supported the Company's proposed rate structure.

Joe Dillon, an engineer with Macfield, Inc., testified that Macfield packages dye filaments and spun yarns for home furnishing, automotive, narrow tapes, clothing garments, labels, and other businesses; that MacField had two dye houses located in Rockingham County served by Pennsylvania and Southern employing about 1,400 people; that MacField used natural gas to produce steam for heating the dye baths, scour process and dying of yarns and incurred a monthly gas bill in excess of $100,000; that MacField hoped that it could grow in this business if it could maintain a competitive cost over alternate materials; that it wished to continue to burn natural gas due to the cleanliness of gas versus oil to reduce the pollution to the atmosphere and maintenance of equipment; and that it was one of the best customers that Pennsylvania and Southern can have as it consumes gas on a 24 hour per day, seven days per week basis.

Vernon Moore, an employee of Pine Hall Brick Company, testified that Pine Hall was a manufacturer of face brick in the state of North Carolina; that it took service from Pennsylvania and Southern's North Carolina Gas Division; that Pine Hall presently consumed only about 1,500 dekatherms per month; that, in late 1978, Pine Hall probably consumed 2,000 dekatherms per day; that it currently used sawdust as its principal fuel source; that Pine Hall's Madison, North Carolina, manufacturing facility employed about 260 employees with a payroll last year of $5.5 million and produced about 125 million brick; that Pine Hall planned to construct a new manufacturing facility which had to burn natural gas; and that, in order to remain competitive, Pine Hall would have to be able to obtain gas at prices similar to those charged by other local distribution companies to its competitors.

Jim Waynick, director of personnel with Equity Group, testified that Equity Group had a food manufacturing plant in Reidsville, North Carolina, which used about $20,000 worth of natural gas a month; that it was in constant competition with other facilities, one in Nashville, Tennessee, and one in Gadsen, Alabama; that it was just barely competitive at the present time; and that it must stay competitive to keep this business and keep people employed here in Reidsville, North Carolina.

The Commission is of the opinion that the cost-of-service studies presented by the Public Staff are certainly an important and relevant guide or factor to be weighed in designing rates in this proceeding. Nevertheless, it must be kept in mind that the cost-of-service studies presented in this docket are not objective in nature, but rather reflect the preparer's judgment as to how to fairly allocate common costs among customer classes, as well as being based on numerous assumptions. The studies presented show varying rates of return depending on the methodology followed and the assumptions involved. There are several other factors or ratemaking principles in addition to cost of service to consider in designing rates for natural gas utilities, as has been discussed at length by the Commission in other general rate case orders. Among these are: (1) the value of service to the customer; (2) the type and priority of service received by the customer and, if the service is interruptible, the frequency of interruptions; (3) the quantity of use; (4) the time of use; (5) the manner of service; (6) the competitive conditions in the market place related to the acquisition of new customers; (7) the historic rate differentials between the various classes of customers; (8) the revenue stability to the utility; and (9) the economic and political factors which are inherent in the ratemaking process. The Commission believes that the rate design proposed by the Public Staff is appropriate for use in this proceeding and will reflect the relative risk to the Company of serving each class of customers, while giving appropriate consideration and weight to each of the relevant factors noted above and by the parties to this proceeding.

Rates of return for customers who have no alternate fuels readily available, such as residential customers, should not be directly compared to rates of return for those customers who do in fact have alternate fuels, such as boiler fuel customers. Rates of return for customers who cannot negotiate their rates with the Company or who cannot obtain supplies of cheaper gas under transportation rates should not be compared directly to rates of return for those customers who can and indeed do negotiate their rates. The services provided in either case are not directly comparable, so the respective rates of return are not directly comparable either. The risk to the Applicant of maintaining its margin on service to the high-priority market, which includes residential customers, is significantly less than the risk to the Company of maintaining its margins on service to large industrial customers. Such risk is further magnified when one looks at the Applicant's customer sales mix, which consists of 28.5% residential, 19.1% commercial, 13.6% firm industrial, and 38.9% interruptible industrial.

The Commission further notes that the industrial rates, approved for use herein, have all been decreased for the various industrial rate schedules ranging from a decrease of 2.90% to a decrease of 7.28%, while the residential rates have been increased 10.01% and the commercial rates have been increased 9.8%. This represents an attempt to adjust rates of return for each rate class closer to the overall rate of return and to reflect the relative risk to the Company of serving each class of customers. The Commission finds that the rate design approved in this proceeding does not unreasonably discriminate against the industrial customers, after weighing and balancing all of the relevant factors discussed herein, and that the rate design is just and reasonable.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS NOS. 66 THROUGH 71

The evidence for these findings is contained in the testimony and evidence of Company witness Carl and Public Staff witness Davis.

At the present time, Pennsylvania and Southern transports customer-owned gas under Rate Schedule T, which provides that interruptible transportation service may be offered to a large commercial or industrial customer who is presently connected to the Company's system, who has qualified for service on Rate Schedule No. 205, 206, 208 or 600, who has obtained an independent supply of natural gas, and who has made arrangements to have the gas delivered by Transco to one of the Company's existing delivery points. Under existing Rate Schedule T, the Company may refuse transportation service where it determines that it does not have natural gas delivery capacity in excess of the requirements of its other existing customers, where the requested transportation service would require an uneconomic enlargement or extension of the Company's facilities, or where the provision of the requested transportation service might unreasonably increase the average cost of gas purchased by the Company for sales to other customers. In order to obtain the transportation of customer-owned gas under existing rates, the customer must pay the Company for all gas transported under this rate schedule at a predetermined rate established prior to delivery not to exceed the appropriate tariff rate.

In this proceeding, the Company has proposed Rate Schedule No. 106, under which transportation service is available for any customer connected to the Company's system who has obtained an independent supply of natural gas, who has arranged to have this supply delivered to one of the Company's existing delivery points, and who qualifies for the purchase of gas under Rate Schedule No. 104 or 105. Under proposed Rate Schedule No. 106, the Company is required to attempt to deliver gas previously transported to the Company by connecting pipelines for the customer's account in accordance with a service agreement between the Company and the customer. However, the Company reserves the right to suspend transportation service on any day, when in the Company's sole opinion, its operating conditions are such that suspension of service is necessary. Under the Company's proposed transportation schedule, the rate to be charged for gas service may vary but may not exceed the maximum of "certain charges" specified in the rate schedule.

Both existing Rate Schedule T and proposed Rate Schedule No. 106 are "full margin" transportation rates. Under Rate Schedule No. 106, the transportation of customer-owned gas is priced at the applicable sales rate less the commodity cost of gas, relevant gross receipt taxes, and any temporary increments or decrements. Both witness Carl and Witness Davis testified that their respective organizations favored the continuation of "full margin" transportation rates. On cross-examination by CUCA, witness Davis stated that the full margins that both the Public Staff and the Company have proposed in this case include fixed gas costs. CUCA opposed the inclusion of fixed gas costs as a part of the margin in transportation rates.

In other proceedings, the Commission has approved "full margin" transportation rates based upon contentions that the use of another sort of transportation rate would require sales rate customers to subsidize transportation customers, that the services provided by local distribution companies to transportation customers and sales rate customers were identical, that sales rate and transportation gas pass through the local distribution company's delivery system in the same manner, that local distribution companies perform the same billing services for both sales rate and transportation customers, that customers use sales rate and transportation gas for the same purposes, that the consumption characteristics of sales rate and transportation customers are similar, and that the Company is required to obtain a gas supply for transportation customers.

The Commission concludes that the proposed full margin transportation rates are appropriate for use in this proceeding, consistent with the Commission's philosophy and recent past decisions involving Piedmont Natural Gas Company, Inc., Public Service Company of North Carolina, Inc., and North Carolina Natural Gas Corporation. A full margin rate is defined as the regular sales rate at which the customer would normally purchase gas less gross receipts tax, less any temporary increments or decrements, less the benchmark cost of gas. This residual rate is then increased to include gross receipts tax.

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION NO. 72

Based on the operating revenues and rate designs previously determined herein, the Commission finds that the rates set forth in Appendix A attached hereto are just and reasonable and will generate the appropriate level of revenues affording the Company an opportunity to achieve the approved overall rate of return of 11.08%.

IT IS, THEREFORE, ORDERED as follows:

1. That Pennsylvania and Southern Gas Company (North Carolina Gas Service Division), be, and hereby is, authorized to increase its rates and charges in order to produce $369,851 in additional annual gross revenues, effective upon the date of this Order.

2. That Pennsylvania and Southern Gas Company (North Carolina Gas Service Division) be, and hereby is, required to file tariff sheets not later than 10 days from the date of this Order, reflecting the rates approved herein, as shown on Appendix A, in order to achieve the increase approved in Ordering Paragraph No. 1.

3. That Pennsylvania and Southern Gas Company (North Carolina Gas Service Division) be, and hereby is, required to notify its customers of the rates approved herein by appropriate notice in the next billing cycle following the date of this Order. Such Notice to Customers shall be submitted to the Commission within 10 days of the date of this Order for approval prior to issuance.

ISSUED BY ORDER OF THE COMMISSION.
This the 25th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A

PENNSYLVANIA AND SOUTHERN GAS COMPANY
(NORTH CAROLINA GAS SERVICE)
DOCKET NO. G-3, SUB 167
COMMISSION APPROVED RATES

RATE SCHEDULE	DESCRIPTION	SEASON *		BILLS	FACILITIES CHARGE ($/MONTH)	SALES VOLUME (DTS)	APPROVED RATE ($/DT)	TOTAL REVENUE ($)
101	RESIDENTIAL SERVICE			115,134	$6.00			$690,806
		WINTER				602,062	$6.0005	3,612,692
		SUMMER				192,127	$5.7505	1,104,832
	TOTAL RATE 101							5,408,330
102	SMALL GENERAL SERVICE			16,442	$10.00			164,420
		WINTER				353,665	5.5005	1,945,345
		SUMMER				180,271	5.2505	946,519
	TOTAL RATE 102							3,056,284
103	GAS LIGHTS			39	$7.77			303
	TOTAL RATE 103							
104	LARGE GENERAL SERVICE			108	$200.00			21,600
		WINTER				197,882	4.5505	900,468
		SUMMER				182,581	4.3005	785,195
	TOTAL RATE 104							1,707,263
105	INTERRUPTIBLE SERVICE			192	$200.00			38,400
		WINTER -	FIRST 15,000			198,370	4.2005	833,258
			OVER 15,000			191,272	4.1005	784,318
		SUMMER	FIRST 15,000			352,274	3.9005	1,374,054
			OVER 15,000			346,082	3.6505	1,263,385
	TOTAL RATE 105							4,293,415
	TOTALS			131,915		2,796,586		14,465,595
	MISC. REVENUES							9,162
	TOTAL REVENUES							$14,474,757

NOTE
* - WINTER - NOVEMBER THROUGH MARCH
SUMMER - APRIL THROUGH OCTOBER

DOCKET NO. G-5, SUB 280

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Public Service Company of North Carolina, Inc., For an Adjustment of Its Rates and Charges	))))	ORDER GRANTING PARTIAL RATE INCREASE

HEARD IN: Conference Room No. 203, 2nd Floor, City Office Building, Corner of South Center Street and East Front Street, Statesville, North Carolina, on Tuesday, August 20, 1991, at 7:00 p.m.

Council Chambers, City Hall, Corner of South Street and Franklin Boulevard, Gastonia, North Carolina, on Wednesday, August 21, 1991, at 7:00 p.m.

Superior Court Room, 5th Floor, Buncombe County Courthouse, Courthouse Plaza, 189 College Street, Asheville, North Carolina, on Thursday, August 22, 1991, at 7:00 p.m.

Commission Hearing Room No. 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, September 3, 1991, at 7:00 p.m.

Commission Hearing Room No. 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, September 4, 1991, at 9:00 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding; and Commissioners Charles H. Hughes and Allyson K. Duncan

APPEARANCES:

For the Applicant:

F. Kent Burns and James M. Day, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

For the Public Staff-North Carolina Utilities Commission:

Paul L. Lassiter, Staff Attorney, Robert B. Cauthen, Jr., Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the Attorney General:

Lorinzo L. Joyner, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602-0629
For: The Using and Consuming Public

For the City of Durham:

William I. Thornton, Jr., City Attorney, Gayle Moses, Assistant City Attorney, 101 City Hall Plaza, Durham, North Carolina 27701

For the Carolina Utilities Customers Association, Inc.:

Sam J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon, & Ervin, P.A., One Northsquare, Post Office Drawer 1269, Morganton, North Carolina 28655

BY THE COMMISSION: On April 1, 1991, Public Service Company of North Carolina, Inc. ("Public Service" or the "Company"), filed an application with the Commission (NCUC or Commission) in Docket No. G-5, Sub 280, seeking authority to adjust and increase its rates and charges for natural gas service to its retail customers.

On April 24, 1991, the Commission issued an Order suspending the proposed rates, setting the matter for investigation and hearings to be held in Asheville, Gastonia, Statesville and Raleigh.

On April 18, 1991, the Attorney General filed Notice of Intervention pursuant to G.S. 62-20 on behalf of the using and consuming public.

On April 23, 1991, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene. On May 10, 1991, the Commission issued an Order allowing CUCA's intervention.

On May 13, 1991, the City of Durham filed a Petition to Intervene. On May 15, 1991, the Commission issued an Order allowing the City of Durham's intervention.

Public hearings were held for the specific purpose of receiving testimony from public witnesses as follows:

Statesville:	No public witnesses appeared.
Asheville:	No public witnesses appeared.
Gastonia:	William Martin and Richard Earl Thomas, each appeared and offered testimony.
Raleigh:	Edmund Klemmer appeared and offered testimony.

The case in chief came on for hearing on September 4, 1991.

Public Service offered the testimony and exhibits of the following witnesses: Charles E. Zeigler, Jr., President and Chief Operating Officer; Franklin H. Yoho, Vice President of Gas Supply and Transportation; Jerry W. Richardson, Senior Vice President - Engineering; C. Marshall Dickey, Executive Vice President - Operations/Services; Robert D. Voigt, Senior Vice President - Controller and Assistant Treasurer; and Robert S. Jackson, Senior Vice President of Stone & Webster Management Consultants.

The Public Staff presented the testimony and exhibits of the following witnesses: Danny P. Evans, Financial Analyst with the Economic Research Division; Jeffrey L. Davis, Public Utilities Engineer with the Natural Gas Division; and Kris Au Hinton, Staff Accountant with the Accounting Division.

Neither the City of Durham, the Attorney General, nor CUCA offered any witnesses.

In addition, at the hearing, Public Service introduced into evidence (identified as Public Service Company Exhibits 1 and 2 and later amended by Public Service Company Exhibit 3) a "Stipulation of Public Service Company of North Carolina, Inc. and the Public Staff" (the Stipulation) which reflected Public Service's and the Public Staff's agreement on all issues before the Commission in this docket. The City of Durham and the Attorney General, although not formal parties to the Stipulation, announced at the hearing that neither would object to the Stipulation. CUCA also did not formally join in the Stipulation, as they objected to certain portions of the Stipulation; however, CUCA did announce at the hearing that they would not contest the revenue requirement portions of the Stipulation. CUCA did contest the issues of rate design, the full margin transportation rate concept, and certain provisions of the Rider D tariff.

On September 26, 1991, the Company and the Public Staff filed a Motion to file a late exhibit to make minor clarifications/corrections to certain provisions of Rider D and the base rates as adjusted for the change to a $2.50 per dekatherm benchmark cost of gas, respectively. These clarifications/corrections are shown on Public Service Company Exhibit 4 which was attached to the Motion. The Motion was granted on October 2, 1991.

Following the hearings, the parties submitted proposed orders and briefs.

Based upon the foregoing, the verified application, the testimony and exhibits received into evidence at the hearings, the proposed orders submitted by the parties and the entire record in this proceeding, the Commission makes the following:

FINDINGS OF FACT

1. Public Service is a corporation organized and existing under the laws of North Carolina with its principal place of business located in Gastonia, North Carolina.

2. Public Service is engaged in the business of transporting, distributing, and selling natural gas in a franchise area which consists of all or parts of 26 counties in western and central North Carolina.

3. Public Service is a public utility as defined in G.S. 62-3(23) and is subject to the jurisdiction of this Commission.

4. Public Service is lawfully before this Commission based upon its application for a general increase in its rates pursuant to G.S. 62-133.

5. The Company's application, testimony, exhibits, N.C.U.C. Form G-1, affidavits of publication, and published hearing notices are in compliance with the provisions of the Public Utilities Act and the Rules and Regulations of the Commission.

6. The appropriate test period for use in this proceeding is the twelve months ended December 31, 1990, adjusted for certain known and measurable changes occurring after the end of the test period and before the conclusion of the hearing as permitted by G.S. 62-133(c).

7. The level of service rendered by Public Service to its customers during the test period was good.

8. In its initial application, Public Service sought to increase its North Carolina retail rates by $8,882,727 and to roll-in $16,978,928 in fixed gas costs into base rates.

9. Prior to the commencement of technical hearings in the above-captioned proceeding, Public Service and the Public Staff entered into a Stipulation in which the parties to that document agreed that "Public Service is entitled to an increase in revenues of $5,299,074 ...and entitled to roll $12,843,728 of deferred gas costs into its base rates charged to its customers." The other parties to the above-captioned proceeding were given an opportunity to present testimony and cross-examine various witnesses concerning Public Service's revenue requirement; however, neither the Attorney General, the City of Durham, nor CUCA objected to the revenue requirement embodied in the Stipulation between Public Service and the Public Staff.

10. G.S. 62-133(b)(2) requires the Commission to estimate Public Service's revenues under present rates.

11. In order to estimate Public Service's revenues under present rates, the Commission must determine an appropriate level of adjusted sales and transportation volumes and ascertain the level of revenues, including miscellaneous revenues, which the Company would earn under present rates based upon those adjusted sales and transportation volumes.

12. Public Service sold and transported 492,096,476 therms under its various sales and transportation rates during the test period.

13. Public Service's test period data should be adjusted to reflect any abnormality having a probable impact on the Company's revenues.

14. Public Service's test period sales and transportation volumes should be adjusted to account for negotiated sales, weather, customer growth, the

transfer of existing customers from one rate schedule to another, and the cessation of operations by certain existing customers.

15. The appropriate level of pro forma sales and transportation volumes is 499,917,569 therms.

16. The appropriate level of unaccounted for volumes is 10,167,330 therms.

17. The appropriate level of pro forma operating revenues under present rates is $265,737,476 consisting of revenues from the sale and transportation of gas of $257,538,260 and other operating revenues of $8,199,216 and assuming a commodity cost of gas of $3.50 per dekatherm.

18. G.S. 62-133(b)(3) requires the Commission to ascertain the Company's reasonable operating expenses, including depreciation.

19. The Company's appropriate pro forma level of cost of gas expense under present rates for the purpose of this proceeding is $177,838,000 assuming a $3.50 per dekatherm commodity cost of gas.

20. The appropriate pro forma level of operation and maintenance expense under present rates for the purpose of this proceeding is $41,199,576.

21. The appropriate pro forma level of depreciation expense under present rates for the purpose of this proceeding is $12,483,108.

22. The appropriate pro forma level of general taxes under present rates for the purpose of this proceeding is $13,127,259.

23. The appropriate pro forma level of state income taxes under present rates for the purpose of this proceeding is $660,816.

24. The appropriate pro forma level of federal income taxes under present rates for the purpose of this proceeding is $2,588,928.

25. The appropriate level of investment tax credit amortization under present rates for the purpose of this proceeding is $467,071.

26. The appropriate pro forma level of operating revenue deductions under present rates for the purpose of this proceeding is $247,430,616, consisting of $177,838,000 in cost of gas expense, $41,199,576 in operation and maintenance expense, $12,483,108 in depreciation expense, $13,127,259 in general taxes, $660,816 in state income taxes, $2,588,928 in federal income taxes, and investment tax credit amortization in the amount of $467,071.

27. Net operating income for return under present rates is determined by subtracting total operating revenue deductions under present rates of $247,430,616 from total operating revenues under present rates of $265,737,476.

28. The appropriate level of net operating income for return under present rates for the purpose of this proceeding is $18,306,860.

29. G.S. 62-133(b)(1) requires the Commission to ascertain the reasonable cost of the utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing service to the public.

30. The appropriate level of utility plant in service for use in this proceeding is $403,782,939.

31. The appropriate level of accumulated depreciation for use in this proceeding is $112,504,021.

32. The appropriate allowance for working capital for use in this proceeding is $6,636,945.

33. The appropriate level of accumulated deferred income taxes for use in this proceeding is $37,198,361.

34. The Company's reasonable rate base for use in this proceeding is $260,717,502 consisting of $403,782,939 in utility plant and $6,636,945 in working capital reduced by $112,504,021 in accumulated depreciation and $37,198,361 in accumulated deferred income taxes.

35. G.S. 62-133(b)(4) requires the Commission to determine a fair rate of return on the Company's rate base.

36. The overall return on Public Service's rate base under present rates is 7.02%, which is calculated by dividing the net operating income for return under present rates of $18,306,860 by the Company's rate base of $260,717,502.

37. The appropriate capital structure for use in this proceeding consists of 48.98% long-term debt, 2.62% short-term debt, .86% preferred stock, and 47.54% common equity.

38. The appropriate cost of long-term debt for use in this proceeding is 9.58%.

39. The appropriate cost of short-term debt for use in this proceeding is 8.5%.

40. The appropriate cost of preferred stock for use in this proceeding is 6.03%.

41. Using the capital structure and cost rates found appropriate above, the Company's return on common equity under present rates is 4.32%. This 4.32% return on common equity under present rates is mathematically determined by dividing net operating income under present rates remaining after the payment of interest on long-term debt, interest on short-term debt, and preferred stock dividends by the common equity portion of the rate base.

42. In its prefiled testimony and exhibits, Public Service requested approval of a 13.75% return on common equity. In its prefiled testimony and exhibits, the Public Staff recommended approval of a 12.37% return on common equity for Public Service. As a part of the Stipulation, Public Service and the Public Staff stipulated that the appropriate return on common equity was 12.9%.

43. The 12.9% return on common equity recommended by Public Service and the Public Staff results from a compromise between them. Neither the Attorney General, the City of Durham, nor CUCA recommended approval of a different return on common equity. Thus, the appropriate return on common equity for use in this proceeding is 12.9%.

44. Combining a return on common equity of 12.9% with the capital structure and costs of long-term debt, short-term debt, and preferred stock found appropriate herein results in an overall return of 11.10% to be applied to the Company's rate base.

45. The 11.10% overall return on rate base found to be appropriate by the Commission will balance the interests of ratepayers and investors and will enable Public Service by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors.

46. The Commission cannot guarantee that the Company will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if we could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency.

47. The amounts set forth in the "Increase Approved" and "After Increase Approved" columns of Schedules I and II and under "Approved Rates" in Schedule III hereinafter set forth in the evidence and conclusions below are matters of mathematical computation which have been agreed to by the Company and the Public Staff in the Stipulation.

48. The amounts set forth in the columns "Benchmark Cost of Gas Change" and "After Change In Benchmark Cost of Gas" in Schedule I reflect the change from a $3.50 per dekatherm benchmark cost of gas to a $2.50 per dekatherm benchmark cost of gas and are also matters of mathematical computation which have been agreed to by the Company and the Public Staff in the Stipulation.

49. Additional revenues of $18,142,807 will provide the Company with the opportunity to earn the returns found appropriate herein.

50. The Company and the Public Staff stipulated to the use in this proceeding of a pro forma cost of gas and initial benchmark cost of gas of $2.50 per dekatherm.

51. The Company can modify its benchmark cost of gas in the manner set forth in its Rider D.

52. The rates stipulated to by the Company and the Public Staff will produce an overall increase of 3.63%.

53. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 4.4% to "residential customers who use natural gas on a year around basis" under Rate Schedule 105.

54. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 12.1% to "residential customers who use natural gas on a seasonal basis" under Rate Schedule 110.

55. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 2.3% to "commercial and small industrial customers who are primarily engaged in the sale of goods or services, manufacturing, schools, institutions and governmental agencies who use natural gas on a year around basis" under Rate Schedule 125.

56. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 15.2% to "commercial and small industrial customers who are primarily engaged in the sale of goods or services, manufacturing, schools, institutions and governmental agencies who use natural gas on a seasonal basis" under Rate Schedule 130.

57. The rates stipulated to by the Company and the Public Staff will produce a decrease of approximately (3.6%) to "large commercial and industrial customers using in excess of 500 therms per day on an annual basis adjusted for curtailment, subject to an adequate supply of natural gas and delivery capability at the location of the customers' facilities" under Rate Schedule 145.

58. The rates stipulated to by the Company and the Public Staff will produce a decrease of approximately (2.7%) to "large commercial and industrial customers using in excess of 500 therms per day on an annual basis adjusted for curtailment . . . who have the installed capability to burn an alternate fuel" under Rate Schedule 150.

59. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 9.9% to " large commercial or industrial customers who are presently connected to the Company's system, have qualified for service on Rate Schedule 145, have obtained an independent supply of natural gas, and have made arrangements to have the gas delivered . . . to one of the Company's existing delivery points" under Rate Schedule 175.

60. The rates stipulated to by the Company and the Public Staff will produce an increase of approximately 25.4% to " large commercial or industrial customers who are presently connected to the Company's system, have qualified for service on Rate Schedule 150, have obtained an independent supply of natural gas, and have made arrangements to have the gas delivered . . . to one of the Company's existing delivery points" under Rate Schedule 180.

61. It is appropriate to consider a number of factors when designing rates, including cost of service, value of service, quantity of natural gas used, the time of use, the manner of use, the equipment which the Company must provide and maintain in order to meet the requirements of its customers, competitive conditions and consumption characteristics. The Stipulation is based upon these factors.

62. Both Public Service and the Public Staff presented cost-of-service studies under existing and proposed rates. No other party prepared a cost-of-service study.

63. Aside from sales and revenue levels, the only material differences between the cost-of-service studies presented by Public Service and the Public Staff related to the treatment of distribution mains and fixed gas costs.

64. CUCA endorsed the Company's cost-of-service study.

65. No cost-of-service study was prepared under the Stipulation.

66. The Stipulation rate design contains some elements of the Company's rate design and some elements of the Public Staff's rate design.

67. The Utilities Commission is not required to approve rates resulting in equalized customer class rates of return.

68. The rendition of service to each of Public Service's customer classes involves varying degrees of risk.

69. The Commission has historically concluded that specific customer classes should not receive rate increases which, in light of all the surrounding facts and circumstances, result in "rate shock."

70. In determining whether a specific class increase results in "rate shock," the Commission considers the utility's historic rate design.

71. Fully equalized returns would place an unreasonable burden on residential customers relative to their historical rates.

72. It is not reasonable to adopt the goal of solely cost-based rates and equalized rates of return among customer classes in this case.

73. Large industrial and commercial customers receiving transportation services under Rate Schedule 180 would see a 25.4% increase in rates under the Stipulation agreed to by the Company and the Public Staff.

74. Because transportation rates exclude the commodity cost of gas, applicable gross receipts taxes and any temporary increments and decrements, percentage changes in transportation rates are calculated on a lower base than for sales rates.

75. The increase in Rate Schedule 180 under the Stipulation does not result in "rate shock."

76. The rates set forth in Stipulation Schedule 2, Column 6 and approved herein are just and reasonable, do not result in any unjust or unreasonable discrimination or preference between or within classes of customers and should be approved.

77. Public Service and the Public Staff have proposed the continuation of full margin transportation rates.

78. The Commission has considered the use of full margin transportation rates on many occasions in the past and has each time determined such rates to be appropriate.

79. The Commission approved full margin transportation rates in the Company's last rate case.

80. There has been no material change in the services rendered by the Company to transportation customers since the Company's last rate case.

81. Under full margin transportation rates, the rate charged by Public Service for the transportation of customer-owned gas consists of the applicable sales rate reduced by the commodity cost of gas, applicable gross receipts taxes, and any temporary increments or decrements.

82. Transportation rates allow customers on Rate Schedules 145 and 150 an opportunity to obtain cheaper gas at the wellhead.

83. Public Service acquires gas for its transportation customers so it can provide them gas when transportation gas supply is not available.

84. The services performed by Public Service are substantially the same whether service is provided under the sales rate or transportation rate.

85. Full margin transportation rates are just and reasonable.

86. Public Service's Rider D is intended to permit the Company to negotiate rates in order to avoid the loss of sales volumes resulting from decreasing alternate fuel costs, to permit the adjustment of natural gas sales rates in light of changing commodity costs, and to "true-up" both commodity and fixed gas costs.

87. No party to this proceding proposed the elimination of Rider D.

88. The revised Rider D proposed by the Company in this case provides that the cost of gas to be recovered includes all costs related to gas supply and capacity. The proposed revised Rider D provides for a 100% true-up of all prudently incurred gas costs.

89. The Commission has initiated proceedings, separate from this general rate case, in Docket G-100, Sub. 58, in order to define "costs" for purposes of G.S. 62-133.4 and in order to provide for implementation of G.S. 62-133.4.

90. Provisional approval of the revised Rider D as proposed by Public Service to include the costs of additional pipeline capacity and storage is made without prejudice to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G.S. 62-133.4.

91. The revised Rider D proposed by the Company and Public Staff in the Stipulation should be approved on a provisional basis, as hereinabove provided, pending implementation of G. S. 62-133.4.

92. In its original prefiled testimony and exhibits, Public Service proposed to increase the facility charges for customers served under Rate Schedule No. 110 from $8.00 per month to $10.00 per month and to increase facility charges for customers served under Rate Schedule No. 130 from $12.00 per month to $15.00.

93. Customers served under Rate Schedules 110 and 130 are seasonal customers and are only on service for a portion of the year. The increases in facilities charges more nearly recover the annual cost of serving Rate Schedule 110 and 130 customers over just the portion of the year when they are using gas.

94. Public Service's request to increase the facility charges for customers served under Rate Schedule Nos. 110 and 130 is just, reasonable, and should be approved for service rendered on and after the effective date of this Order.

95. In its original prefiled testimony and exhibits, Public Service proposed certain modifications to its service regulations, including an increase in its reconnection fees, an increase in its fees for after-hours service, and a requirement that its industrial customers have only one alternate fuel for each delivery.

96. Public Service and the Public Staff agreed to the text of Public Service's service regulations. Except for the issue relating to the necessity that there be only one alternate fuel for each delivery, neither the Attorney General, the City of Durham, nor CUCA contested approval of the service regulations embodied in the Stipulation between Public Service and the Public Staff, including the proposed increases in reconnection and after-hours fees.

97. Public Service and the Public Staff agreed to a provision that in order to purchase gas at negotiated rates under Rate Schedule 160 all equipment supplied on a single account must have the capability to accept curtailment and must have the same type of alternate fuel.

98. The provision requiring the same alternate fuel for each account served under Rate Schedule 160 is necessary to ensure that the negotiated rate program is administered fairly.

99. The amended service regulations embodied in the Stipulation between Public Service and the Public Staff are just, reasonable, and appropriate for use in connection with service rendered on and after the effective date of this Order.

100. The Company's earnings and certain customers' bills vary widely on the basis of weather.

101. Public Service has requested Commission approval of a Weather Normalization Adjustment clause.

102. Public Service benefits from its proposed Weather Normalization Adjustment clause in that it has a more predictable revenue stream and therefore can better plan its business.

103. Public Service's proposed Weather Normalization Adjustment clause will reduce variations in its earnings and rates of return and in customers' bills.

104. Public Service's proposed Weather Normalization Adjustment clause will tend to increase bills during times of warm weather when consumption is low and reduce bills during times of abnormally cold weather when consumption is high.

105. The proposed Weather Normalization Adjustment clause will protect both the Company and its customers from the adverse impact of departures from normal weather.

106. The appropriate customer classes to be included in Public Service's Weather Normalization Adjustment clause for purposes of this proceeding are customers served under Rate Schedule Nos. 105, 110, 125, and 130.

107. Under Public Service's Weather Normalization Adjustment clause, fixed gas costs will be allocated to the various customer classes as stipulated to between Public Service and the Public Staff.

108. The Weather Normalization Adjustment clause stipulated to by Public Service and the Public Staff is fair and reasonable and should be approved for service rendered on and after the effective date of this Order.

109. The level of actual unaccounted for volumes during any given period fluctuates.

110. Any difference in the level of unaccounted for volumes set in a general rate case and those actual volumes results in either a gain or loss to the Company.

111. The Public Staff proposed and Public Service accepted a true-up of unaccounted for volumes.

112. The actual twelve month running unaccounted for volumes at June of each year (the Actual Volumes) shall be compared to the level of the unaccounted for volumes included in Public Service's most recent general rate case Order (the Rate Case Volumes). On or before September 1 of each year, Public Service shall file a report with the Commission reflecting the Actual Volumes for the preceding twelve months ending June 30. The difference, if any, between these Actual Volumes and the Rate Case Volumes shall be multiplied by the appropriate commodity cost of gas. The dollar amount resulting from this calculation shall be refunded to or collected from Public Service's customers, as appropriate, through increments, decrements, or other mechanism ordered by the Commission.

113. As a result of the Tax Reform Act of 1986, the Commission required Public Service to record the net excess deferred tax flowback in an accumulated deferred income taxes (ADIT) true-up account and to gross-up these amounts for income taxes.

114. The $86,358 balance in Public Service's ADIT true-up account as of the end of the test year should be increased by $54,336 to reflect the income tax effects.

115. The total of $140,694 should be placed in the Company's Deferred Gas Cost Account and refunded to ratepayers through a decrement in rates.

116. Transco charges Public Service for gas utilized in moving gas into its General Storage Service and Washington Storage Service facilities.

117. The Company compensates Transco for this gas use through a payment-in-kind transaction. The Company provides gas to Transco to replace gas utilized for storage injections.

118. The cost of this replacement gas should be charged to the gas in storage inventories rather than the cost of gas account.

119. Public Service is not required to change its accounting treatment of non-plant deferred tax items at this time as was initially recommended by the Public Staff.

120. The combination/split of the Company's deferred gas costs accounts be maintained on and after the effective date of this Order as set forth in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 1-6

The evidence supporting these findings of fact is contained in the verified application, the Commission's files and records regarding this proceeding, the Commission Orders scheduling hearings, and the testimony of Company witnesses. These findings of fact are essentially informational and uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NUMBER 7

The evidence supporting this finding is contained in the testimony of Company witnesses Zeigler and Richardson and the public witnesses.

The record contains no indication that Public Service is providing anything other than good natural gas service in its service territory. The testimony and exhibits of Mr. Zeigler, Mr. Yoho, and Mr. Richardson indicate that the Company has experienced significant customer growth, particularly among residential and small commercial customers; that the Company attempted to obtain additional interstate pipeline capacity in order to serve these new customers; and that the Company has made substantial expenditures to enhance and expand its service. The public witnesses presenting testimony in this proceeding offered no testimony concerning any deficiencies in Public Service's service. Based upon the undisputed evidence, the Commission concludes that Public Service is providing good service.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 8-9

The evidence supporting these findings is contained in the application, the Stipulation Of Public Service Company Of North Carolina, Inc., And The Public Staff and in the testimony of other Public Service and Public Staff witnesses, who indicated that their respective organizations assented to the Stipulation and that it superseded their original positions. Among other things, the Stipulation provided the following:

"The Parties acknowledge that this Stipulation resulted from extensive negotiations and compromise. Thus, the agreements reached do not necessarily reflect the respective Parties' beliefs as to the proper treatment or level of the matters recited. Except as needed to carry out the terms of the Commission's order which is based on this Stipulation, the Parties have agreed that none of the positions, treatments, figures, or other matters reflected in this Stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matter in issue."

CUCA objected to portions of the Stipulation; without joining in the Stipulation, neither the Attorney General nor the City of Durham opposed its approval. The Commission accepted the Stipulation in evidence and proceeded with the hearing in order to allow all affected parties an opportunity to be heard. The Commission has considered the Stipulation along with all of the evidence and has weighed its terms in the context of the entire record in order to determine Public Service's rates under the standards required by G.S. 62-133 and other applicable statutes.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 10-17

The evidence in support of these findings is contained in the Company's application, the Stipulation, the testimony of Company witnesses Dickey and Voigt, and the testimony of Public Staff witnesses Davis and Hinton.

In their prefiled testimony and exhibits, witnesses Dickey and Davis testified to different pro forma gas sales and transportation volume levels. Prior to the hearing, the Public Staff and the Company stipulated that the reasonable pro forma level of volumes sold and transported was 499,917,569 therms. This level of pro forma sales and transportation volumes differs from the volumes recommended by both Mr. Dickey and Mr. Davis. No other evidence concerning the appropriate level of sales and transportation volumes was presented and neither the Attorney General, the City of Durham, nor CUCA objected to the level of the volumes set forth in the Stipulation. Public Service and the Public Staff stipulated that the appropriate level of pro forma gas sales and transportation revenues under present rates was $257,538,260; that the appropriate level of pro forma other operating revenues under present rates was $8,199,216; and that Public Service's appropriate level of pro forma total operating revenues under existing rates were $265,767,476. Based upon the evidence and the Stipulation between Public Service and the Public Staff, the Commission concludes that the appropriate level of pro forma sales and transportation volumes for use in this proceeding is 499,917,569 therms and that the pro forma level of total operating revenues under present rates is $265,737,476.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 18-28

The evidence for these findings is contained in the Stipulation. The prefiled testimony and exhibits submitted by Public Service and the Public Staff reflect different levels of operating revenue deductions for use in this proceeding. Prior to the hearing, Public Service and the Public Staff stipulated that the appropriate pro forma level of operating revenue deductions under present rates for the purpose of this proceeding is $247,430,616, consisting of $177,838,000 in cost of gas expense, $41,199,576 in operation and maintenance expense, $12,483,108 in depreciation expense, $13,127,259 in general taxes, $660,816 in state income taxes, and $2,588,928 in federal income taxes, and investment tax credit amortization in the amount of $467,071. After deducting the $247,430,616 in operating revenue deductions from the $265,737,476 in total operating revenues under present rates, the Company and the Public Staff stipulated to a net operating income for return under present rates of $18,306,860. Neither the Attorney General, the City of Durham, nor CUCA objected to the stipulated level of operating revenue deductions or net operating income for return. Based upon the evidence in the record and the Stipulation between Public Service and the Public Staff, the Commission concludes that the appropriate pro forma level of operating revenue deductions under present rates is $247,430,616 and that the level of operating income for return under present rates is $18,306,860, as set forth in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 29-34

The evidence for these findings is contained in the Stipulation. In their original prefiled testimony and exhibits, Public Service and the Public Staff recommended that the Commission approve differing levels of investment in utility property used and useful in rendering natural gas sales and transportation service in the Company's service territory. Prior to the hearing, Public Service and the Public Staff stipulated that the appropriate levels of the Company's rate base for use in this proceeding are $403,782,939 in utility plant investment, $112,504,021 in accumulated depreciation, a $6,636,945 allowance for working capital, and $37,198,361 in accumulated deferred income taxes, resulting in a total rate base of $260,717,502. Neither the Attorney General, the City of Durham, nor CUCA objected to the approval of the stipulated rate base. As a result, the Commission concludes that the reasonable rate base for use in this proceeding is $260,717,502, as set forth in the Stipulation.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 35-46

The evidence supporting these findings is contained in the testimony of Public Service witnesses Voigt and Jackson and Public Staff witnesses Evans and Hinton and in the Stipulation.

In the Company's prefiled testimony and exhibits, it recommended the approval of a capital structure consisting of 51.11% long-term debt, 0.86% short-term debt, 0.93% preferred stock, and 47.10% common equity. The Company developed its requested capital structure by utilizing the average capital structure of Public Service for the test year ended December 31, 1990. In determining the appropriate common equity amount, Public Service subtracted $258,000 relating to certain Transco refunds. The short-term debt component of the Company's requested capital structure is based upon the ratio of average stored gas inventory to stored gas inventory and construction work in progress applied to the average month-ending short-term debt balances from December, 1989, through December, 1990. The Public Staff proposed a capital structure consisting of 49.02% long-term debt, 3.24% short-term debt, 0.85% preferred stock, and 46.89% common equity utilizing an updated version of the methodology recommended by the Company. Prior to the hearing, Public Service and the Public Staff stipulated that the appropriate capital structure for use in this proceeding consisted of 47.54% common equity, 48.98% long-term debt, 0.86% preferred stock, and 2.62% short-term debt. Neither the Attorney General, the City of Durham, nor CUCA objected to the approval of this proposed capital structure. Accordingly, the stipulated capital structure is reasonable and is appropriate for use in this proceeding.

In determining the cost rates to be applied to the long-term debt, short-term debt, and preferred stock components of Public Service's capital structure, the Commission has traditionally used actual, embedded debt and preferred costs. Public Service and the Public Staff initially recommended similar costs for the long-term debt, short-term debt, and preferred stock components of the capital structure before stipulating that the appropriate long-term debt, preferred stock and short-term debt costs for use in this proceeding were 9.58%, 6.03% and 8.50%, respectively. Neither the Attorney General, the City of Durham, nor CUCA opposed the stipulated long-term debt, short-term debt, and preferred stock rates. Based upon the evidentiary record and the Stipulation between Public Service and the Public Staff, the Commission concludes that the appropriate cost of long-term debt is 9.58%, that the appropriate cost of preferred stock is 6.03%, and that the appropriate cost of short-term debt is 8.5%. The use of these long-term debt, short-term debt, and preferred stock cost rates in the capital structure which the Commission has previously found to be appropriate indicates that Public Service's return on common equity under present rates is 7.02%.

The prefiled testimony and exhibits of the Company recommend that the cost of common equity is 13.75% while the Public Staff recommended a 12.37% return on common equity. Prior to the hearing, Public Service and the Public Staff stipulated that the appropriate return on common equity for use in this proceeding was 12.9%. Neither the Attorney General, the City of Durham, nor CUCA objected to the stipulated return on common equity. The determination of the appropriate return on equity is one of the most significant decisions which the Commission is required to make in any general rate case. In the final analysis, the determination of a fair rate of return on rate base, including a return on common equity, depends upon the informed and impartial judgment of the Commission. G.S. 62-133(b)(4) requires that the allowed return on rate base be sufficient to "enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers and the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors." The Supreme Court of North Carolina concluded that the history of G.S. 62-133(b) "supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States." State ex rel. Utilities Commission v. Duke Power Company, 285 N.C. 277, 206 S.E. 2d 269 (1974). The return on common equity recommended by Public Service and the Public Staff in the Stipulation is slightly below the midpoint of the range supported by the prefiled testimony and exhibits of Public Service witness Jackson and Public Staff witness Evans. Upon consideration of the entire record in this proceeding, the Commission believes that a 12.9% return on common equity is reasonable and appropriate for use in this proceeding. As a result, the Commission concludes that the return on common equity appropriate for use in this proceeding is 12.9% and that 11.10% is the overall return on rate base which should be allowed pursuant to G.S. 62-133(b)(4).

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 47-49

The following schedules summarize the gross revenues and rate of return the Company should have a reasonable opportunity to achieve based upon the increase approved herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions heretofore and hereinafter found reasonable by the Commission. The items making up the various components of those schedules under "Present Rates" is supported by the evidence, findings and conclusions set forth above. The amounts set forth in the "Increase Approved" and "After Increase Approved" columns of Schedules I and II and in columns under "Approved Rates" in Schedule III are matters of mathematical computation which have been agreed to by the Company and the Public Staff in the Stipulation. The amounts set forth in the columns "Benchmark Cost of Gas Change" and "After Change In Benchmark Cost of Gas" in Schedule I reflect the change from a $3.50 benchmark cost of gas to a $2.50 benchmark cost of gas and are also matters of mathematical computation which have been agreed to by the Company and the Public Staff in the Stipulation.

Schedule I
PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.
DOCKET NO. G-5, SUB 280
STATEMENT OF NET OPERATING INCOME FOR RETURN
For the Test Year Ended December 31, 1990

Item	Present Rates	Increase Approved	After Increase Approved	Benchmark Cost of Gas Change	After Change In Benchmark Cost of Gas
Operating Revenues:					
Sale and transportation of gas	$257,538,260	$16,336,286	$273,874,546	$(43,264,171)	$230,610,375
Other operating revenue	8,199,216	1,806,521	10,005,737		10,005,737
Total operating revenue	265,737,476	18,142,807	283,880,283	(43,264,171)	240,616,112
Operating Revenue Deductions:					
Cost of gas	177,838,000		177,838,000	(41,871,065)	135,966,935
Operation and maintenance	41,199,576	83,460	41,283,036		41,283,036
Depreciation	12,483,108		12,483,108		12,483,108
General taxes	13,127,259	597,764	13,725,023	(1,393,106)	12,331,917
State income taxes	660,816	1,353,273	2,014,089		2,014,089
Federal income taxes	2,588,928	5,476,825	8,065,753		8,065,753
Amortization of ITC	(467,071)		(467,071)		(467,071)
Total operating revenue deductions	247,430,616	7,511,322	254,941,938	(43,264,171)	211,677,767
Net operating income for return	$ 18,306,860	$10,631,485	$ 28,938,345		$ 28,938,345

SCHEDULE II
PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.
DOCKET NO. G-5, SUB 280
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Test Year Ended December 31, 1990

	Present Rates	After Approved Rates
Gas utility plant in service	$403,782,939	$403,782,939
Accumulated depreciation	(112,504,021)	(112,504,021)
Net plant in service	291,278,918	291,278,918
Allowance for working capital	6,636,945	6,636,945
Accumulated deferred taxes	(37,198,361)	(37,198,361)
Original cost rate base	$260,717,502	$260,717,502
Rate of return	7.02%	11.10%

SCHEDULE III
PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.
DOCKET NO. G-5, SUB 280
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Test Year Ended December 31, 1990

Type of Capital	Original Cost Rate Base	Ratio%	Embedded Cost/Return %	Net Operating Income
		Present Rates		
Long-term debt	$127,699,432	48.98%	9.58%	$12,233,606
Short-term debt	6,830,799	2.62	8.50	580,618
Preferred stock	2,242,171	0.86	6.03	135,203
Common equity	123,945,100	47.54	4.32	5,357,433
Total	$260,717,502	100.00%		$18,306,860
		Approved Rates		
Long-term debt	$127,699,432	48.98%	9.58%	$12,233,606
Short-term debt	6,830,799	2.62	8.50	580,618
Preferred stock	2,242,171	0.86	6.03	135,203
Common equity	123,945,100	47.54	12.90	15,988,918
Total	$260,717,502	100.00%		$28,938,345

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 50-51

The evidence in support of these findings is contained in the testimony and exhibits of Public Service witnesses Dickey, Voigt, and Yoho and Public Staff witness Davis and the Stipulation.

All parties to this proceeding initially determined Public Service's revenue requirement by utilizing a $3.50 per dekatherm commodity cost of gas. With deregulation of wellhead natural gas prices and Transco's transformation into an "open access" interstate pipeline, the commodity cost of natural gas has fallen dramatically in recent years. During this period, Public Service's actual commodity cost of gas has fallen below $3.50 per dekatherm. In order to reflect a more representative commodity cost of gas in the Company's base rates, the Public Staff proposed that the benchmark commodity cost of gas be lowered from $3.50 per dekatherm to $2.50 per dekatherm. In the Stipulation between Public Service and the Public Staff, the parties adopted the Public Staff's recommendation. Neither the Attorney General, the City of Durham, nor CUCA objected to the inclusion of a $2.50 benchmark commodity cost of gas in the Company's base rates. Based upon the evidentiary record and the Stipulation, the Commission concludes that it is appropriate to include a benchmark commodity cost of gas in Public Service's base rates which more accurately reflects the actual commodity cost of gas and that the $2.50 per dekatherm commodity cost of gas mentioned in the Stipulation is a reasonable method for reaching that goal.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 52-60

The evidence for these findings is contained in Public Service witness Dickey's Late-filed Exhibit 1.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 61-76

The evidence for these findings is contained in the exhibits and testimony of Public Service witnesses Dickey and Zeigler and Public Staff witness Davis and in the Stipulation.

Company witness Dickey prepared a cost-of-service study the results of which are shown in Dickey Exhibit 3, page 1. He stated that a cost-of-service study is useful as a tool to estimate the return on each class of service to help balance rate design. He added that a cost-of-service study is a somewhat subjective comparison of rates since many judgments of the preparer are reflected in the outcome. Witness Dickey stated that he used the same methodology used in the last several rate cases by the Company. He stated that direct assignment was used where possible and where costs could not be directly assigned, they were allocated based on statistical studies done by the Company. Under the cost-of-service study presented by the Company for use in this proceeding, Public Service would earn the following customer class rates of return under existing rates:

Total Company	9.42%
Rate Schedule No. 105/120	3.45%
Rate Schedule No. 110	1.43%
Rate Schedule No. 125	11.63%
Rate Schedule No. 130	-1.13%
Rate Schedule No. 145	32.67%
Rate Schedule No. 150	59.12%

Under the cost-of-service study presented by the Company for use in this proceeding, Public Service would earn the following customer class rates of return under proposed rates:

Total Company	11.49%
Rate Schedule No. 105/120	6.84%
Rate Schedule No. 110	7.07%
Rate Schedule No. 125	11.73%
Rate Schedule No. 130	8.89%
Rate Schedule No. 145	25.16%
Rate Schedule No. 150	47.91%

Witness Dickey also testified that the Company designs rates to recover the revenue requirement allowed by the Commission and considers the following principles: (1) cost of service, (2) value of service or competitive conditions existing in the marketplace, (3) historical rate structure and relationship between the rates, (4) consumption characteristics of the different classes of customers, (5) future prospects of maintaining sales levels to the various classes of customers, (6) their need for conservation, (7) National and State policies, and (8) ease of administration. He mentioned as additional factors the customer's ability to negotiate rates, quantity of gas used, time of use, manner of use and the equipment the Company must install and maintain. Company witness Dickey also testified that the proposed rates would increase the rate of return for the residential class of customers. This was done because utility sales are based on average embedded costs rather than incremental costs. A large portion of the increase in utility plant since the last rate case was to serve new residential customers. Since incremental costs exceed embedded costs, new residential customers have contributed a disproportionate amount to increased costs. In fairness to other customer classes, residential rates should more nearly provide the overall rate of return. Witness Dickey also pointed out that if a feasibility test is used to determine whether an extension of service is economically sound, residential rates closer to the overall rate of return would increase the likelihood of a utility being able to meet new requests for service from this class of customers.

On cross examination, Company witness Dickey testified that he had not performed a cost-of-service study on the stipulated rates. He stated that the Stipulation rate design contained some elements of the Company's rate design and some elements of Public Staff's rate design.

Public Service witness Zeigler testified on cross examination that the existence of a weather normalization adjustment does not eliminate all of the risk associated with weather sensitive customer classes. Public Service witness Dickey testified on cross examination that residential and small commercial loads tend to be more heat sensitive than industrial loads.

Public Staff witness Davis also presented cost-of-service studies. These studies show various rates of return for the different customer classes. Witness Davis prepared a cost-of-service study based on the Seaboard methodology. The Seaboard method assigns 50% of fixed costs on the basis of peak demand and the other 50% on the basis of annual sales. Witness Davis testified that the differences between his cost-of-service study and the one prepared by the Company can be attributed mainly to differences in the allocations of the fixed cost of gas and the cost of mains under utility plant. He also stated that cost-of-service studies are subjective and judgmental at best and that they are useful as a guide but cannot objectively determine the returns paid by each customer class. Under the cost-of-service study presented by the Public Staff for use in this proceeding, Public Service would earn the following customer class rates of return under existing rates:

Total Company	7.20%
Rate Schedule No. 105/120	5.39%
Rate Schedule No. 110	3.45%
Rate Schedule No. 125	11.94%
Rate Schedule No. 130	1.42%
Rate Schedule No. 145	12.47%
Rate Schedule No. 150	9.24%

Under the cost-of-service study presented by the Public Staff for use in this proceeding, Public Service would earn the following customer class rates of return under proposed rates:

Total Company	10.78%
Rate Schedule No. 105/120	8.45%
Rate Schedule No. 110	7.00%
Rate Schedule No. 125	16.22%
Rate Schedule No. 130	5.12%
Rate Schedule No. 145	15.96%
Rate Schedule No. 150	14.15%

Public Staff witness Davis also testified that industrial customers who can switch to alternate fuels present more risk to the Company. If alternate fuels prices fall enough, these customers can leave the system. Industrial customers with alternate fuel capability also negotiate their filed tariff rates and thereby avoid paying the full rate of return. He also testified that there are other important factors that must be utilized for rate design, including (1) quantity of use, (2) value of service, (3) manner of use, (4) alternate fuel capability and price and (5) historical rate design. On cross examination, witness Davis testified that unlike some industrial customers which can switch to alternate fuels quickly, residential customers have to make a considerable investment in order to switch to an alternate fuel. He testified that rate shock results when rates are increased to the point where a class of customers cannot bear the increase and begin looking for an alternative. He agreed that the concept of rate shock should apply to any type of rate. However, he pointed out that percentage changes in transportation rates are not equivalent to percentage changes in sales rates. Under the full margin concept, both sales rates and transportation rates would receive the same absolute increase, but the percent change in the transportation and sales rates would not be equivalent. He also testified that the ability of a customer class to switch to an alternate fuel is also a factor in considering rate shock.

CUCA's arguments on cost of service in its proposed order centered on the treatment of distribution mains and fixed gas costs. CUCA advocated the use of Public Service's methodology. Public Services's cost-of-service study, for various reasons, assigned more fixed costs to peak day users.

The Commission has consistently maintained and held that it would not be appropriate to design natural gas rates solely on the basis of cost-of-service studies. The Supreme Court of North Carolina has also noted that factors other than cost-of-service should be considered in setting utility rates. In Utilities Commission v. N.C. Textile Manufacturers Assoc., 313 N.C. 215, 222, 238 S.E.2d 264, 269 (1985), the Court held:

> "In determining whether rate differences constitute unreasonable discrimination, a number of factors should be considered: '(1) quantity of use, (2) time of use, (3) manner of service, and (4) costs of rendering the two services.' Utilities Comm. v. Oil Co., 302 N.C. 14, 23, 273 S.E.2d 232, 238 (1980). Other factors to be considered include 'competitive conditions, consumption characteristics of the several classes and the value of service to each class, which is indicated to some extent by the cost of alternate fuels available.' Utilities Comm. v. City of Durham, 282 N.C. 308, 314-15, 193 S.E.2d 95, 100 (1972)."

The Supreme Court examined this matter again in State ex rel. Utilities Commission v. Carolina Utility Customers Association, 323 N.C. 238, 372 S.E.2d 692 (1988). In that case, CUCA and other parties challenged the Commission's decision in a North Carolina Natural Gas Corporation (NCNG) general rate case that the differences in rates of return among NCNG's various customer classes were not unreasonably discriminatory nor unjust and unreasonable. The Court found that the Commission had made adequate findings and conclusions and that the Commission had drawn "legitimate distinctions" which justify maintaining large industrial rates of return at a higher level than residential, commercial, and small industrial rates of return. The Court held, "While an assessment of the Commission's Order based simply on the cost-of-service evidence might suggest the adopted rates are unreasonably discriminatory, the Commission's analysis of the non-cost factors permitted in our case law is sufficient to justify the Commission's decision." *Id* at 252. The Supreme Court examined this matter most recently in Utilities Commission v. Carolina Utility Customers Association, 328 N.C. 37, 399 S.E. 2d 98 (1991). In this case, the Court once again held that the Commission did not have to establish rates based solely on cost-of-service considerations.

The Commission notes that the two cost-of-service studies that were prepared differed, with CUCA endorsing the Company's approach. Cost-of-service studies reflect a good deal of subjective judgment. The Company and the Public Staff signed a Stipulation. Testimony shows that a specific cost-of-service study was not stipulated. The Stipulation included elements of both the Public Staff's cost-of-service study and the Company's cost-of-service study.

The Commission concludes that because of the subjectivity involved it is not necessary to endorse any single cost-of-service study and that the Stipulation rate design adequately considered cost-of-service factors.

The Stipulation reveals that the stipulated rate design contains essentially all of the common elements of the Company's and the Public Staff's proposals, with adjustments made to some of the rate levels. Common elements include the same rate classes, the use of summer/winter differentials, the use of the same facilities charges and the use of the same declining blocks in the industrial rates.

CUCA objected to the rate levels themselves, although they offered no evidence as to what they contend is the appropriate level of rates. CUCA has again argued that greater reliance should be placed on the cost-of-service studies. CUCA also suggests moving in three steps over this and the next two rate cases towards equalized rates of return. With regard to the consideration of alternate fuel prices in ratemaking, CUCA argues that the use of alternate fuel prices as a "floor" below which natural gas rates should not be allowed to drop exposes certain customer classes to the monopoly power of the local distribution company. CUCA contends that the 25.37% increase in rates for transportation customers served under Rate Schedule 180 in the Stipulation constitutes rate shock.

The Commission concludes that it is appropriate to consider a number of factors when designing rates, including cost of service, value of service, quantity of natural gas used, the time of use, the manner of use, the equipment which the Company must provide and maintain in order to meet the requirements of its customers, competitive conditions and consumption characteristics.

With regard to equalized rates of return, return is a function of risk. Witnesses for the Public Staff and Company testified that different customer classes presented different risk profiles. Although no witness attempted to quantify the risk associated with the different customer classes, Public Staff witness Davis testified that industrial customers with alternate fuel capabilities presented more risk to the Company than other customer classes. Rates of return among customer classes, as shown on cost-of-service studies, are not directly comparable. Large industrial customers do not always pay the rates approved, as assumed in cost-of-service studies. Public Service has the right to, and does, negotiate rates for these customers in order to meet alternative fuel prices. This ability to negotiate lower rates gives these industrial customers a bargaining power unavailable to residential and small general service customers and increases the risk to the Company. This justifies a higher rate of return relative to residential and small general service customers. CUCA's argument that only 2,500 dekatherms were sold at negotiated prices during the test period does not convince the Commission that the risk associated with fuel switching is slight. It demonstrates that the relationship between gas prices and alternate fuel prices was favorable to gas during the test period. It in no way speaks to the risks faced in the future. Rates of return are not comparable for another reason. Fuel-switchable customers pose greater financial risk because they can leave the system, causing Public Service substantial loss of sales. The degree of this risk is a function of alternative fuel prices. Therefore, it is important that the Company be able to negotiate gas prices below the tariff rate when alternative fuel prices are low, in order to lessen the risk of losing customers. It is equally important that the tariff rate be set so as to result in a return being paid by these customers when alternative fuel prices are high that will compensate the Company for the higher risks of these customers. To the extent the relative risks among customer classes has changed, the risk facing the Company from weather sensitive customer classes will be reduced -- but not eliminated -- by the proposed Weather Normalization Adjustment clause.

The effect of equalized returns, even if achieved over several rate cases, would be traumatic on Rate Schedule 105 because these customers, unlike many fuel-switchable customers, cannot easily switch fuels. At the time Rate Schedule 105 customers bought their heating plants, their gas rates looked relatively attractive compared to how they would look under equalized returns, and the long-established expectations of these customers should be taken into consideration.

The Commission is not required to approve rates resulting in equalized customer class rates of return. State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 328 N.C. 37, 39 S.E. 2d 98 (1991); State ex rel. Utilities Commission v. Carolina Utility Customers Association, Inc., 323 N.C. 238, 372 S.E. 2d 692 (1988); State ex rel. Utilities Commission v. North Carolina Textile Manufacturers Association, 313 N.C. 215, 328 S.E. 2d 264 (1985). The Commission concludes that it is not appropriate to adopt equalized rates of return.

Furthermore, the Commission does not agree with CUCA's contention that alternate fuel prices should not be used as a floor. CUCA's member companies have been the prime beneficiaries of the use of value of service as a consideration in ratemaking. Both negotiated rates and transportation rates grew out of the Commission's recognition of the need to consider value of service and competitive conditions in ratemaking. It would be unjust and unreasonable to emphasize value of service and competitive conditions when alternate fuel prices are relatively cheap compared to gas and then return to cost-of-service when alternate fuel prices are relatively high.

The Commission concludes that the 25.37% increase for Rate Schedule 180 under the Stipulation does not constitute rate shock. Public Staff witness Davis' argument that percentage changes in transportation rates do not equate to percentage changes in sales rates is convincing. The total cost of natural gas delivered to the transportation customer includes the price of the gas itself. A 25% change in the transportation component of the delivered cost will not evoke rate shock.

The Commission concludes that the rate design reflected in the Stipulation is just and reasonable, is based on factors recited by the Supreme Court as appropriate, and does not unduly discriminate between the different rate classes and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 77-85

The evidence for these findings is contained in the exhibits and testimony of Public Service witnesses Dickey and Public Staff witness Davis and the Stipulation.

On cross examination, Public Service witness Dickey affirmed that growth in the number of residential customers is significantly larger than the other classes and that residential customers have "the most increase in peak per increase in annual consumption". He also stated that the full margin on which transportation rates are developed includes everything except the commodity cost of gas and related gross receipts tax changes. Third Party Gas Demand charges in the Company's original filing were also removed in the Stipulation. He testified that the Company has to arrange winter supplies to provide to transportation customers when transportation is no longer available. He also said that in providing transportation services, the company must do all of the things it would do for a sales customer. The Company must balance and schedule gas volumes between the producer and the customer. On redirect, Public Service witness Dickey testified that full margin transportation rates were used in the Company's last general rate case and also have been used in all Orders of the Commission relating to transportation for Public Service as well as Piedmont Natural Gas Company, Inc., North Carolina Natural Gas Corporation and Pennsylvannia and Southern Gas Company. The transportation rates agreed to by the Company and the Public Staff in the Stipulation are full margin rates. He also said that there has been no material change in the services rendered by the Company to transportation customers since the Company's last rate case.

CUCA argues that full margin rates contain "fixed gas costs" which consist of payments made in order to obtain the delivery of natural gas volumes to the Company's city gate. CUCA contends that entities transporting their own customer-owned gas are required to separately contract with and pay for the delivery of that gas to Public Serivces' city gate. CUCA also states that transportation rates, like natural gas sales rates, should be based primarily upon cost-of-service considerations.

CUCA's position has been consistently rejected and the full margin concept has been adopted as appropriate in all recent natural gas utility rate cases. This includes the Company's last general rate case (Docket No. G-5, Sub 248) and the most recent natural gas utility rate cases decided for the other three natural gas companies regulated by the Commission. The original rate designs contained in both witnesses' pre-filed testimony and the stipulated rate design of this case established transportation rates using the full margin concept.

CUCA's contention that transportation rates should be based primarily on cost-of-service studies is rejected for the same reasons set forth in the earlier discussion on cost-of-service studies and factors in rate design.

The Commission continues to find no justification for a difference between the margins earned on the Company's sales rate schedules and its transportation rate schedules. The Commission concludes that the services performed by the Company are substantially the same whether service is provided under the sales rate or transportation rate. The Commission concludes that full margin transportation rates continue to be just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 86-91

The evidence for these findings is contained in the testimony and exhibits of Company witnesses Dickey, Voigt, and Zeigler and Public Staff witness Davis and in Late Filed Public Service Company Exhibit 4.

In its existing rates, Public Service utilizes Rider D, a mechanism intended to accomplish a number of different purposes, including the recoupment of "margin" lost as the result of negotiated sales, the passing of commodity cost savings through to sales rate customers, and the collection of certain changes in "fixed gas costs" and commodity costs.

As part of its application in this proceeding, Public Service has proposed to modify Rider D in order to permit the 100% recovery of all commodity and "fixed gas costs," including a "truing-up" of both types of costs. The Company asks the Commission to approve the proposed revised Rider D pursuant to the Commission's general authority to approve ratemaking formulas in a context of a general rate case. See Utilities Commission v. NCNG, 323 N.C. 630, 375 S.E.2d 147 (1989); Utilities Commission v. CF Industries, 299 N.C. 504, 263 S.E.2d 559 (1980); Utilities Commission v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976); Utilities Commission v. Public Service Company, 35 N.C. App. 156, 241 S.E.2d 79 (1978). Although the Public Staff opposed approval of a mechanism permitting the Company to obtain rate changes based upon additional pipeline capacity costs, Public Service and the Public Staff stipulated that until further Order by the Commission, Public Service shall be entitled to collect additional pipeline capacity and storage costs on a provisional basis (not otherwise included in the cost authorized to be collected under the Order in this case) and to place such monies in a deferred account. The monies shall remain in the deferred account "pending further order of the Commission." The version of Rider D embodied in the Stipulation between Public Service and the Public Staff permits Public Service to provisionally recover additional pipeline capacity costs and to change rates for all customers based upon fluctuations in "fixed gas costs" from all sales and transportation customers.

On July 8, 1991, the General Assembly enacted Chapter 598 of the 1991 Session Laws. This legislation amends Chapter 62 of the General Statutes by adding G.S. 62-133.4. This new statute authorizes the Commission to allow rate changes "occasioned by changes in the cost of natural gas supply and may include all costs related to the purchase and transportation. . . " The new statute also provides for an annual review to "compare the utility's prudently incurred costs with costs recovered from all the utility's customers that it served during the test period." If prudently incurred costs are greater or less than recovered costs, the Commission shall require the utility to refund any overrecovery or permit the utility to recover any deficiency. Finally, the new statute provides that the "costs" subject to the statute shall be "defined by Commission rule or order and may include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system." The Commission has initiated proceedings, separate from this general rate case, in Docket G-100, Sub 58, in order to define "costs" for purposes of G.S. 62-133.4 and in order to provide for implementation of G.S. 62-133.4.

Stipulation Schedule 4 Revised, in Public Service Company's Exhibit 4, contains language that reflects the current practice with regard to allocating fixed Demand and Storage costs by multiplying the per unit amount of fixed Demand and Storage costs in each rate schedule by the actual volumes for that rate schedule. This language clarifies the proposed treatment of those costs.

CUCA complained that the Company's Rider D effectively assigns fixed gas costs to all sales and transportation customers on an equal, per dekatherm basis. CUCA also opposed the recovery of additional pipeline capacity costs through Rider D.

The Commission believes that Stipulation Schedule 4 Revised, filed with Late Filed Public Service Exhibit 4, clarifies the treatment of fixed gas costs.

The Commission concludes that Docket G-100, Sub 58 is the appropriate forum in which CUCA can argue the merits of the recovery of additional pipeline capacity costs in Rider D. Approval by the Commission of the revised Rider D on a provisional basis in this docket will not injure CUCA.

To avoid any gap between the operation of Public Service's old Rider D and implementation of the new statute G.S. 62-133.4, the Commission approves the revised Rider D embodied in the Stipulation between Public Service and the Public Staff in this case. This approval shall be provisional in the sense that the Commission recognizes that the revised Rider D may be superseded by the procedures adopted to implement G.S. 62-133.4. The costs subject to the provisional revised Rider D which relate to additional pipeline capacity and storage shall be subject to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G. S. 62-133.4. Any monies so collected which are associated with additional pipeline capacity and storage shall be placed in a deferred account pending further Order of the Commission.

Provisional approval of the revised Rider D as proposed by Public Service to include the costs of additional pipeline capacity and storage is made without prejudice to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G.S. 62-133.4.

The Commission concludes that the revised Rider D embodied in the Stipulation proposed by the Company and the Public Staff should be approved on a provisional basis, as hereinabove provided, pending implementation of G. S. 62-133.4.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NUMBERS 92-99

The evidence for these findings is contained in the testimony of Public Service witnesses Dickey and Voigt and Public Staff witness Davis and the Stipulation.

In its original prefiled testimony and exhibits, Public Service proposed certain modifications to its service regulations and certain increases in incidental fees. In the Stipulation between Public Service and the Public Staff, the Company's request for increased reconnection fees, after-hours service fees, and seasonal residential and small commercial facility charges were accepted by the Public Staff and a set of revised service regulations were approved.

With the exception of one portion of the proposed service regulations, neither the Attorney General, the City of Durham, nor CUCA objected to these proposals. The only issue concerning Public Service's proposed service regulations objected to by CUCA involves the Company's request that industrial customers have no more than one alternate fuel per delivery. Company witness Dickey testified that the provision was necessary to ensure that the negotiated rate program is administered fairly and that no one takes advantage of the program.

The Commission agrees that it would be unfair to allow an industrial customer using two or more alternate fuels to negotiate the price of its entire gas load on the basis of its lowest alternate fuel price unless the fuel used for negotiation can replace the entire load. Separate metering will allow all gas volumes to be priced properly. The Commission concludes that revised service regulations in the Stipulation between Public Service and the Public Staff should be approved for service from and after the effective date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 100-108

The evidence for these findings is contained in the testimony and exhibits of Company witnesses Dickey, Voigt, and Zeigler and Public Staff witness Davis and the Stipulation.

The Company has proposed to implement a Weather Normalization Adjustment clause which will bill weather-sensitive sales rate customers as if normal weather had occurred. The purpose of the proposed Weather Normalization Adjustment clause is to minimize the financial impact of abnormal weather upon Public Service's revenues and earnings. The Stipulation between the Company and the Public Staff recommended the approval of Public Service's proposed Weather Normalization Adjustment clause. Neither the Attorney General, the City of Durham, nor CUCA opposed this portion of the Stipulation. As a result, the Company is authorized to implement the Weather Normalization Adjustment clause in the form embodied in the Stipulation between Public Service and the Public Staff from and after the date of this Order. The parties should work together to derive an appropriate form to be used to meet the filing requirements of the Weather Normalization Adjustment clause.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 109-112

The evidence for these findings is contained in the testimony of Public Staff witness Davis and the Stipulation.

In its original prefiled testimony, the Public Staff requested Commission approval for a true-up of Public Service's unaccounted for volumes. According to the Public Staff, the implementation of such a true-up will prevent the Company from underrecovering or overrecovering its unaccounted for volumes. The Stipulation between Public Service and the Public Staff provided that Public Service's unaccounted for volumes should be trued-up on an annual basis. Neither the Attorney General, the City of Durham, nor CUCA opposed this recommendation. As a result, the Commission concludes that Public Service's unaccounted for volumes should be trued-up on an annual basis in the manner set forth herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NUMBERS 113-120

The evidence for these findings is contained in the testimony of Public Staff witness Hinton and the Stipulation.

In her original prefiled testimony and exhibits, witness Hinton set forth concerns regarding certain general accounting matters. In the Stipulation between Public Service and the Public Staff, the parties have agreed to the manner in which these accounting matters are to be treated. Accordingly, upon consideration of the Stipulation and the Commission's approval of the Company's Rider D, the Commission concludes that these general accounting matters should be treated as set forth in the Stipulation.

IT IS, THEREFORE, ORDERED as follows:

1. That Public Service Company of North Carolina, Inc., be, and is hereby, allowed to increase its rates and charges so as to produce an annual level of revenue of $240,516,112 (including $10,005,737 of other operating revenue and assuming a $2.50 cost of gas) from its customers based upon its test period level of operations. Such amount represents an increase of $5,299,074 above the level of revenues that would have resulted from rates in effect during the test period.

2. That the rates shown on Stipulation Schedule 2, Revised, be, and the same are hereby, approved effective for service rendered on and after November 1, 1991.

3. That the service regulations set forth in the Stipulation, as revised, be, and the same are hereby, approved effective for service rendered on and after November 1, 1991.

4. That the Rider D tariff set forth in the Stipulation, as revised, be, and the same is hereby, approved effective for service rendered on and after the date of this Order, on a provisional basis, in the sense hereinabove provided, pending implementation of G.S. 62-133.4. Any monies so collected which are associated with additional pipeline capacity and storage shall be placed in a deferred account pending further Order of the Commission.

5. The Weather Normalization Adjustment clause set forth in the Stipulation be, and the same is hereby, approved effective for service rendered on and after November 1, 1991.

6. That the accounting procedures contained in the Stipulation between the Company and the Public Staff shall be implemented from and after the date of this Order.

7. That Public Service Company of North Carolina, Inc., shall file appropriate tariffs, including its service regulations, Rider D, and Weather Normalization Adjustment clause, in accordance with the provisions of this Order, not later than ten (10) days from the date of this Order. Said tariffs shall be properly adjusted for any PGA adjustments and for any temporary increments and decrements currently in effect.

8. That Public Service Company of North Carolina, Inc., shall send the Notice attached hereto as Appendix A to its customers by appropriate bill inserts in the next billing cycle following the effective date of the new tariffs.

9. That the tariffs filed in response to decretal Paragraph 7 above shall be subject to approval by further order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of November 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. G-5, SUB 280

In the Matter of Application of Public Service Company of North Carolina, Inc. for an Adjustment of its Rates and Charges	)	PUBLIC NOTICE

The North Carolina Utilities Commission issued an Order allowing Public Service Company of North Carolina, Inc. ("Public Service" or "the Company") to increase its rates and charges by approximately $5.3 million annually, as well as to roll-in approximately $12.8 million of deferred gas costs which were previously collected under surcharge increments into the Company's base rates. The overall increase allowed was 3.63%, effective November 1, 1991.

The Company's application for a rate increase was filed with the Commission on April 1, 1991. Public Service initially requested an increase of approximately $8.9 million in revenues and the right to roll-in approximately $13.8 million in deferred gas costs into its base rates. The Company and Public Staff of the Utilities Commission reached an overall settlement and entered into a Stipulation regarding the amount of the proposed increase.

In its application, Public Service stated that it has been adding customers and making capital investments in its utility properties, both at unprecedented levels, and obtaining new long-term capital from the sales of securities. The reasons cited by Public Service in support of a rate increase were to allow it to maintain its facilities and services in accordance with the reasonable requirements of its customers, to compete in the market for capital funds on fair and reasonable terms and to produce a fair profit for its stockholders.

The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service.

A typical year-round residential customer's annual bill will increase approximately 4.4% based upon 866 therms of gas usage per year.

In allowing the increase, the Commission found that the approved rates would provide Public Service, under efficient management, an opportunity to earn an approximate 11.10% rate of return on its rate base devoted to providing utility service in North Carolina. This is a reduction from 11.44% approved in the Company's last general rate case in 1989.

ISSUED BY ORDER OF THE COMMISSION.
This the 1st day of November 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-9, SUB 309

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Its Rates and Charges) ORDER ALLOWING INTERIM RELIEF

BY THE COMMISSION: On December 21, 1990, Piedmont Natural Gas Company, Inc. (Piedmont), filed an application with the Commission for authority to adjust and increase its rates and charges for retail natural gas service in North Carolina. As a part of that application, Piedmont requested on an interim basis (1) the reapproval of the Purchased Gas Adjustment Clause previously approved in Docket No. G-9, Subs 289, 291, and 296, and (2) approval to recover as interim rates the amounts previously approved in Docket No. G-9, Subs 289, 291, 296, 300, 306, and 308.

On January 18, 1991, the Commission issued its Order declaring Piedmont's application to be a general rate case, suspending the proposed rates, and scheduling the application for hearing.

On January 17, 1991, the Commission issued its Order scheduling an oral argument on Piedmont's request for interim relief. That argument was held on January 25, 1991. Piedmont, the Public Staff, and Intervenor Carolina Utility Customers Association, Inc., participated. In brief, Piedmont argued that it is not requesting any change in the rates presently in effect. Instead, Piedmont is merely seeking additional legal authority for the level of rates already approved by the Commission in previous dockets which have been appealed. In general, both the Public Staff and CUCA argued that interim rates should only be allowed in a general rate case when the utility faces a financial emergency justifying immediate relief and that Piedmont has made no such showing.

G.S. 62-134(a) provides that no public utility shall make any change in duly established rates except after 30 days' notice to the Commission. The statute goes on to provide, "The Commission, for good cause shown in writing, may allow changes in rates without requiring the 30 days' notice, under such circumstances as it may prescribe." As the Supreme Court has held,

> This section clearly authorizes the Commission by an affirmative order to "allow" applied for rate changes to go into effect even before the expiration of the thirty days' notice period "under such circumstances as it may prescribe." The power to prescribe conditions, like the power to suspend rate changes, includes the power to refrain from prescribing them. Thus, the Commission by its affirmative order may allow applied for rate changes to become immediately effective conditionally or unconditionally.

Utilities Commission v. Edmisten, 291 N.C. 327, 351-52, 230 S.E. 2d, 651 (1976). The statute grants the Commission broad discretion with respect to allowance of interim relief in a general rate case.

Piedmont is requesting the Commission to reapprove as interim relief both the Purchased Gas Adjustment Clause previously approved in Docket No. G-9, Subs 289, 291, and 296 (none of which was a general rate case) and the rate adjustments previously approved by the Commission in Docket No. G-9, Subs 289, 291, 296, 300, 306, and 308 (none of which was a general rate case). The Commission's previous orders in these dockets have been appealed by CUCA. Both the Purchase Gas Adjustment Clause and the rate adjustments cited are being challenged as improper outside the context of a general rate case. Piedmont asserts in its application herein that the interim relief requested "will not result in a change in the rates presently being collected by Piedmont but will provide additional authority for Piedmont to collect the amounts previously authorized by the Commission."

The Commission finds good cause to grant the interim relief requested by Piedmont. It is true, as argued by the Public Staff, that the Commission's practice is to view interim relief in a general rate case as an extraordinary measure to be granted only when the utility faces an actual financial emergency requiring immediate relief. Piedmont has not shown such a financial emergency. The Commission nonetheless finds interim relief appropriate. We view the interim relief allowed herein as an exception to, not a deviation from, the "financial emergency" standard. In other cases when a utility has sought interim relief, the utility has proposed to increase rates. In the present case, Piedmont is not proposing any change in the rates previously approved. Rates will neither go up nor down as a result of our decision today. Piedmont is merely seeking additional legal authority for current rates, which are being challenged by CUCA in its appeals. Having previously found the current level of rates to be reasonable, the Commission finds good cause to reapprove that level of rates in the present context. The Commission views the present circumstances as unique, and does not intend to set any precedent for other circumstances.

The interim rates approved herein shall be subject to refund if not approved by the final order issued in the present general rate case.

IT IS, THEREFORE, ORDERED as follows:

1. That the Purchased Gas Adjustment Clause previously approved in Docket No. G-9, Subs 289, 291, 296, should be, and hereby is, reapproved as interim relief herein;

2. That the rate adjustments previously approved in Docket No. G-9, Subs 289, 291, 296, 300, 306, and 308, should be, and hereby are, reapproved as interim relief herein; and

3. That the interim relief approved herein shall be subject to refund if not ultimately approved in the final order issued in the present general rate case.

ISSUED BY ORDER OF THE COMMISSION.
This the 5th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

Commissioners Cook and Hughes dissent.

COMMISSIONER RUTH E. COOK, DISSENTING

I dissent from the interim rates allowed herein because I believe that the majority's decision departs from the previous policy of the Commission which has used the "financial emergency" standard in determining whether a utility should be granted interim rates in a general rate case proceeding. That standard has been used consistently in every case of which I am aware. The majority concedes that Piedmont has not shown any financial emergency.

The majority nonetheless allows interim rates on the specious grounds that it will not change current rates and that it is merely granting Piedmont additional legal authority for previous Commission orders which are being challenged by appeal. I believe that the first point is incorrect and that the second point is ill advised.

Without interim relief, Piedmont will be required to make refunds if the Commission's previous orders are overturned on appeal. The refunds would probably run from the time the Commission entered its previous orders until the time it enters its final order in this general rate case. With interim relief, Piedmont will be protected from today's date forward even if it loses the appeals. Thus, the majority's decision <u>will</u> result in a change in rates <u>if</u> CUCA is successful on appeal.

Turning to the majority's second point, it must be remembered that Piedmont itself chose to make its previous filings outside the context of a general rate case. Piedmont felt that its filings were proper. The Commission granted relief in those filings. Some of the relief was based on a negotiated settlement between Piedmont and the Public Staff which weighed several factors, including the legality of Piedmont's filings.

CUCA is now challenging the Commission's decisions on grounds that the relief granted can only be allowed in general rate cases. Despite its previous assurances to the Commission, Piedmont now seems to fear that CUCA is correct. I believe that the Commission's previous orders should stand or fall on their own merits, without being propped up by the majority's decision today. The prospect of interim rate relief was not a part of those previous filings and negotiations. The majority's decision effectively allows Piedmont to change its strategy after the fact, thus creating a win-win situation for Piedmont. I find that to be an exceedingly inappropriate action for the majority to take. This Commission should not be about shoring up Piedmont's house of cards, and I therefore dissent.

Ruth E. Cook, Commissioner

DOCKET NO. G-9, SUB 309

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Piedmont Natural Gas Company, Inc., for an Adjustment of its Rates and Charges	)))	ORDER GRANTING PARTIAL RATE INCREASE

HEARD IN: Mecklenburg Criminal Court Building, Charlotte, North Carolina, on April 30, 1991; Guilford County Courthouse, Greensboro, North Carolina, on May 1, 1991; and Commission Hearing Room, Dobbs Building, Raleigh, North Carolina, on May 7-8, 1991

BEFORE: Commissioner Laurence A. Cobb, Presiding; Chairman William W. Redman; and Commissioner Robert O. Wells

APPEARANCES:

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For Carolina Utility Customers Association, Inc.:

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BY THE COMMISSION: On December 21, 1990, Piedmont Natural Gas Company, Inc. (also referred to as Piedmont, Applicant, or the Company), filed an application with the Commission requesting (1) an adjustment of its rates and charges for natural gas service to its North Carolina retail customers to become effective January 21, 1991, (2) the approval of revised service regulations, (3) the reapproval of the Purchased Gas Adjustment Clause (PGA Clause) previously approved in Docket No. G-9, Subs 289, 291 and 296, on an interim basis pending a final order in this docket, (4) the issuance of an order authorizing Piedmont to recover as an interim rate increase during any suspension period ordered by the Commission in this docket the amounts authorized in Docket No. G-9, Subs 289, 291, 296, 300, 306 and 308, (5) the approval of a revised PGA Clause effective on the effective date of the proposed rates and (6) the approval of a Weather Normalization Adjustment Clause (WNA Clause). The Company filed testimony and exhibits in support of its application.

On January 14, 1991, the Carolina Utility Customers Association, Inc. (CUCA), filed a Petition to Intervene, and on January 15, 1991, the Commission issued an order granting the petition.

On January 17, 1991, the Commission issued an order scheduling oral argument on Piedmont's request for interim relief.

On January 18, 1991, the Commission (1) suspended the proposed rate increase for a period of up to 270 days and set the matter for investigation and hearing, (2) scheduled hearings, (3) declared the application to be a general rate case under G.S. 62-137, (4) gave notice that the Commission would determine the appropriate level of rates to be established for each individual rate class, (5) established the test period to be used in the proceedings, (6) required the

Company to give public notice of the application and the hearings, (7) notified other persons of their right to intervene and (8) established dates for the filing of testimony and exhibits by the parties.

On January 25, 1991, the Commission heard oral arguments on Piedmont's request for interim relief. At that time, arguments were presented by Piedmont, the Public Staff and CUCA.

On February 5, 1991, the Commission issued its Order Allowing Interim Relief. In that order, the Commission (1) reapproved the PGA Clause previously approved in Docket No. G-9, Subs 289, 291 and 296, on an interim basis pending a final order in this docket and (2) reapproved the rate adjustments previously approved in Docket No. G-9, Subs 289, 291, 296, 300, 306 and 308, as interim relief in this docket.

On March 28, 1991, the N. C. Attorney General filed its Notice of Intervention.

On April 17, 1991, the Public Staff and CUCA filed testimony and exhibits.

On April 30, 1991, the matter came on for hearing as scheduled. At the hearing in Charlotte, Susan Hancock and Larry Schuster testified as public witnesses.

On May 1, 1991, the hearing was continued in Greensboro, at which time W. Porter Lowdermilk, Dan Lynch and Thomas L. Stapleton testified as public witnesses.

On May 7, 1991, the Company and the Public Staff filed a stipulation in which they agreed to resolve a number of issues raised by the Public Staff in its prefiled testimony and exhibits. Neither CUCA nor the Attorney General were parties to this stipulation.

The case in chief came on for hearing as scheduled in Raleigh. Caroline Myers testified as a public witness. The Company presented the testimony and exhibits of the following witnesses:

1. John H. Maxheim, President, Chairman of the Board and Chief Executive Officer of Piedmont;

2. Barry L. Guy, Vice President and Controller of Piedmont;

3. Dr. Donald A. Murry, Economist with C. H. Guernsey & Company and Professor of Economics at the University of Oklahoma;

4. Bill R. Morris, Director of Rates of Piedmont;

5. Ann H. Boggs, Manager of Gas Accounting of Piedmont;

6. Chuck W. Fleenor, Vice President of Gas Supply of Piedmont; and

7. Ware F. Schiefer, Senior Vice President of Gas Supply and Transportation of Piedmont.

CUCA presented the testimony and exhibits of Donald W. Schoenbeck of Regulatory and Cogeneration Services, Incorporated.

The Public Staff presented the testimony and exhibits of the following witnesses:

1. George T. Sessoms, Public Utilities Financial Analyst and Director of the Economic Research Division of the Public Staff - North Carolina Utilities Commission;

2. James G. Hoard, Supervisor of the Natural Gas Section in the Accounting Division of the Public Staff;

3. Eugene H. Curtis, Jr., Public Utilities Engineer with the Natural Gas Division of the Public Staff.

On June 5, 1991, the Company and the Public Staff filed a motion to file a late exhibit to correct Schedule V of the stipulation. Schedule V shows the proposed rates pursuant to the stipulation that Piedmont and the Public Staff filed on May 7, 1991. The correct proposed rates are shown on Late Filed

Schedule V Revised Corrected which was filed by the Public Staff on June 5, 1991. The motion was granted on June 18, 1991.

On June 18, 1991, CUCA filed a Motion to Submit Late-Filed Exhibits. CUCA filed a Motion to correct the Motion on July 10, 1991. Piedmont filed a letter to the effect that it does not object to the Motion, but disagrees with the rates proposed by CUCA. The Commission allowed the Motions on July 11, 1991.

Based upon the verified application, the testimony and exhibits received into evidence at the hearings and the record as a whole, the Commission makes the following:

FINDINGS AND CONCLUSIONS

1. The Company is engaged in the business of transporting, distributing and selling gas in 42 North Carolina communities.

2. Among other things, the Company is seeking an increase in its rates and charges for natural gas service to its North Carolina customers.

3. No party has raised a question with respect to the jurisdiction of the Commission over the matters at issue in this case.

4. The Company is a public utility within the meaning of G.S. 62-3(23).

5. The Commission has jurisdiction over, among other things, the rates and charges of public utilities, including the Company.

6. The Company's application, testimony, exhibits, Form G-1 and publication of notices of hearing are in compliance with the provisions of Chapter 62 and the Rules and Regulations of the Commission.

7. The Commission concludes that the Company is properly before the Commission for a determination of the justness and reasonableness of its rates and charges as regulated by the Commission under Chapter 62 of the General Statutes of North Carolina.

8. The only parties submitting evidence in this case with respect to revenue, expenses and rate base used a test period of the twelve months ended October 31, 1990, updated for the most part through March 31, 1991.

9. No party objected to the use of the updated test period.

10. It is appropriate to establish a test period of twelve months, ending as close as practicable to the end of the hearing. G.S. 62-133; N.C.U.C. Rule 1-17(c).

11. The Commission concludes that the appropriate test period for use in this proceeding is the twelve months ended October 31, 1990, updated primarily through March 31, 1991, but also updated to reflect certain changes which occurred up to the time that the hearing was closed.

12. The Company is presently adding customers at four times the national average and expects to continue adding customers at the same level for the next five years.

13. The Company provides assistance to public agencies and is responsive to the needs of the business community.

14. The Commission finds and concludes that the Company is providing good natural gas service to its customers.

15. On February 5, 1991, the Commission issued its Order Allowing Interim Relief in this docket by which it (1) reapproved the old PGA Clause previously approved in Docket No. G-9, Subs 289, 291, and 296, on an interim basis pending issuance of the present Order and (2) reapproved the rate adjustments previously approved in Docket No. G-9, Subs 289, 291, 296, 300, 306, and 308, as interim relief pending issuance of the present Order.

16. Prior to hearing, the Company and the Public Staff settled most of the issues on which they had differed. The settlement terms were incorporated in the Stipulation of Piedmont Gas Company, Inc. and the Public Staff, which was introduced in evidence as Exhibit JHM-2.

17. The Company's actual "operating revenues from the sale and transportation of gas" during the test period were $214,653,231.

18. The Company proposed pro forma "operating revenues from the sale and transportation of gas" under present rates of $302,881,586, assuming a $3.4524 commodity cost of gas.

19. The Public Staff proposed pro forma "operating revenues from the sale and transportation of gas" under present rates of $313,347,849, assuming a $3.4524 commodity cost of gas.

20. The difference between the pro forma revenues from the sale and transportation of gas as proposed by the Company and by the Public Staff results from the different volumes of gas used to calculate revenue.

21. Actual test period volumes were 56,836,104 dts.

22. The Company proposed pro forma sales and transportation volumes of 58,302,816 dts.

23. The Public Staff originally proposed pro forma sales and transportation volumes of 60,323,750 dts. The Public Staff increased its proposed pro forma sales and transportation volumes to 60,358,883 dts., an increase of 35,133 dts., through the supplemental testimony of witness Curtis.

24. In the stipulation, the Company and the Public Staff agreed to pro forma sales and transportation volumes of 60,358,883 dts. This figure does not include company use or unaccounted-for volumes.

25. No other party offered any evidence on pro forma sales and transportation volumes.

26. The application of end of test period rates to pro forma sales and transportation volumes will produce pro forma test period revenues of $313,347,849.

27. G.S. 62-133(2) requires the Commission to estimate the Company's revenues under present rates.

28. Since revenues from the sale and transportation of gas depend, in part, upon the volume of gas sold and transported, the Commission must determine these volumes.

29. Test period data should be adjusted to reflect any abnormality having a probable impact on the Company's revenues. G.S. 62-133(f); Utilities Commission v. Thornburg, 316 N.C. 238, 252, 342 S.E. 2d 28, 37-38 (1986); Utilities Commission v. Carolina Utilities Customers Association, 314 N.C. 171, 189, 333 S.E. 2d 259, 270 (1985).

30. Test period volumes should be increased by 1,466,712 dts. to annualize the conditions which existed from time to time during the test period to those conditions which existed at the end of the updated test period.

31. Actual test period volumes should be adjusted to reflect normal weather conditions.

32. Under the facts and circumstances of this case, it is proper to assume growth in sales and transportation volumes to high priority customers without requiring a corresponding decrease in volumes to industrial customers.

33. Under the facts and circumstances of this case, it is proper to project growth in sales and transportation volumes through March 31, 1991, to obtain a proper matching of revenues and plant.

34. Pro forma "operating revenues from the sale and transportation of gas" under present rates should be adjusted by a revenue adjustment factor to reflect the fact that not all volumes are sold at filed rates.

35. The revenue adjustment factors used to adjust revenues are just and reasonable.

36. The appropriate pro forma volumes are 60,358,883 dts. consisting of test period volumes of 56,836,104 dts., plus an annualization adjustment of 1,466,712 dts. and plus weather and growth adjustments of 2,056,067 dts. This figure does not include company use or unaccounted-for volumes.

37. The Company can reasonably expect to receive pro forma "operating revenues from the sale and transportation of gas" under present rates of $313,347,849 based on the expected sale of 60,358,883 dts. of gas and an assumed commodity cost of gas of $3.4524.

38. The Commission concludes that the appropriate pro forma level of "operating revenues from the sale and transportation of gas" under present rates is $313,347,849.

39. The Company's actual "other operating revenue" during the test period was $535,624.

40. The Company's actual "other operating revenue" under present rates represents a reasonable going level under present rates.

41. The Commission concludes that the appropriate pro forma level of "other operating revenue" under present rates is $535,624.

42. Total pro forma operating revenue under present rates is the sum of pro forma "operating revenue from the sale and transportation of gas" under present rates and pro forma "other operating revenue" under present rates.

43. Total pro forma "operating revenue from the sale and transportation of gas" under present rates is $313,347,849 as determined herein.

44. Total pro forma "other operating revenue" under present rates is $535,624 as determined herein.

45. The Company can reasonably expect to receive pro forma total operating revenue under present rates of $313,883,473 based on the expected sale of 60,358,883 dts. of gas and an assumed commodity cost of gas of $3.4524.

46. The Commission concludes that the appropriate pro forma level of "total operating revenue" under present rates is $313,883,473.

47. The Company's actual "gas costs" during the test period were $122,675,243.

48. The Company proposed pro forma "gas costs" under present rates of $205,467,628, assuming a $3.4524 commodity cost of gas.

49. The Public Staff proposed pro forma "gas costs" under present rates of $209,865,496, assuming a $3.4524 commodity cost of gas.

50. The difference between the pro forma "gas costs" as proposed by the Company and by the Public Staff results from the different volumes of gas used to calculate the "cost of gas," from changes in certain rates to reflect more current billings by interstate pipelines and from different allocations of joint fixed gas costs between North Carolina and South Carolina.

51. In the Company's last North Carolina general rate case, Docket No. G-9, Sub 278, 78% of the fixed gas costs were allocated to North Carolina.

52. The percentage of gas delivered to North Carolina during any period of time depends upon a number of factors, including the time period used to calculate the percentage. For example, 79.22% was delivered during the three-day sustained peak and 74.44% was delivered during the 365-day test period.

53. Using the pro forma volumes previously found appropriate, a $3.4524 commodity cost of gas, current wholesale gas rates and a 78% allocation of fixed gas costs to North Carolina produce a pro forma cost of gas of $211,707,096.

54. There is no single best way of allocating fixed gas costs between North Carolina and South Carolina.

55. Fixed gas costs should be allocated between North Carolina and South Carolina in a method that best assigns to each jurisdiction the costs that were incurred for that jurisdiction.

56. The allocation of 78% of the fixed gas costs to North Carolina is fair and reasonable under the facts and circumstances of this case. It is consistent with the amount allocated in the Company's last general rate case, and it represents a reasonable compromise between the 79.22% proposed by the Company and the 76.85% proposed by the Public Staff.

57. The Commission concludes that the appropriate pro forma level of "cost of gas" under present rates is $211,707,096.

58. The regulatory fee expense is a function of revenues.

59. The difference between the regulatory fee expense as proposed by the Company and the Public Staff results from the fact that the Company calculated the fee on projected revenues assuming a $3.4524 per dt. commodity cost of gas and the Public Staff calculated the fee on test period revenues.

60. In the stipulation, the Company and the Public Staff agreed on a regulatory fee expense of $315,111.

61. No party other than the Company and the Public Staff offered any evidence on the level of regulatory fee expense.

62. The uncollectibles expense is a function of revenues.

63. The difference between the uncollectibles expense as proposed by the Company and as proposed by the Public Staff results from the fact that the Company calculated the expense on projected revenues assuming a $3.4524 per dt. commodity cost of gas and the Public Staff calculated the expense on test period revenues.

64. In the stipulation, the Company and the Public Staff agreed on an uncollectibles expense of $533,364.

65. No party other than the Company and the Public Staff offered any evidence on the level of uncollectibles expense.

66. The differences between the amount of expense included for payroll results from (1) the fact that the Company did not properly recognize the payroll allocations to affiliates in its payroll adjustment, (2) the fact that the Company had a mathematical error in its computation of the operation and maintenance expense payroll percentage and (3) the fact that the Public Staff estimated the March merit pool; whereas, the Company used actual March numbers.

67. In the stipulation, the Company and the Public Staff agreed on the amount to be included in payroll expenses with respect to the merit pool.

68. No party other than the Company and the Public Staff offered any evidence on the level of expenses which should be included with respect to payroll.

69. At the time of the close of the hearing, G.S. 62-302 required public utilities regulated by the Commission to pay a regulatory fee of .12% of the quarterly revenues each quarter.

70. Although the agreed upon collectible revenues ($262,592,860) are somewhat less than the revenues approved in this case of $272,857,407, it is reasonable to assume that the Company's actual revenues will be somewhat less for regulatory expense purposes to reflect gas costs which are somewhat lower than the $2.50 per dt. used in the calculation of revenues.

71. Under the facts and circumstances of this case, it is appropriate that the regulatory fee be based on agreed upon collectible revenues of $262,592,860.

72. Although the agreed upon revenues ($262,592,860) are somewhat less than the revenues approved in this case of $272,857,407, it is reasonable to assume that the Company's actual revenues for the purpose of determining uncollectibles will be somewhat less to reflect gas costs which are somewhat lower than the $2.50 per dt. used in the calculation of revenues.

73. Under the facts and circumstances of this case, it is appropriate that the regulatory fee be based on agreed upon collectible revenues of $262,592,860.

74. It is appropriate to determine the merit pool going level at March 31, 1991, using actual March 1991 numbers as proposed by Company witness Guy in his rebuttal testimony and agreed to by the Public Staff in the stipulation.

75. It is appropriate to allocate a portion of the payroll to affiliates as proposed by Public Staff witness Hoard and agreed to by Company witness Guy.

76. It is appropriate to correct the mathematical error in the computation of the operation and maintenance expense payroll percentage as proposed by Public Staff witness Hoard and agreed to by Company witness Guy.

77. The appropriate level of advertising expenses to be included in pro forma operation and maintenance expense is that recorded in the test period.

78. It is appropriate to adjust pro forma rate case expenses as proposed by Public Staff witness Hoard and agreed to by the Company in the stipulation.

79. It is appropriate to adjust insurance expense to allocate a portion of the expense to construction and non-utility operations as proposed by Public Staff witness Hoard and agreed to by the Company in the stipulation.

80. It is appropriate to adjust insurance expense to reflect the current premium levels for property and directors' and officers' liability insurance policies as proposed by Public Staff witness Hoard and agreed to by the Company in the stipulation.

81. It is appropriate to increase operation and maintenance expense by $130,926 to reflect increases in postage rates that became effective in February 1991 as proposed by Public Staff witness Hoard and agreed to by the Company in the stipulation.

82. It is not necessary to adjust operation and maintenance expense to remove any of the $25,965 paid to the Company's consultant.

83. The Commission concludes that the appropriate pro forma level of "operation and maintenance expense" under present rates is $44,687,059.

84. The Company and the Public Staff have stipulated to a going level of depreciation expense of $9,494,733.

85. No other party offered any evidence on the appropriate level of depreciation expense.

86. The going level of depreciation expense agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of depreciation expense.

87. The Commission concludes that the appropriate pro forma level of "depreciation expense" under present rates is $9,494,733.

88. The Company and the Public Staff have stipulated to a going level of general taxes of $14,879,648.

89. No other party offered any evidence on the appropriate level of general taxes.

90. The Company and the Public Staff have stipulated to a going level of state income taxes of $1,401,835.

91. No other party offered any evidence on the appropriate level of state income taxes.

92. The Company and the Public Staff have stipulated to a going level of Federal income taxes of $6,236,035.

93. No other party offered any evidence on the appropriate level of Federal income taxes.

94. The appropriate North Carolina gross receipt tax rate is 3.22%.

95. At the time of the close of the hearing, the North Carolina state income tax rate was 7%.

96. The appropriate Federal income tax rate is 34%.

97. The method used by the Public Staff to compute gross receipts taxes, state income taxes and Federal income taxes is appropriate.

98. The going level of general taxes agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of general taxes expense.

99. The going level of state income taxes agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of state income taxes expense.

100. The going level of Federal income taxes agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of Federal income taxes expense.

101. The Commission concludes that the appropriate pro forma levels of "general taxes," "state income taxes" and "Federal income taxes" are $14,879,648, $1,401,835 and $6,236,035, respectively, under present rates.

102. The Company and the Public Staff have stipulated to a going level of "amortization of investment tax credits" of $310,621.

103. No other party offered any evidence on the appropriate level of "amortization of investment tax credits."

104. In the absence of any evidence to the contrary, the going level of "amortization of investment tax credits" agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of that expense.

105. The Commission concludes that the appropriate pro forma level of "amortization of investment tax credits" under present rates is $310,621.

106. The Company and the Public Staff have stipulated to a going level of interest on customer deposits of $200,181.

107. No other party offered any evidence on the appropriate level of interest on customer deposits.

108. In the absence of any evidence to the contrary, the going level of interest on customer deposits agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of that expense.

109. The Commission concludes that the appropriate pro forma level of interest on customer deposits under present rates is $200,181.

110. The Company and the Public Staff have stipulated to a going level of amortization of bond defeasance gain of $64,560.

111. No other party offered any evidence on the appropriate level of amortization of bond defeasance gain.

112. In the absence of any evidence to the contrary, the going level of amortization of bond defeasance gain agreed to by the Company and the Public Staff in the stipulation represents a reasonable estimate of the going level of that expense.

113. The Commission concludes that the appropriate pro forma level of amortization of bond defeasance gain under present rates is $64,560.

114. Total pro forma operating revenue deductions under present rates is the sum of the various pro forma expenses under present rates discussed above.

115. The pro forma "cost of gas" is $211,707,096 as determined herein.

116. The pro forma "operation and maintenance expense" under present rates is $44,687,059 as determined herein.

117. The pro forma "depreciation expense" under present rates is $9,494,733 as determined herein.

118. The pro forma "general taxes" under present rates is $14,879,648 as determined herein.

119. The pro forma "state income taxes" under present rates is $1,401,835 as determined herein.

120. The pro forma "Federal income taxes" under present rates is $6,236,035 as determined herein.

121. The pro forma "amortization of investment tax credits" under present rates is $310,621 as determined herein.

122. The pro forma "interest on customer deposits" under present rates is $200,181 as determined herein.

123. The pro forma "amortization of bond defeasance gain" under present rates is $64,560 as determined herein.

124. The Company can reasonably expect to incur pro forma total operating revenue deductions under present rates of $288,231,406, based on the expected sale of 60,358,883 dts. of gas and an assumed commodity cost of gas of $3.4524.

125. The Commission concludes that the appropriate pro forma level of "total operating revenue deductions" under present rates is $288,231,406.

126. Net operating income for return is the result of subtracting total operating revenue deductions from total operating revenue.

127. Total operating revenue is $313,883,473.

128. Total operating revenue deductions are $288,231,406.

129. The Company can reasonably expect to earn net operating income for return of $25,652,067 under present rates.

130. The Commission concludes that the appropriate pro forma level of "net operating income for return" under present rates is $25,652,067.

131. The plant in service at the end of the test period is $358,593,604, consisting of the Company's filed number of $369,492,903 less agreed upon adjustments of $10,899,299.

132. The post-test period plant additions total $26,310,606.

133. It is appropriate to determine the plant in service by adding the end of test period plant in service of $358,593,604 to the $26,310,606 of plant additions which occurred after the end of the test period but before the close of the hearing.

134. In the absence of any evidence to the contrary, the appropriate gas utility plant in service for use in this case is $384,904,210.

135. The Commission concludes that the appropriate amount of gas utility plant in service to include in rate base is $384,904,210.

136. The Company had leasehold improvements, net at the end of the test period of $9,188.

137. No party offered any evidence to contest the Company's proposed inclusion of $9,188 of leasehold improvements, net in rate base.

138. In the absence of any evidence to the contrary, the appropriate amount to include in rate base for leasehold improvements, net is $9,188.

139. The Commission concludes that the appropriate pro forma leasehold improvements, net for use in this case is $9,188.

140. The accumulated depreciation at the end of the test period was $87,934,935, consisting of $88,146,701 proposed by the Company less $211,766 associated with the removal of $10,899,299 of plant in service discussed above.

141. The accumulated depreciation associated with plant additions is $1,540,163 [$89,475,098 - $87,934,935].

142. The Commission finds that accumulated depreciation at the end of the test period should be reduced by $211,766 to reflect agreed upon reductions in plant in service at the end of the test period.

143. The Commission finds that end of test period accumulated depreciation should be increased by $1,540,163 to reflect post-test period plant additions.

144. In the absence of any evidence to the contrary, the appropriate amount accumulated depreciation is $89,475,098.

145. The Commission concludes that the appropriate amount of accumulated depreciation to include in rate base is $89,475,098.

146. The Company had customer advances for construction at the end of the test period of $694,240.

147. No party offered any evidence to contest the Company's proposed inclusion of $694,240 of customer advances for construction.

148. In the absence of any evidence to the contrary, the appropriate amount to include in rate base for customer advances for construction is $694,240.

149. The Commission concludes that the appropriate level of customer advances for construction is $694,240.

150. Net plant in service is the sum of gas utility plant in service, net leasehold improvements, less accumulated depreciation and customer advances for construction.

151. Gas utility plant in service is $384,904,210.

152. Leasehold improvements, net are $9,188.

153. Accumulated depreciation is $89,475,098.

154. Customer advances for construction are $694,240.

155. The appropriate net plant in service for use in this case is $294,744,060.

156. The Commission concludes that the appropriate net plant in service is $294,744,060.

157. The Company and the Public Staff have stipulated to a working capital allowance of $12,735,494.

158. No party other than the Company and the Public Staff offered any evidence with respect to working capital allowance.

159. In the absence of any evidence to the contrary, the appropriate working capital allowance is the working capital allowance agreed to by the Company and the Public Staff in the stipulation.

160. The Commission concludes that the appropriate allowance for working capital is $12,735,494.

161. The appropriate level of accumulated deferred income taxes as agreed to by the Company and the Public Staff is $31,772,011.

162. No party other than the Company and the Public Staff offered any evidence on this issue.

163. In the absence of any evidence to the contrary, the appropriate going level of accumulated deferred taxes is the amount agreed to by the Company and the Public Staff in the stipulation.

164. The Commission concludes that the appropriate going level of pro forma accumulated deferred taxes is $31,772,011.

165. The appropriate level of cost-free capital as agreed to by the Company and the Public Staff in the stipulation is $1,205,326.

166. No party other than the Company and the Public Staff offered any evidence on this issue.

167. In the absence of any evidence to the contrary, the appropriate going level of cost-free capital is the amount agreed to by the Company and the Public Staff in the stipulation.

168. The Commission concludes that the appropriate going level of cost-free capital is $1,205,326.

169. The appropriate level of unamortized gain on bond defeasance as agreed to by the Company and the Public Staff is $59,188.

170. No party other than the Company and the Public Staff offered any evidence on this issue.

171. In the absence of any evidence to the contrary, the appropriate going level of unamortized gain on bond defeasance is the amount agreed to by the Company and the Public Staff in the stipulation.

172. The Commission concludes that the appropriate going level of unamortized gain on bond defeasance is $59,188.

173. Original cost rate base is the sum of net plant in service plus a reasonable allowance for working capital less accumulated deferred taxes, cost-free capital and unamortized gain on bond defeasance.

174. The amount of each of the components of rate base is set forth above.

175. G.S. 62-133(b)(1) requires the Commission to ascertain the reasonable original cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period, in providing the service rendered to the public within North Carolina, less that portion of the cost which has been consumed by previous use recovered by depreciation expense.

176. In determining the original cost of a public utility's property, the Commission is required to consider such relevant, material and competent evidence as may be offered by any party tending to show actual changes in the cost of the public utility's property which is based upon circumstances and events occurring up to the time the hearing is closed. G.S. 62-133(c).

177. The $274,443,029 rate base is used and useful, or will be used and useful within a reasonable time after the test period, in providing public utility service in North Carolina.

178. The Commission concludes that the appropriate rate base for use in this case is $274,443,029.

179. Net operating income for return is $25,652,067.

180. Rate base is $274,443,029.

181. When $25,652,067 is divided by $274,443,029, the result is 9.35%.

182. Return on rate base is determined by dividing net operating income for return by rate base.

183. The Commission concludes that the return on rate base under present rates is 9.35%.

184. The 52% common equity ratio adopted herein is within the Moody's companies' average for the past four years and within the range of Piedmont's common equity ratio within the past several years.

185. In the stipulation, the Company and the Public Staff agreed to a capital structure consisting of 46% long-term debt, 2% short-term debt and 52% common equity.

186. No party other than the Company and the Public Staff offered any evidence on the appropriate capital structure.

187. The levels of long-term debt, short-term debt and common equity adopted for use herein are reasonable.

188. The Commission concludes that the appropriate capital structure for use in this proceeding is as follows:

Item	Percent
Long-term debt	46.00
Short-term debt	2.00
Common equity	52.00
Total	100.00

189. The appropriate cost of long-term debt as agreed to by the Company and the Public Staff in the stipulation is 9.9%.

190. No party other than the Company and the Public Staff offered any evidence on this issue.

191. In the absence of any evidence to the contrary, the appropriate cost of long-term debt is the amount agreed to by the Company and the Public Staff in the stipulation.

192. The Commission concludes that the appropriate cost of long-term debt for use in this proceeding is 9.9%.

193. The appropriate cost of short-term debt as agreed to by the Company and the Public Staff in the stipulation is 8.5%.

194. No party other than the Company and the Public Staff offered any evidence on this issue.

195. In the absence of any evidence to the contrary, the appropriate cost of short-term debt is the amount agreed to by the Company and the Public Staff in the stipulation.

196. The Commission concludes that the appropriate cost of short-term debt for use in this proceeding is 8.5%.

197. The return on common equity under existing rates is mathematically determined by dividing the net operating income left over after the payment of interest on long-term and short-term debt by the common equity portion of the rate base.

198. The various components of this mathematical determination, which are set forth in the table below, were agreed to by the Company and the Public Staff in the stipulation.

199. The pro forma return on common equity under present rates is 8.89%.

200. The Commission concludes that the pro forma return on common equity under present rates is 8.89% as shown in the following table:

Type of Capital	Rate Base	Ratio %	Embedded Cost/Return Percentage	Net Operating Income
Long-Term Debt	$126,243,793	46.00%	9.90%	$12,498,136
Short-Term Debt	5,488,861	2.00%	8.5%	466,553
Common Equity	142,710,375	52.00%	8.89%	12,687,378
Total	$274,443,029	100.00%		$25,652,067

201. The Company and the Public Staff agreed in the stipulation to a return on common equity of 12.9%. No other party presented any evidence on the appropriate return on common equity.

202. Company witness Murry recommended a return on common equity of 14% to 14.5% to which should be added 50 basis points above the mid-point to provide an adequate cushion for the Company to earn its allowed return in normal circumstances.

203. Public Staff witness Sessoms recommended a return on common equity of 12.52%, including a "flotation" or financing cost of .12%.

204. Company witness Murry's DCF analyses produce cost of equity capital for Piedmont ranging from a low of 11.75% to a high of 16.2%.

205. Public Staff witness Sessoms' DCF analyses produce cost of equity capital for Piedmont ranging from a low of 12.3% to a high of 12.6% and a cost of equity capital for comparable companies ranging from a low of 11.8% to a high of 12.4%.

206. Company witness Murry testified that the DCF calculations produce the basic, marginal cost of common equity for the Company and that a cushion is needed to give the Company a reasonable opportunity to earn the allowed return.

207. Piedmont is continuously adding new plant to better serve its customers and must be in a position to raise new capital. Piedmont expects to sell in excess of $100 million of long-term securities in 1991.

208. Combining a return on common equity of 12.9% with the capital structure, cost of short-term debt and cost of long-term debt heretofore determined to be appropriate yields an overall return of 11.43% to be applied to the Company's rate base.

209. The determination of the appropriate fair rate of return for the Company is of great importance and must be made with great care because whatever return is allowed will have an immediate impact on the Company, its shareholders and its customers.

210. In the final analysis, the determination of a fair rate of return must be made by this Commission, using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record.

211. Whatever return is allowed must balance the interest of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4):

> ". . . (to) enable the public utility by sound management to produce a fair return for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its customers and to its existing investors."

212. The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b):

> ". . . supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States . . " State ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 277, 206 S.E.2d 269 (1974).

213. The Commission must use its impartial judgment to ensure that all parties involved are treated fairly and equitably.

214. It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 S.E. 2d 547 (1980). Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E.2d 786 (1982).

215. The determination of the appropriate rate of return is not a mechanical process and can be made only after a study of the evidence based upon careful consideration of a number of different methodologies weighted and tempered by the Commission's impartial judgment.

216. The determination of rate of return in one case is not res judicata in succeeding cases. Utilities Commission v. Power Co., 285 N.C. 377, 395 (1974).

217. The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." Utilities Commission v. Public Staff, 322 N.C. 689, 694, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made in each case based on the evidence presented (and the weight and credibility thereof).

218. The Commission concludes that, under the facts and circumstances of this case, great weight should be given to the return on common equity stipulated by the Company and the Public Staff. These are the only two parties to introduce direct testimony on the appropriate rate of return. Both of these parties produced witnesses who had conducted DCF studies to support their recommended returns on common equity.

219. The Commission concludes that it should give weight to the fact that Piedmont is continuously adding new plant to better serve its customers, that Piedmont must be in a position to raise new capital and that Piedmont expects to sell in excess of $100 million of long-term securities in 1991.

220. It is appropriate to include a "flotation" or financing cost in the return on equity because of the Company's need to raise additional capital in 1991.

221. A "flotation" or financing cost of .12% is reasonable in view of the similar cost experienced by the Company in the last ten years.

222. A return on common equity of 12.9% and a return on rate base of 11.43% will enable the Company by sound management to produce a fair rate of return for its shareholders, to maintain facilities and services in accordance with the reasonable requirements of its customers and to compete in the capital market for funds on terms which are reasonable and fair to the Company's customers and existing investors.

223. The Commission cannot guarantee that the Company will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if we could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency.

224. The Commission concludes that the appropriate cost of common equity for use in this proceeding is 12.9%, including a "flotation" or financing cost of .12%.

225. The amounts set forth in the "Increase Approved" and "After Increase Approved" columns of Schedules I and II and under "Approved Rates" in Schedule III hereinafter set forth in the discussion of evidence below are matters of mathematical computation which have been agreed to by the Company and the Public Staff in the stipulation.

226. The amounts set forth in the columns "Benchmark Cost of Gas Change" and "After Change In Benchmark Cost of Gas" in Schedule I reflect the change from a $3.4524 benchmark cost of gas to a $2.50 benchmark cost of gas and are also matters of mathematical computation which have been agreed to by the Company and the Public Staff in the stipulation.

227. Additional revenues of $9,664,433 will provide the Company with the opportunity to earn the returns found appropriate herein.

228. The Commission concludes that the Company will require additional annual revenues of $9,664,433 to earn the returns found appropriate herein.

229. The heating-only classification was established in an attempt to charge the low load factor heating-only consumer the cost of providing the more expensive winter peaking gas services and supplies.

230. Many commercial heating-only customers qualify for the year-around schedule by adding a small gas appliance such as a gas light or small water heater which uses an insignificant amount of gas when compared to the large winter heating load.

231. Under the facts of this case, the separate Rate 102 heating-only rate is not the best method of charging the low load factor heating-only consumer the cost of providing the more expensive winter peaking gas services and supplies.

232. Under the facts of this case, it is appropriate to recognize the cost associated with a heating-only customer through use of the summer-winter rate differential

233. The Commission concludes that the existing Rate Schedule 102 Heating-Only should be eliminated.

234. The Company has only ten customers on Rate Schedule 102 Air Conditioning.

235. The ten customers presently on Rate Schedule 102 Air Conditioning can best be served under the proposed Rate Schedule 102.

236. The Commission concludes that the existing Rate Schedule 102 Air Conditioning should be eliminated.

237. Rate Schedule 102 customers pay higher rates because they use less than 50 dts. per day.

238. The 50 dts. per day threshold was established during curtailment days and has no significant relationship to the cost of serving customers.

239. A number of complaints have been filed with the Commission by customers contending that they have been placed on the wrong rate schedule.

240. Under the facts of this case, differences in rates for size distinctions are best handled through step rates which allow for gradual price differential based on size.

241. If the rates are the same for Rate 102 and Rate 103, no customer will be disadvantaged by being placed on the wrong rate schedule.

242. The Commission concludes that the rates for Rate Schedules 102 and 103 should be step rates and that the rates should be the same for both rate schedules.

243. The rates stipulated to by the Company and the Public Staff will produce an overall increase of slightly more than 3%, consisting of approximately 3.9% to residential customers, approximately 1.3% to the small general service customers, approximately 7% to the large general service customers and approximately 1% to other interruptible customers.

244. Under the rates stipulated to by the Company and the Public Staff, the large general service transportation customers will receive a decrease of approximately 5% in their rates and the interruptible transportation customers will receive a minor decrease in their rates.

245. Under existing rates, high priority customers already pay a much higher rate per unit of gas than industrial customers purchasing gas under Rate Schedules 103 and 104.

246. Rate Schedule 103 and 104 customers can and do switch to alternate fuels when the price of alternate fuels is less than the price of natural gas.

247. The Commission has examined the various cost of service studies and has concluded that while they are an important and relevant guide or factor to be weighed in designing rates in this proceeding, they reflect a great deal of subjective judgment on the part of the person conducting the study and, therefore, cannot be blindly followed.

248. The Supreme Court of North Carolina has also noted that factors other than cost of service should be considered in setting utility rates. In Utilities Commission v. N.C. Textile Manufacturers Assoc., 313 N.C. 215, 222, 238 S.E.2d 264, 269 (1985), the Court held:

> "In determining whether rate differences constitute unreasonable discrimination, a number of factors should be considered: '(1) quantity of use, (2) time of use, (3) manner of service, and costs of rendering the two services.' Utilities Comm. v. Oil Col., 302 N.C. 14, 23, 273 S.E.2d 232, 238 (1980). Other factors to be considered included 'competitive conditions, consumption characteristics of the several classes and the value of service to each class, which is indicated to some extent by the cost of alternate fuels available.' Utilities Comm. v. City of Durham, 282 N.C. 308, 314-15, 193 S.E.2d 95, 100 (1972)."

249. The Supreme Court examined this matter again in State ex rel. Utilities Commission v. Carolina Utility Customers Association, 323 N.C. 238, 372 S.E.2d 692 (1988). In this case, CUCA and other parties challenged the Commission's decision in a North Carolina Natural Gas Corporation (NCNG) general rate case that the differences in rates of return among NCNG's various customer classes were not unreasonably discriminatory nor unjust and unreasonable. The Court found that the Commission had made adequate findings and conclusions and that the Commission had drawn "legitimate distinctions" which justify maintaining large industrial rates of return at a higher level than residential, commercial, and small industrial rates of return. The Court held, "While an assessment of the Commission's Order based simply on the cost of service evidence might suggest the adopted rates are unreasonably discriminatory, the Commission's analysis of the non-cost factors permitted in our case law is sufficient to justify the Commission's decision." Id at 252.

250. The Supreme Court examined this matter most recently in Utilities Commission v. Carolina Utility Customers Association, 328 N.C. 37, 399 S.E. 2d 98 (1991). In this case, the Court once again held that the Commission did not have to establish rates based solely on cost of service considerations.

251. It is not reasonable to adopt the goal of solely cost-based rates and equalized rates of return among customer classes.

252. Fully equalized returns would place an unreasonable burden on residential customers relative to their historical rates. The effect of equalized returns, even if achieved over three rate cases, would be traumatic to Rate Schedule 101 because these customers, unlike many lower priority customers, cannot easily switch fuels. At the time Rate Schedule 101 customers bought their heating plants, their gas rates looked relatively attractive compared to how they would look under equalized returns, and the long-established expectations of these customers should be taken into consideration.

253. Rate Schedule 101 customers pay the highest unit price rates and, therefore, contribute a disproportionately large share of the Company's revenue requirement relative to the volumes they use. It would be unjust and unreasonable to place any greater amount of the increase on the residential customers at this time than that approved herein.

254. Although the cost of service studies show that the Company earns a higher return on the sale of gas to its industrial customers, Piedmont's rates to these customers have decreased over the years.

255. Because cost of service studies are highly judgmental, they should be considered as only one among many factors in rate design. Non-cost factors such as those listed above must also be considered.

256. Rates of return between customer classes, as shown on cost of service studies, are not directly comparable. Large industrial customers do not always pay the rates approved, as assumed in cost of service studies. Piedmont has the right to, and does, negotiate rates for these customers in order to meet alternative fuel prices. This ability to negotiate lower rates gives these industrial customers a bargaining power unavailable to residential and small general service customers and increases the risk to the Company. This justifies a higher rate of return relative to residential and small general service customers. This bargaining power has resulted in lower priority customers paying millions of dollars less in revenues than contemplated in the cost of service studies, which assume full margin tariff rates.

257. Rates of return are not comparable for another reason. The lower priority "fuel switchable" customers pose greater financial risk because they can leave the system, causing Piedmont substantial loss of sales. The degree of this risk is a function of alternative fuel prices. Therefore, it is important that Piedmont be able to negotiate gas prices below the tariff rate when alternative fuel prices are low, in order to lessen the risk of losing customers. It is equally important that the tariff rate be set so as to result in a return being paid by these customers when alternative fuel prices are high that will compensate Piedmont for the higher risks of these customers.

258. Rate design must give appropriate weight to value of service, to the consumption characteristics of large industrial customers and to competitive conditions. If the rates are not competitive with alternate fuels, the Company would be unable to sell its gas to fuel switchable customers and the remaining

captive customers would have their rates increased because they would have to pay the fixed costs now being paid by fuel switchable customers.

259. Rate design must give appropriate weight to the quantity of use. Large industrial customers pay "step rates" with declining blocks. Under these rates, the unit price goes down as consumption goes up, reflecting the reduced per unit cost of providing service to larger users.

260. The Commission concludes that it is appropriate to consider a number of factors when designing rates, including cost of service, value of service, quantity of natural gas used, the time of use, the manner of use, the equipment which the Company must provide and maintain in order to meet the requirements of its customers, competitive conditions and consumption characteristics. The Commission also concludes that it would be unjust and unreasonable to establish rates in this proceeding based solely upon equalized rates of return for all customer rate classes.

261. The Commission has considered the use of full margin transportation rates on many occasions in the past and has each time determined such rates to be appropriate.

262. Regardless of whether the service is rendered under Rate 103 or 113 or under Rate 104 or 114, (1) the gas passes through the same pipes, meters and regulators, (2) Piedmont provides the same load balancing and use of storage, (3) the same employees perform the billing services, (4) there is no difference to customers in the value of the service received, (5) the use by the customers is the same and (6) their consumption characteristics are the same.

263. Piedmont acquires gas for its transportation customers so it can provide them gas when transportation gas supply is not available.

264. When Piedmont transports customer-owned gas, Piedmont must deal with the producer selling that gas, the pipeline transporting the gas and the various regulatory agencies who must approve the transaction.

265. The Commission continues to find no justification for a difference between the margins earned on the Company's sales rate schedules and its transportation rate schedules.

266. The Commission concludes that the services performed by Piedmont are substantially the same whether service is provided under the sales rate or transportation rate.

267. The Commission concludes that full margin transportation rates are just and reasonable.

268. The current charge for reconnecting a customer's service is not sufficient to cover the costs involved in providing this service.

269. Only about 5% of Piedmont's North Carolina customers had reconnects during the test period.

270. The proposed reconnection charges will more nearly pay the costs of the reconnection services performed by the Company.

271. It would not be fair and reasonable, under the facts of this case, for the 95% of customers who are not provided reconnection services to subsidize the 5% of customers who do use the services.

272. The Commission concludes that the reconnection fees proposed by Piedmont and approved herein are just and reasonable.

273. The rates stipulated to by the Company and the Public Staff will produce an overall increase of slightly more than 3%, consisting of approximately 3.9% to residential customers, approximately 1.3% to the small general service customers, approximately 7% to the large general service customers and approximately 1% to other interruptible customers.

274. Under the rates stipulated to by the Company and the Public Staff, the large general service transportation customers will receive a decrease of approximately 5% in their rates and the interruptible transportation customers will receive a minor decrease in their rates.

275. The rates approved in this proceeding result in a fair distribution of the overall rate increase granted to Piedmont among customer classes and it would be unjust and unreasonable, based upon the evidence presented in this case, to shift any greater rate increase to the residential and small general service customers served by Piedmont who are already paying and will continue to pay the highest unit price rates on the system.

276. The rates approved in this proceeding will generate the appropriate level of revenues and will afford Piedmont an opportunity to achieve the approved overall rate of return of 11.43%.

277. The Commission concludes that the rates set forth in Late Filed Schedule V Revised Corrected and approved herein are just and reasonable, do not result in any unjust or unreasonable discrimination or preference between or within classes of customers and should be approved.

278. No party offered any evidence in opposition to the proposed changes in tariff language.

279. The changes in tariff language clarify the intent of the tariffs.

280. The Commission concludes that the changes in tariff language proposed by the Company are fair and reasonable.

281. No party offered any evidence in opposition to the proposed changes in the language of the service regulations.

282. The changes in the language clarify the intent and purposes of the service regulations and the obligations of the Company and its customers and should be approved.

283. The Commission concludes that the language of the service regulations agreed to by the Company and the Public Staff is fair and reasonable and should be approved except as to the extent they relate to the PGA provisions which are discussed elsewhere herein.

284. The Commission approved a Purchased Gas Adjustment (PGA) Clause for Piedmont by Order of February 13, 1990, in Docket No. G-9, Subs 289, 291, and 296. The Commission prohibited the recovery of demand and storage charges incurred in connection with additional pipeline capacity, except for certain specified charges which were allowed as part of a compromise between Piedmont and the Public Staff.

285. The revised PGA Clause proposed by Piedmont in this case accounts for all commodity costs of all gas supplies and service and for all fixed costs of gas of all supplies and services, including the costs of additional pipeline capacity and storage. The proposed revised PGA Clause provides for a 100% true-up of all prudently incurred gas costs.

286. Piedmont asks the Commission to approve the proposed revised PGA Clause pursuant to the Commission's general authority to approve ratemaking formulas in a context of a general rate case. See Utilities Commission v. NCNG, 323 N.C. 630, 375 S.E.2d 147 (1989); Utilities Commission v. CF Industries, 299 N.C. 504, 263 S.E.2d 559 (1980); Utilities Commission v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976); Utilities Commission v. Public Service Company, 35 N.C. App. 156, 241 S.E.2d 79 (1978).

287. On July 8, 1991, the General Assembly enacted Chapter 598 of the 1991 Session Laws. This legislation amends Chapter 62 of the General Statutes by adding G.S. 62-133.4. This new statute authorizes the Commission to allow rate changes "occasioned by changes in the cost of natural gas supply and transportation. . . " The new statute also provides for an annual review to "compare the utility's prudently incurred costs with costs recovered from all the utility's customers that it served during the test period." If prudently incurred costs are greater or less that recovered costs, the Commission shall require the utility to refund any overrecovery or permit the utility to recover any deficiency. Finally, the new statute provides that the "costs" subject to the statute shall be "defined by Commission rule or order and may include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system."

288. The Commission will initiate proceedings, separate from this general rate case, in the near future, in order to define "costs" for purposes of G.S. 62-133.4 and in order to provide for implementation of G.S. 62-133.4.

289. To avoid any gap between the operation of Piedmont's old PGA Clause and implementation of the new statute G.S. 62-133.4, the Commission approves the revised PGA Clause proposed by Piedmont in this case. This approval shall be provisional in the sense that the Commission recognizes that the revised PGA Clause may be superceded by the procedures adopted to implement G.S. 62-133.4. The costs subject to the provisional revised PGA Clause which relate to additional pipeline capacity and storage shall be subject to the Commission's

determination of which costs shall be subject to the rate changes and true-up provided by G. S. 62-133.4. Any monies so collected which are associated with additional pipeline capacity and storage shall be placed in a deferred account pending further Order of the Commission.

290. Provisional approval of the revised PGA Clause as proposed by Piedmont to include the costs of additional pipeline capacity and storage is made without prejudice to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G.S. 62-133.4.

291. Fixed costs and storage charges should be recovered through the revised PGA Clause on an equal volumetric basis from all customers for the reasons set forth above in the discussion of rate design.

292. The Commission concludes that the revised PGA Clause proposed by the Company should be approved on a provisional basis, as hereinabove provided, pending implementation of G. S. 62-133.4.

293. Piedmont and the Public Staff resolved their difference as to the pro formal level of unaccounted-for volumes by stipulation. Although the Public Staff stipulated to use of the unaccounted-for volumes recommended by Piedmont, the Public Staff recommended an annual true-up of the unaccounted-for volumes.

294. Piedmont agreed to a true-up of unaccounted-for volumes if its revised PGA Clause was approved. The Commission has hereinabove approved the revised PGA Clause on a provisional basis pending implementation of G.S. 62-133.4.

295. The Commission therefore concludes that the true-up of unaccounted-for natural gas volumes should be approved on a provisional basis pending implementation of G. S. 62-133.4 and that Piedmont shall adopt deferred accounting with respect to the true-up of such volumes.

296. The Company's earnings and rates of return and customers' bills can vary widely due to departures from normal weather.

297. Piedmont's winter period in its rate schedules is the five months of November through March.

298. Eighty-seven percent of the degree days occur during this five-month period.

299. Some Rate Schedule 103 customers are weather sensitive.

300. The Weather Normalization Adjustment (WNA) Clause will reduce variations in the Company's earnings and rates of return and in customers' bills.

301. The WNA Clause will protect both the Company and its customers from the adverse impact of departures from normal weather.

302. The WNA Clause will increase bills when customers can best absorb the adjustment during warm weather when consumption is low and will reduce bills during extremely cold periods when consumption is high.

303. The months of November through March should be included in the WNA Clause to match the winter period of Piedmont's rates.

304. Rate Schedule 103 should be included in the WNA Clause because some of the gas used under that rate schedule is weather sensitive.

305. For purposes of the WNA Clause, fixed gas costs will be allocated to the various customer classes as set forth in Schedule IV attached to the stipulation entered into between the Company and the Public Staff.

306. The Commission concludes that the WNA Clause as agreed to by the Company and the Public Staff in the stipulation is fair and reasonable and should be approved.

307. The Company and the Public Staff stipulated to the use of a 10% interest rate, which is to be compounded monthly, for the interest to be applied to deferred account No. 253.

308. No other party introduced any evidence on this issue or questioned the use of the 10% interest rate.

309. In the absence of any evidence to the contrary, the interest rate to be applied to deferred account No. 253 agreed to by the Company and the Public Staff represents a fair and reasonable interest rate at this time.

310. The Commission concludes that a 10% interest rate, which is to be compounded monthly, is reasonable at this time for the interest to be applied to deferred account No. 253.

311. The Company and the Public Staff stipulated to the use in this proceeding of a pro forma commodity cost of gas and initial benchmark cost of gas of $2.50 per dekatherm and that the Company can increase its benchmark price in the manner set forth in Section II A of the PGA Clause.

312. No other party introduced any evidence on this issue or questioned the use of the $2.50 cost of gas for these purposes.

313. In the absence of any evidence to the contrary, the use of a pro forma commodity cost of gas and initial benchmark cost of gas of $2.50 per dekatherm agreed to by the Company and the Public Staff is fair and reasonable.

314. The Commission concludes that the pro forma commodity cost of gas and initial benchmark cost of gas to be used in this proceeding is $2.50 per dekatherm and that the Company can increase its benchmark price in the manner set forth in Section II A of the PGA Clause. Further, with respect to the true-up of the commodity cost of gas, Piedmont shall initially use the $2.50 per dekatherm as the benchmark cost of gas.

315. The Company and the Public Staff stipulated that Piedmont would conduct a study of deferred tax reserves as recommended by the Public Staff and that the study would be completed by the time of the filing of Piedmont's next general rate case or within two years, whichever occurs later.

316. No other party introduced any evidence on this issue.

317. In the absence of any evidence to the contrary, it is appropriate for Piedmont to conduct a study of deferred tax reserves as recommended by the Public Staff and that the study be completed by the time of the filing of Piedmont's next general rate case or within two years, whichever occurs later.

318. The Commission concludes that Piedmont should conduct a study of deferred tax reserves as recommended by the Public Staff and that the study should be completed by the time of the filing of Piedmont's next general rate case or within two years, whichever occurs later.

319. The Company and the Public Staff stipulated that Piedmont would file monthly reports in the form set forth in Exhibit II to Public Staff witness Hoard's prefiled testimony and that these monthly reports would be in lieu of the quarterly reports Piedmont currently files with the Commission unless the Commission or the Commission Staff objects to discontinuing the filing of quarterly reports. The Public Staff proposed monthly reports in order to better monitor Piedmont.

320. No other party introduced any evidence on this issue.

321. The Commission uses the quarterly information reported by Piedmont and objects to discontinuing the filing of the quarterly reports.

322. The frequency and content of reports appropriate to monitor implementation of G.S. 62-133.4 should be determined in separate proceedings as the Commission implements that statute.

323. The Commission concludes that Piedmont should continue to file quarterly reports for the present, subject to determination of the appropriate reporting for implementation of G.S. 62-133.4.

The evidence in support of the above findings and conclusions is as follows:

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 1-7

The Company filed a verified application on December 21, 1990, seeking, among other things, an increase in its jurisdictional rates and charges. The application was accompanied by the testimony and exhibits of various witnesses and N.C.U.C. Form G-1. On April 16, 1991, the Company filed affidavits of publication stating that notice of the hearing was published in various newspapers in the Company's service area as required by the Commission's order of January 18, 1991. In its verified application, the Company stated that it is incorporated under the laws of the State of New York and that it is duly domesticated and is engaged in the business of transporting, distributing and selling gas in 42 North Carolina communities. [Application, p. 2, ¶ II]. Company witness Maxheim testified that the Company serves approximately 247,000 gas customers in North Carolina. [T. Vol. 3, p. 57].

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 8-11

The Company filed its application and exhibits using a test period of the twelve months ended October 31, 1990, updated to reflect estimated increases in certain expense and plant items and changes in capitalization through June 30, 1991. [T. Vol 6, pp. 116, 127]. In its suspension order of January 18, 1991, the Commission ordered the parties to use a test period consisting of the twelve months ended October 31, 1990, with appropriate adjustments. [Order of January 18, 1991, p. 2, ¶ 5]. For the most part, the Public Staff used a test period ended October 31, 1990, updated for certain items of expense and plant through March 31, 1991. [T. Vol. 6, pp. 116, 127]. At the hearing and in the stipulation, the Company acquiesced to the updated period proposed by the Public Staff.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 12-14

Company witness Maxheim testified that the Company is presently adding customers at four times the national average and expects to continue adding customers at the same level for the next five years. [T. Vol. 3, pp. 58, 91]. At the public hearing in Charlotte, public witness Hancock testified that Piedmont provides assistance to Habitat for Humanity, a builder of low-income housing, and public witness Schuster testified that Piedmont has provided natural gas service to every one of the subdivisions built by Squires Homes during the past thirteen years and that gas was the preferred fuel for his homebuyers. [T. Vol. 1, pp. 3-8]. At the public hearing in Greensboro, public witness Lowdermilk testified that Piedmont has demonstrated a positive attitude toward community service and concern for cost effectiveness in operations and expansions, public witness Lynch testified that Piedmont is responsive to the needs of the business community and public witness Stapleton testified that Piedmont has always been a responsive company to provide very important natural gas services to the industrial sector. [T. Vol. 2, pp. 2-9]. At the hearing in Raleigh, public witness Myers testified that Piedmont provides good service. [T. Vol. 3, p. 4].

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION 15

On February 8, 1990, in Docket No. G-9, Subs 289, 291 and 296, the Commission approved procedures which permit Piedmont to recover increases in its wholesale gas costs. On October 31, 1990, in Docket No. G-9, Subs 300 and 306, the Commission authorized Piedmont to increase its rates by $.0409 per dekatherm to recover one-half of the increase in Piedmont's wholesale cost of gas relating to Transco's Southern Expansion project. On November 21, 1990, in Docket No. G-9, Sub 308, the Commission authorized Piedmont to increase its rates by $.0212 per dekatherm to recover its increased wholesale cost of gas relating to the purchase of gas from Columbia. All three of the above referred to orders have been appealed to the North Carolina Court of Appeals.

In its application, the Company requested the Commission to reapprove the PGA Clause as approved in Docket No. G-9, Subs 289, 291 and 296, on an interim basis pending its final order in this docket. The Company asserted that the requested interim relief would provide additional authority for Piedmont to collect the amounts previously authorized by the Commission. The Company also requested the Commission to reapprove the PGA Clause as approved in Docket No. G-9, Subs 289, 291 and 296, on an interim basis pending its final order in this docket.

On January 25, 1991, the Commission heard oral arguments on Piedmont's request for interim relief. At that time, arguments were presented by Piedmont, the Public Staff and CUCA.

On February 5, 1991, the Commission issued its Order Allowing Interim Relief based on the reasoning stated therein.

EVIDENCE IN SUPPORT OF FINDING AND CONCLUSION 16

The evidence supporting this finding is contained in the supplemental testimony and related exhibits of Piedmont witness Maxheim. In addition, the other Piedmont witnesses and the Public Staff witnesses indicated at the time they introduced their prefiled testimony and exhibits that they assented to the stipulation and that the stipulation should supersede their prefiled positions.

Neither the Attorney General nor CUCA joined in the stipulation. The Commission received the stipulation in evidence, but the Commission proceeded with the hearing in order to allow all parties an opportunity to be heard. The Commission has considered the stipulation along with all other testimony and exhibits received at the hearing. The Commission has weighed the terms of the stipulation in the context of the entire record, and the Commission has proceeded to determine the Company's rates under the standards of G.S. 62-133 and other applicable statutes on the basis of the entire record. See generally, Mobil Oil Corporation v. Federal Power Commission, 417 U.S. 283, 312-314, 94 S. Ct. 2328, 2348, 41 L. Ed. 2nd 72, 97-98 (1974).

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 17-38

Company witness Guy offered evidence that actual "operating revenues from the sale and transportation of gas" during the test period were $214,653,231. [Exhibit BLG-1, Schedule 7, Page 1]. The Company proposed to adjust actual test period data to annualize for conditions that changed from time to time during the test period, to normalize for weather, to provide for growth in sales and to reflect for the fact that not all volumes are sold at fixed rates. [T. Vol. 5, pp. 6-9]. After these adjustments, the Company's proposed pro forma "operating revenues from the sale and transportation of gas" under present rates is $302,881,585, assuming a $3.4524 commodity cost of gas. [Exhibit CWF-1].

The Public Staff also proposed to adjust actual test period data to annualize for conditions that changed from time to time during the test period, to normalize for weather, to provide for growth in sales and to reflect the fact that not all volumes are sold at fixed rates. After these adjustments, the Public Staff's proposed pro forma "operating revenues from the sale and transportation of gas" under present rates is $313,139,903, assuming a $3.4524 commodity cost of gas. [Curtis Exhibit A, p. 2]. This revenue would increase to $313,347,849 to reflect additional growth reflected in witness Curtis' revised testimony. [T. Vol. 6, pp. 168-169].

Public Staff witness Curtis testified that the difference between the pro forma revenue from the sale and transportation of gas as proposed by the Company and as proposed by the Public Staff results from the different volumes of gas used by them to calculate revenue. [Curtis, T. Vol. 6, pp. 145-150].

The Company offered evidence that actual test period volumes were 56,836,104 dts. [Exhibit CWF-1]. No other party offered any evidence on actual test period volumes.

Company witness Fleenor testified that actual test period volumes should be adjusted to annualize the conditions which existed from time to time during the test period to those conditions which existed at the end of the test period. These adjustments consist of reclassification of customers to and from Rate 102 and Rate 103 in accordance with tariff descriptions and certain modifications in contracts with gas suppliers. [T. Vol. 5, p. 6]. This adjustment results in the addition of 1,466,712 dts. [Exhibit CWF-1]. The Public Staff accepted this adjustment and no other party offered any evidence with respect to this adjustment.

Company witness Fleenor testified that the actual test period volumes should be adjusted to reflect volumes that would have been delivered had normal weather occurred during the test period. [T. Vol. 5, p. 6]. Although witness Fleenor adjusted sales to move sales from lower-priced industrial sales to higher-priced residential and commercial customers, he did not add any total volumes since he assumed that growth in sales to high priority customers would require a corresponding decrease in volumes delivered to industrial customers. [Exhibit CWF-1; T. Vol. 6, p. 145]. Public Staff witness Curtis agreed with the movement of volumes from industrial customers to residential and commercial customers; however, he testified that Piedmont could add sales to high priority customers without a corresponding decrease in volumes delivered to industrial customers. Public Staff witness Curtis testified that the Company has sufficient volumes to support both growth in sales to high priority customers and to maintain sales to industrial customers. [T. Vol. 6, p. 145-146].

Company witness Fleenor testified that the actual test period volumes should also be increased to reflect growth during the test period. [T. Vol. 5, p. 7]. Public Staff witness Curtis testified that test period volumes should be adjusted to reflect growth to March 31, 1991, in order to match revenues with plant. [T. Vol 6, pp. 146-147].

In the stipulation, the Company accepted the Public Staff's position with respect to both weather normalization and growth and no other party offered any evidence on these issues. [Exhibit JHM-2; T. Vol. 5, p. 18]. This agreement has the effect of increasing the actual test period volumes by 2,056,067 dts.

The Company and the Public Staff agreed that the application of these rates will produce pro forma test period revenue of $313,347,849. [Exhibit JHM-2]. This revenue was calculated using the revenue adjustment factors set forth in Exhibit CWF-1. These revenue factors were determined by comparing actual revenues during the test period with the revenues which would have been received had the Company collected its full tariff rates. This is the same method approved by the Commission in Piedmont's last rate case. [T. Vol. 5, p. 8]. Company witness Fleenor testified that the use of the revenue adjustment factors is necessary to adjust for the fact that the Company, for various reasons, does not receive its full tariff rates for all volumes sold. [T. Vol. 5, pp. 7-8]. The Public Staff agreed with the use of the revenue adjustment factors. No other party offered any evidence on the calculation of revenue or on the use of the revenue adjustment factor.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 39-41

Company witness Guy offered evidence that actual "other operating revenue" during the test period was $535,624. The Company did not propose any pro forma adjustments to "other operating revenue." No other party offered any evidence as to actual or pro forma "other operating revenue," and the Public Staff agreed with the Company's number in the stipulation.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 42-46

Total pro forma operating revenue under present rates is the sum of pro forma "operating revenue from the sale and transportation of gas" under present rates and pro forma "other operating revenue" under present rates. The evidence on both components of total operating revenue is set forth above. Additionally, in the stipulation, the Company and the Public Staff agreed that the appropriate pro forma level of "total operating revenue" under present rates is $313,883,473. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 47-57

Company witness Guy offered evidence that actual "cost of gas" during the test period was $122,675,243. [Exhibit BLG-1, Schedule 7, Page 1]. This "cost of gas" is based on actual volumes purchased and prices paid during the test period. The Company proposed to adjust actual test period data to reflect the changes in volumes discussed above and to reflect changes in rates. After these adjustments, the Company's proposed pro forma "cost of gas" under present rates is $205,467,628, assuming a $3.4524 commodity cost of gas. [Exhibit CWF-3].

The Public Staff also proposed to reflect the changes in volumes discussed above and to reflect changes in rates. After these adjustments, the Public Staff proposed pro forma "cost of gas" for North Carolina of $209,865,496, assuming a $3.4524 commodity cost of gas. [Curtis Exhibit D]. This cost of gas would increase to reflect additional growth reflected in witness Curtis' revised testimony. [T. Vol. 6, pp. 168-169].

Public Staff witness Curtis testified that the difference between the pro forma "cost of gas" as proposed by the Company and as proposed by the Public Staff results from the different volumes of gas used by them to calculate the "cost of gas," from changes in certain rates to reflect more current billings by interstate pipelines and from different allocations of joint fixed gas costs between North Carolina and South Carolina. [T. Vol. 6, pp. 150].

As stated above, the Company and the Public Staff agreed in the stipulation to volumes of 60,358,883 dts. Also, in the stipulation, the Company and the Public Staff agreed to changes in certain rates to reflect more current billings by interstate pipelines and on the method of allocation of joint fixed gas costs between North Carolina and South Carolina. [Exhibit JHM-2, p. 2]. More specifically, the Company and the Public Staff agreed on changes in various rates of Transcontinental Gas Pipe Line Corporation (Transco) and Columbia Gas Transmission Corporation (Columbia) based on current rates [Exhibit JHM-2, p. 2] and that 78% of the joint fixed gas costs should be allocated to North Carolina. [Exhibit JHM-2, p. 1-2].

The Company proposed to allocate 79.22% of joint fixed gas costs to North Carolina. [T. Vol. 5, p. 11; Exhibit CWF-3]. This percentage is based on the amount of gas delivered to North Carolina on the three-day peak during the test period. [T. Vol. 5, p. 11; T. Vol. 6, pp. 152-153]. The Public Staff proposed to allocate the fixed costs for various gas sources on different allocation methods. [T. Vol. 6, p. 153; Curtis Exhibit D]. These allocation factors result in a composite allocation of 76.85% of the fixed gas costs to North Carolina. [T. Vol. 6, p. 153]. In the Company's last North Carolina general rate case, Docket No. G-9, Sub 278, 78% of the fixed gas costs were allocated to North Carolina. [T. Vol. 6, p. 154].

Company witness Fleenor testified that most fixed gas costs are incurred primarily in providing service on peak days. [T. Vol. 5, pp. 12-15; Exhibit CWF-6]. Public Staff witness Curtis testified that some gas costs are incurred for peak days, some for winter service and some for annual service. [T. Vol. 5, p. 152; Curtis Exhibit D].

The Company and the Public Staff agreed in the stipulation that using the pro forma volumes previously found by us to be appropriate, a $3.4524 commodity cost of gas, current wholesale gas rates and a 78% allocation of fixed gas costs to North Carolina would result in a pro forma cost of gas of $211,707,096. [JHM-2, p. 5].

No party other than the Company and the Public Staff offered any evidence on the appropriate level of "cost of gas."

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 58-83

The Company offered evidence that actual "operation and maintenance expense" during the test period was $43,258,846. [Exhibit BLG-1, Schedule 7, p. 1]. The Company proposed accounting and pro forma adjustments of $2,765,760. These adjustments are detailed on Exhibit BLG-1, Schedule 7, p. 4.

Public Staff witness Hoard questioned the treatment of the following items in the Company's pro forma operation and maintenance expense: (1) regulatory fee, (2) uncollectibles, (3) merit pool increases occurring after March 31, 1991, (4) allocations of payroll to affiliates, (5) percentage of payroll applicable to operations, (6) advertising expense, (7) rate case expense, (8) insurance, (9) postage expense, (10) lobbying expense and (11) the amortization of the boiler fuel reserve account. [T. Vol. 6, pp. 126-132].

The Company included regulatory fees of $363,364 in its original filing. [Hoard Exhibit I, Schedule 3-2(a)]. The Company computed regulatory fees based on projected revenues assuming a $3.4524 per dekatherm commodity cost of gas. [T. Vol. 6, p. 126]. The Public Staff proposed regulatory fees of $257,738. [Hoard Exhibit I, Schedule 3-2(a)]. The Public Staff computed regulatory fees on per book revenues for the test period. [T. Vol. 6, p. 127]. In the stipulation, the Company and the Public Staff agreed to regulatory fees of $315,111. [Exhibit JHM-2, p. 3]. No other party offered any evidence on the calculation of regulatory fees. The stipulated regulatory fees were obtained by applying the statutory percentage (.12%) in effect at the time of the hearing to an agreed upon level of collectible revenues of $262,592,860.

The Company included uncollectibles of $614,244 in its original filing. [Hoard Exhibit I, Schedule 3-2(b)]. The Company computed uncollectibles based on projected revenues assuming a $3.4524 per dekatherm commodity cost of gas. [T. Vol. 6, p. 126]. The Public Staff proposed uncollectibles of $435,317. [Hoard Exhibit I, Schedule 3-2(b)]. The Public Staff computed uncollectibles on per book revenues for the test period. [T. Vol. 6, p. 127]. In the stipulation, the Company and the Public Staff agreed to uncollectibles of $533,364. [Exhibit JHM-2, p. 3]. No other party offered any evidence on the calculation of the uncollectibles expense. The stipulated uncollectibles expense was obtained by applying the ratio of net accounts charged off to revenues for the test year (.2028%) [Hoard Exhibit I, Schedule 3-2(b)] to an agreed upon level of revenues.

Public Staff witness Hoard testified that the Company had projected merit pool increases through June 30, 1991; whereas, the Public Staff had projected merit pool increases only through March 31, 1991. [T. Vol. 6, p. 127]. Witness Hoard also testified that the Company did not properly recognize the payroll allocations to affiliates in its payroll adjustment and that the Company had a mathematical error in its computation of the operation and maintenance expense payroll percentage. On rebuttal, Company witness Guy agreed with the Public Staff on these items; however, Mr. Guy replaced the merit pool March estimates with actual numbers for March. [T. Vol 3, p. 151]. In the stipulation, the Public Staff accepted the actual March numbers for the merit pool. [Exhibit JHM-2, p. 3, ¶ (n); T. Vol. 6, p. 138].

The Company proposed to increase actual test period advertising expense by $153,190. [T. Vol. 6, p. 129]. Company witness Maxheim testified that the present advertising policies of the Commission were adopted at the time when gas was in short supply and the State's gas utilities were discouraged from adding new customers; whereas, today there is an abundant supply of gas and the Company is adding customers at a rate that is four times the national average. [T. Vol. 3, p. 63]. Witness Maxheim testified that advertising would help the Company add new customers by advising potential customers of the availability of gas. [T. Vol. 3, p. 64]. He also testified that advertising benefits existing customers by providing more customers over whom certain fixed costs are spread. [T. Vol 3, p. 64]. On cross examination, Company witness Guy testified that he had made no attempt to determine whether any of the advertising dollars included in this case are or are not for "promotional" advertising. [T. Vol. 4, p. 6]. In his prefiled testimony, Public Staff witness Hoard objected to the inclusion of any promotional advertising expenses. [T. Vol. 6, pp. 128-129]. He testified that ratepayers should not be required to bankroll an advertising war between public utilities. [T. Vol 6, p. 129]. In the stipulation, however, the Company and the Public Staff agreed to include the actual level of advertising expenses incurred in the test period. [Exhibit JHM-2, p. 3, ¶ (o)]. Both the Company and the Public Staff reserved their right with respect to the treatment of "promotional" advertising in future cases.

Public Staff witness Hoard proposed to reduce the Company's pro forma rate case expense to remove the unamortized balance of rate case expense from the Company's last general rate case. [T. Vol. 6, pp. 130-131]. In his rebuttal testimony, Company witness Guy objected to the Public Staff's proposal. [T. Vol. 3, p. 152]. In the stipulation, however, the Company agreed to the Public Staff's adjustment. [Exhibit JHM-2, p. 3, ¶ (p)].

Public Staff witness Hoard proposed to adjust insurance expense to allocate a portion of the expense to construction and non-utility operations and to reflect the current premium levels for the property and directors' and officers' liability insurance policies. [T. Vol. 6, pp. 131-132]. In the stipulation, the Company agreed to the Public Staff's adjustment. [Exhibit JHM-2, p. 3, ¶ (p)].

Public Staff witness Hoard proposed to increase operation and maintenance expense by $130,926 to reflect increases in postage rates that became effective in February 1991. [T. Vol. 6, p. 132]. In the stipulation, the Company agreed with the Public Staff's proposal. [Exhibit JHM-2, p. 3, ¶ (p)].

Public Staff witness Hoard proposed to remove $25,865 of fees and reimbursed expenses paid by the Company which he contended were for legislative lobbying services during the test year. [T. Vol. 6, p. 132]. Company witness Guy testified that $24,000 of this amount was paid for consulting services in public relations and public affairs for the Company. [T. Vol. 3, p. 153]. On cross-examination, Mr. Guy testified that somewhere between 20% and 25% of the fees may be for legislative activities. [T. Vol. 4, p. 15]. In the stipulation, the Company and the Public Staff agreed to the inclusion of the entire $25,865. [T. Vol. 4, p. 12].

Public Staff witness Hoard proposed to amortize the $189,639 balance in Account 253-12 - Boiler Fuel Pricing (NC) as a reduction to operation and maintenance expenses over a three-year period. [T. Vol. 6, p. 132]. Company witness Guy testified that the Company was willing to refund the amount in the account to its customers but objected to the method proposed by the Public Staff because it is administratively burdensome and raises the possibility that the actual amount refunded to customers could be more or less than the amount in the account. [T. Vol. 3, p. 153]. The Public Staff accepted the Company's position in the stipulation. [Exhibit JHM-2, p. 3, ¶ (p)].

Company witness Guy testified that the current pension expense is $3,433,948. [T. Vol. 3, p. 140]. No party contested the inclusion of this expense in operation and maintenance expense.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 84-87

The Company offered evidence that actual depreciation expense during the test period was $8,166,336. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 6]. The Company proposed pro forma and accounting adjustments of $1,694,920. [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 6]. The Company contended that these adjustments are necessary to increase depreciation expense to the going level basis. [Exhibit BLG-1, Schedule 5, p. 5].

Public Staff witness Hoard proposed to reduce the Company's pro forma depreciation expense by (1) $211,766 to reflect adjustments proposed by the

Public Staff to end of test period plant and by (2) $165,199 to reflect the Public Staff's adjustments with respect to plant added after the end of the test period. (Hoard Exhibit I, Schedule 3, p. 1, Cols. (e) & (f), l. 6].

In the stipulation, the Company and the Public Staff agreed that the proper level of depreciation expense is $9,494,733. [Exhibit JHM-2, Schedule 1]. No other party offered any evidence as to the appropriate level of depreciation expense.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 88-101

The Company offered evidence that the actual level of general taxes during the test period was $11,375,833. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 7]. The Company proposed pro forma and accounting adjustments of $3,277,483. [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 7]. The Company contended that this adjustment is necessary to (1) increase property taxes to the going level basis, (2) increase payroll taxes to the going level basis and (3) increase gross receipts taxes following the adjustment to revenues. [Exhibit BLG-1, Schedule 7, p. 5].

Public Staff witness Hoard proposed to increase the Company's pro forma general taxes by $330,307 to reflect adjustments proposed by the Public Staff to revenues and to decrease the Company's pro forma general taxes by $122,768 to reflect the Public Staff's adjustments with respect to payroll and related items. [Hoard Exhibit I, Schedule 3, p. 1, Cols. (d), l. 7; Hoard Exhibit I, Schedule 3, p. 2, Col. (h), l. 7].

In the stipulation, the Company and the Public Staff agreed that the proper level of general taxes is $14,879,648. [Exhibit JHM-2, Schedule 1]. No other party offered any evidence as to the appropriate level of general taxes.

The Company offered evidence that the actual level of state income taxes during the test period was $1,217,176. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 8]. The Company proposed pro forma and accounting adjustments of ($287,166). [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 8]. The Company contended that this adjustment is necessary to reflect a computation of state income taxes after the other pro forma and accounting adjustments. [Exhibit BLG-1, Schedule 7, p. 5].

Public Staff witness Hoard proposed to increase the Company's pro forma state income taxes by $656,767 to reflect the Public Staff's adjustments to cost of gas, changes in fixed charges, volumes of gas sold, end of test year plant, incomplete plant, revenue based expenses, payroll and related adjustments, promotional advertising, miscellaneous operation and maintenance expense adjustments and interest synchronization. [Hoard Exhibit I, Schedule 3, pp. 1-2, Cols. (b)-(k), l. 8].

In the stipulation, the Company and the Public Staff agreed that the proper level of state income taxes is $1,401,835. [Exhibit JHM-2, Schedule 1]. No other party offered any evidence as to the appropriate level of state income taxes.

The Company offered evidence that the actual level of Federal income taxes during the test period was $5,414,444. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 9]. The Company proposed pro forma and accounting adjustments of ($1,309,711). [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 9]. The Company contended that this adjustment is necessary to reflect a computation of Federal income taxes after the other pro forma and accounting adjustments. [Exhibit BLG-1, Schedule 7, p. 5].

Public Staff witness Hoard proposed to increase the Company's pro forma Federal income taxes by $2,966,702 to reflect the Public Staff's adjustments to cost of gas, changes in fixed charges, volumes of gas sold, end of test year plant, incomplete plant, revenue based expenses, payroll and related adjustments, promotional advertising, miscellaneous operation and maintenance expense adjustments and interest synchronization. [Hoard Exhibit I, Schedule 3, pp. 1-2, Cols. (b)-(k), l. 9].

The Public Staff used a gross receipts tax rate of 3.22%, a state income tax rate of 7% and a Federal income tax rate of 34%. [Hoard Exhibit I, Schedule 3-6]. Gross receipts taxes are determined by applying the applicable rate to revenues net of uncollectibles. State income taxes are determined by applying the applicable rate to revenues net of expenses. Federal income taxes are determined by applying the applicable rate to revenues net of expenses and state income taxes.

In the stipulation, the Company and the Public Staff agreed that the proper level of Federal income taxes is $6,236,035. [Exhibit JHM-2, Schedule 1]. No other party offered any evidence as to the appropriate level of Federal income taxes.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 102-105

The Company offered evidence that the actual level of "amortization of investment tax credits" during the test period was $310,621. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 10]. The Company did not propose any pro forma adjustments. [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 10]. The Public Staff agreed both in its prefiled testimony and exhibits and in the stipulation that the appropriate pro forma level of "amortization of investment tax credits" is $310,621. [Hoard Exhibit I, Schedule 3, p. 1-2, l. 10]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 106-109

The Company offered evidence that the actual level of interest on customer deposits during the test period was $200,181. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 13]. The Company did not propose any pro forma adjustments. [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 13]. The Public Staff agreed both in its prefiled testimony and exhibits and in the stipulation that the appropriate pro forma level of interest on customer deposits is $200,181. [Hoard Exhibit I, Schedule 3, p. 1-2, l. 13]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 110-113

The Company offered evidence that it did not have any amortization of bond defeasance gain during the test period. [Exhibit BLG-1, Schedule 7, p. 1, Col. 1, l. 14]. The Company proposed to include $64,560 of amortization of bond defeasance gain as a pro forma adjustment. [Exhibit BLG-1, Schedule 7, p. 1, Col. 2, l. 14; Exhibit BLG-1, Schedule 7, p. 5]. The Public Staff agreed both in its prefiled testimony and exhibits and in the stipulation that the appropriate pro forma level of amortization of bond defeasance gain is $64,560. [Hoard Exhibit I, Schedule 3, p. 1-2, l. 14]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 114-125

Total pro forma operating revenue deductions under present rates is the sum of various pro forma expenses discussed above. The evidence on these components of total operation expenses is set forth above. In addition, in the stipulation, the Company and the Public Staff agreed that the appropriate pro forma level of "total operating revenue deductions" under present rates is $288,231,406. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 126-130

Net operating income for return is the result of subtracting total operating revenue deductions from total operating revenue. The evidence on both of these components of net operating income for return is set forth above. In addition, in the stipulation, the Company and the Public Staff agreed that the appropriate pro forma level of net operating income for return is $25,652,067. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 131-135

The Company offered evidence that plant in service at October 31, 1990, was $369,492,903. [Exhibit BLG-1, Schedule 7, p. 1]. In its initial filing, the Company proposed to increase plant in service by $33,658,242 to reflect estimated plant additions through June 30, 1991. [Exhibit BLG-1, Schedule 7, p. 5].

Public Staff witness Hoard proposed to adjust plant in service at the end of the test period to (1) remove $13,919,051 of construction work in progress which he contended was incorrectly included as both plant in service at the end of the test year and post-test year plant additions and (2) correct mathematical errors totalling $3,019,752. [T. Vol. 6, p. 115; Hoard Exhibit I, Schedule 2-3(a)]. Witness Hoard offered evidence to show that after the appropriate allocation of jointly used plant, the effect of these two adjustments is to reduce plant in service by $10,899,299. [Hoard Exhibit I, Schedule 2-2, page 2, Col. (d), l. 58]. At the hearing, the Company agreed with both of these adjustments. [T. Vol. 4, p. 22-23].

Public Staff witness Hoard also proposed in his prefiled testimony to increase plant in service for post-test year plant additions of $25,865,087 to recognize the effect of actual additions through February 28, 1991, and estimated additions for March 1991. [T. Vol 6, p. 116-117; Hoard Exhibit I, Schedule 2-3(a)]. This adjustment had the effect of reducing plant in service by $7,793,155. [Exhibit I, Schedule 2-3, l. 12].

In the stipulation, the Company and the Public Staff agreed to pro forma plant in service of $384,904,210. [Exhibit JHM-2, Schedule II]. Company witness Guy testified that the Public Staff included some post-March 31, 1991, plant additions, but that the number agreed to is virtually the same number as the Company's number which included no post-March 31, 1991, plant. [T. Vol. 4, pp. 16-19, 23].

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 136-139

The Company introduced evidence that leasehold improvements, net at the end of the test period were $9,188. [Exhibit BLG-1, Schedule 7, p. 1, l. 17]. The Company did not propose any pro forma or accounting adjustments. The Public Staff did not propose any adjustments to leasehold improvements, net. [Hoard Exhibit 1, Schedule 2]. No party other than the Company and the Public Staff offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 140-145

The Company offered evidence that accumulated depreciation at the end of the test period was $88,146,701. [Exhibit BLG-1, Schedule 7, p. 1, l. 18]. The Company proposed to increase this amount by $1,694,920 to reflect the adjustment to depreciation expense relating to plant additions. [Exhibit BLG-1, Schedule 7, p. 5]. Through the prefiled testimony and exhibits of witness Hoard, the Public Staff proposed to reduce pro forma accumulated depreciation by $211,766 to reflect the Public Staff's adjustments to plant in service at the end of the test year and by $165,199 to reflect the Public Staff's adjustments to plant additions after the end of the test year. [T. Vol. 6, pp. 116-117; Hoard Exhibit I, Schedule 2]. The Public Staff's adjustments would reduce accumulated depreciation to $89,464,656. In the stipulation, the Company and the Public Staff agreed that the appropriate pro forma accumulated depreciation, based on the agreed upon plant in service, is $89,475,098. [Exhibit JHM-2, Schedule II]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 146-149

The Company introduced evidence that customer advances for construction at the end of the test period were $694,240. [Exhibit BLG-1, Schedule 7, p. 1, l. 19]. The Company did not propose any pro forma or accounting adjustments. The Public Staff did not propose any adjustments to customer advances for construction. [Hoard Exhibit 1, Schedule 2]. No party other than the Company and the Public Staff offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 150-156

Net plant in service is the sum of gas utility plant in service, net leasehold improvements, less accumulated depreciation and customer advances for construction. The evidence on all of these components of net plant in service is set forth above. Additionally, in the stipulation, the Company and the Public Staff agreed that the appropriate pro forma level of net plant in service is $294,744,060. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 157-160

The Company offered evidence that the allowance for working capital should be $21,871,520. [Exhibit BLG-1, Schedule 7, p. 1, l. 21]. The Public Staff proposed several adjustments to cash working capital. [T. Vol. 6, pp. 117-120; Hoard Exhibit 1, Schedule 2, l. 6]. These adjustments would reduce cash working capital to $12,520,445. [Hoard Exhibit 1, Schedule 2, l. 6]. In the stipulation, the Company and the Public Staff agreed to cash working capital of $12,735,494. [Exhibit JHM-2, Schedule II]. No other party offered any evidence on cash working capital.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 161-164

The Company offered evidence that the appropriate level of accumulated deferred taxes is $30,639,920. [Exhibit BLG-1, Schedule 7, p. 1, l. 22]. Public Staff witness Hoard proposed to adjust accumulated deferred taxes by $1,132,091 to reflect various adjustments for depreciation, cost of gas, revenues and refund of South Carolina bill credits. [Hoard Exhibit I, Schedule 2-4]. After the Public Staff's adjustments, the accumulated deferred taxes are $31,772,011. [Hoard Exhibit I, Schedule 2, Col. (i), l. 7]. In the stipulation, the Company agreed to the Public Staff's adjustment. [Exhibit JHM-2, p. 2, ¶ (e)]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 165-168

The Company offered evidence that the appropriate amount of cost-free capital to include in rate base is $90,041. [Exhibit BLG-1, Schedule 7, p. 1. l. 23]. Public Staff witness Hoard proposed to adjust cost-free capital (1) to remove from rate base the unrecovered regulatory fee adjustment proposed by the Company and (2) to recognize cost-free capital resulting from the excess of pension expense over pension plan contributions. [T. Vol. 6, pp. 124-125; Hoard Exhibit 1, Schedule 2; Hoard Exhibit I, Schedule 2-5]. After these adjustments, cost-free capital would be $1,131,233. [Hoard Exhibit I, Schedule 2, Col. (i), l. 8]. In the stipulation, the Company and the Public Staff agreed to cost-free capital of $1,205,326 to reflect the other adjustments agreed to by them. [Exhibit JHM-2, p. 2, ¶ (g).

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 169-172

The Company offered evidence that the appropriate going level of unamortized gain on bond defeasance is $59,188. [Exhibit BLG-1, Schedule 7, p. 1, l. 24]. The Public Staff accepted this number in the stipulation. [Exhibit JHM-2, p. 2, ¶ (h)]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 173-178

The rate base is the sum of net plant in service, allowance for working capital, less accumulated deferred taxes, cost-free capital and unamortized gain on bond defeasance. Evidence with respect to each of these components has been set forth above.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 179-183

Return on rate base is determined by dividing net operating income for return by rate base. As set forth above, net operating income for return is $25,652,067 and rate base is $274,443,029.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 184-188

The Company proposed a capital structure consisting of 46.63% long-term debt and 53.37% common equity. [Exhibit BLG-1, Schedule 7, p. 2]. The Public Staff proposed a capital structure consisting of 45.47% long-term debt, 5.18% short-term debt and 49.35% common equity. [T. Vol. 6, p. 95]. Both the Company and the Public Staff included proposed offerings of common stock and long-term debt. [T. Vol. 4, pp. 7-8; T. Vol. 6, p. 17]. In the stipulation, the Company and the Public Staff agreed to a capital structure consisting of 46% long-term debt, 2% short-term debt and 52% common equity. No other party offered any evidence on the appropriate capital structure.

In support of its recommended capital structure, the Company offered evidence that its per book capitalization at the end of the test period consisted of long-term debt of $184,923,080 and common equity of $196,176,748. [Exhibit BLG-1, Schedule 7, p. 2]. It also offered evidence that it proposed to issue 1,250,000 shares of common stock and $55 million of long-term debt in 1991. [T. Vol. 4, pp. 42-43; Exhibit BLG-1, Schedule 7, p. 2]. Company witness Murry also testified that the Moody's companies' equity ratios have averaged consistently in the 51% to 53% range. [T. Vol. 4, p. 9]. He also testified that Piedmont's actual common equity ratio has fluctuated from a low of 49% in 1986 to a high of 54.8% in 1987 and that Piedmont's year end 1990 common stock equity is estimated to be 51.3%. [T. Vol. 4, p. 44].

In support of its recommended capital structure, the Public Staff offered testimony showing (1) that in the Company's last general rate case, Docket No. G-9, Sub 278, the Commission adopted a capital structure consisting of 44.11% long-term debt, 6.08% short-term debt and 49.81% common equity and (2) that the Company's 12-months average capital structure at February 28, 1991, was 44.88% long-term debt, 6.41% short-term debt and 48.71% common equity [T. Vol. 6, p. 92]. The Public Staff also offered testimony that the Company has historically employed significant amounts of short-term debt and that the Company should continue to employ short-term debt. [T. Vol. 6, pp. 89-90].

In rebuttal to the Public Staff's recommendation to include short-term debt in capital structure, Company witness Murry testified that the practice of including short-term debt in a utility's capital structure is weak conceptually and, in practice, is somewhat unusual or special.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 189-192

Both the Company and the Public Staff offered evidence that the cost of long-term debt is 9.9%. [Exhibit BLG-1, Schedule 7, p. 2; T. Vol. 6, p. 95]. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 193-196

The Company did not include short-term debt in its capital structure; therefore, it did not offer any evidence on the cost of short-term debt in its initial filing. The Public Staff proposed a cost of short-term debt of 6.73%. [T. Vol. 6, p. 95]. In rebuttal testimony, Company witness Murry testified that the 6.73% rate is inconsistent with the rates in the short-term market, *e.g.*, the overnight rates for banks with the Federal Reserve and the 90-day Treasury bill market and that it does not represent the opportunity costs of investing in a company with a long-term obligation to serve. [T. Vol. 4, p. 63]. In the stipulation, the Company and the Public Staff agreed to a short-term debt cost of 8.5%. No other party offered any evidence on the cost of short-term debt.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 197-200

The return on common equity under existing rates is mathematically determined by dividing the net operating income left over after the payment of interest on long-term and short-term debt by the common equity portion of the rate base. The various components of this mathematical determination were agreed to by the Company and the Public Staff in the stipulation. The evidence supporting these components is set forth above.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 201-224

The Company requested a return on common equity of 14.5%. [T. Vol. 4, p. 55]. In support of this request, Company witness Murry testified that he used the standard discounted cash flow (DCF) technique for estimating a fair return on common equity for Piedmont. [T. Vol. 4, p. 44]. Using earnings and per share growth estimates from 1989, he determined that the cost of equity capital estimates for Piedmont are 14.68% to 16.20%. [T. Vol. 4, p. 49; Exhibit DAM-1, Schedule 6]. Using the dividend growth estimates for 1989, he determined that the cost of equity capital is in the range of 11.75% to 13.27%. [T. Vol. 4, p. 49; Exhibit DAM-1, Schedule 7]. Using the earnings and per share growth estimates for 1990, he determined that the cost of equity capital for Piedmont ranges from 15.18% to 15.89%. [T. Vol. 4, p. 50; Exhibit DAM-1, Schedule 8]. Using the dividend growth estimates for 1990, he determined that the cost of equity capital is in the range of 12.25% to 12.95%. [T. Vol. 4, p. 50; Exhibit DAM-1, Schedule 9]. Using the current prices as reported in the *Wall Street Journal*, he determined that Piedmont's cost of capital estimate using the earnings per share growth rate to be 15.42% to 15.47%. [T. Vol. 4, p. 50; Exhibit DAM-1, Schedule 10]. Using the current prices as reported in the *Wall Street Journal*, he determined Piedmont's cost of capital estimate using the dividend growth rate to be 12.48% to 12.54%. [T. Vol. 4, p. 50; Exhibit DAM-1, Schedule 11].

Company witness Murry testified that to determine the cost of capital for Piedmont he relied primarily on his DCF analysis of Piedmont, especially the current estimates. [T. Vol. 4, p. 51]. He also based his analysis on a review of the comparable earnings of other utilities, the Company's financial health and relative risk and general economic conditions. [T. Vol. 4, pp. 51-52]. He testified that DCF calculations produce the basic, marginal cost of common equity for the Company; therefore, he testified that the allowed return should include a cushion to ensure that the recommended return using the DCF method is actually achievable by the Company. [T. Vol. 4, p. 52]. Based on his DCF calculations and the various influences and considerations on the Company's stock, he recommended a return on common equity in the range of 14% to 14.5%, to which should be added 50 basis points above the mid-point of the DCF range to provide an adequate cushion for the Company to earn its allowed return in normal circumstances. [T. Vol. 4, p. 53]. Finally, he testified that his return recommendation would provide the Company with an interest coverage after taxes which is comparable to the coverage after taxes of the comparable Moody's companies. [T. Vol. 4, p. 55].

Public Staff witness Sessoms also relied on the DCF model to determine the cost of common equity to the Company. [T. Vol. 6, p. 100]. He employed three methods to estimate the expected growth in dividends. The first method was a log-linear least squares regression. [T. Vol. 6, pp. 100-101]. The second method was to employ the *Value Line* projections of growth in earnings per share, dividends per share and book value per share. [T. Vol. 6, p. 101]. The third method was to use the *Value Line* presentation of the compound annual growth rate in earnings per share, dividends per share and book value per share. [T. Vol. 6, p. 101]. Based on the results of his DCF study, witness Sessoms concluded that the investor return requirement for the Company is within the range of 12.3% to 12.6% and that the investor return requirement for the comparable companies is within the range of 11.8% to 12.4%. [T. Vol. 6, p. 102]. From these ranges, he recommended an investor return requirement for the Company's common stock of 12.4%. [T. Vol. 6, p. 25]. Based on an examination of the Company's known and actual financing costs over the last ten years, witness Sessoms calculated a factor of .12% which he testified would allow the Company to recover its known financing costs when added to the investor return requirement. [T. Vol. 4, p. 103]. The addition of this .12% financing cost to the 12.4% investor return expectation produced witness Sessoms' final recommendation of 12.52%.

In the stipulation, the Company and the Public Staff agreed to a return on common equity of 12.9%. No other party offered any evidence on this issue.

Company witness Maxheim testified that the Company has been adding customers, making capital investments in its utility properties and obtaining new long-term capital investments in its utility properties at unprecedented levels. He testified that for the year ending October 31, 1991, Piedmont expects to add 23,900 customers, to invest $69.4 million in its utility operations and to sell in excess of $100 million of long-term securities.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 225-228

The following schedules summarize the gross revenues and rate of return the Comany should have a reasonable opportunity to achieve based upon the increase approved herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions heretofore and hereinafter found reasonable by the Commission. The items making up the various components of those schedules under "Present Rates" is supported by the evidence, findings and conclusions set forth above. The amounts set forth in the "Increase Approved" and "After Increase Approved" columns of Schedules I and II and in columns under "Approved Rates" in Schedule III are matters of mathematical computation which have been agreed to by the Company and the Public Staff in the stipulation. The amounts set forth in the columns "Benchmark Cost of Gas Change" and "After Change In Benchmark Cost of Gas" in Schedule I reflect the change from a $3.4524 benchmark cost of gas to a $2.50 benchmark cost of gas and are also matters of mathematical computation which have been agreed to by the Company and the Public Staff in the stipulation.

SCHEDULE I
PIEDMONT NATURAL GAS COMPANY, INC
DOCKET NO. G-9, SUB 309
STATEMENT OF NET OPERATING INCOME FOR RETURN
For the Test Year Ended October 31, 1990

Item	Present Rates	Increase Approved	After Increase Approved	Benchmark Cost of Gas Change	After Change In Benchmark Cost of Gas
Operating Revenues:					
Sale and transportation of gas	$313,347,849	$9,213,864	$322,561,713	$(50,690,499)	$271,871,214
Other operating revenue	535,624	450,569	986,193		986,193
Total operating revenue	313,883,473	9,664,433	323,547,906	(50,690,499)	272,857,407
Operating Revenue Deductions:					
Cost of gas	211,707,096		211,707,096	(49,058,265)	162,648,831
Operation and maintenance	44,687,059	31,177	44,718,236		44,718,236
Depreciation	9,494,733		9,494,733		9,494,733
General taxes	14,879,648	310,567	15,190,215	(1,632,234)	13,557,981
State income taxes	1,401,835	652,591	2,054,426		2,054,426
Federal income taxes	6,236,035	2,947,836	9,183,871		9,183,871
Amortization of ITC	(310,621)		(310,621)		(310,621)
Interest on customer deposits	200,181		200,181		200,181
Amortization of bond defeasance gain	(64,560)		(64,560)		(64,560)
Total operating revenue deductions	288,231,406	3,942,171	292,173,577	(50,690,499)	241,483,078
Net operating income for return	$ 25,652,067	$5,722,262	$ 31,374,329		$ 31,374,329

SCHEDULE II
PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 309
STATEMENT OF RATE BASE AND RATE OF RETURN
For the Test Year Ended October 31, 1990

	Present Rates	After Approved Rates
Utility plant in service	$384,904,210	$384,904,210
Leasehold improvements, net	9,188	9,188
Accumulated depreciation	(89,475,098)	(89,475,098)
Customer advances for construction	(694,240)	(694,240)
Net plant in service	294,744,060	294,744,060
Allowance for working capital	12,735,494	12,735,494
Accumulated deferred taxes	(31,772,011)	(31,772,011)
Cost-free capital	(1,205,326)	(1,205,326)
Unamortized gain on bond defeasance	(59,188)	(59,188)
Original cost rate base	$274,443,029	$274,443,029
Rate of return	9.35%	11.43%

SCHEDULE III
PIEDMONT NATURAL GAS COMPANY, INC.
DOCKET NO. G-9, SUB 309
STATEMENT OF CAPITALIZATION AND RELATED COSTS
For the Test Year Ended October 31, 1990

Type of Capital	Rate Base	Ratio	Embedded Cost/Return %	Net Operating Income
		Present Rates		
Long-term debt	$126,243,793	46.00%	9.90%	$12,498,136
Short-term debt	5,488,861	2.00	8.50	466,553
Common equity	142,710,375	52.00	8.89	12,687,378
Total	$274,443,029	100.00%		$25,652,067
		Approved Rates		
Long-term debt	$126,243,793	46.00%	9.90%	$12,498,136
Short-term debt	5,488,861	2.00	8.50	466,553
Common equity	142,710,375	52.00	12.90	18,409,640
Total	$274,443,029	100.00%		$31,374,329

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 229-233

Company witness Schiefer testified that the heating-only classification was established in an attempt to charge the low load factor heating-only consumer the cost of providing the more expensive winter peaking gas services and supplies. He testified that this objective has not been accomplished through the Rate 102 heating-only schedule because many commercial heating-only customers found they could qualify for the year-around schedule by adding a small gas appliance such as a gas light or small water heater which uses an insignificant amount of gas when compared to the large winter heating load. Witness Schiefer testified that he believes the better way to recognize the cost associated with a heating-only customer is through use of the summer-winter differential. [T. Vol. 5, p. 115]. No party offered any opposition to this proposal.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 234-236

Company witness Schiefer testified that the Company has only ten customers on Rate Schedule 102 Air Conditioning and that these customers can best be served under the proposed Rate Schedule 102. [T. Vol. 5, p. 116]. No party opposed this recommendation.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 237-242

In his prefiled testimony, Company witness Schiefer proposed that Rate Schedule 102 (Small General Service) and Rate Schedule 103 (Large General Service) incorporate identical volume step rates. He explained that Rate Schedule 102 customers pay higher rates because they use less than 50 dts. per day. The 50 dts. per day was established during curtailment days and has no significant relationship to the cost of serving customers. Witness Schiefer stated that differences in rates for size distinctions are best handled through step rates which allow for a gradual price differential based on size. [T. Vol. 5, p. 116]. He further testified that Piedmont has had a lot of controversy with customers contending that they have been placed on the wrong rate schedule. If the rates are the same for Rate 102 and Rate 103, no customer will be disadvantaged by being placed on the wrong rate schedule. [T. Vol. 5, p. 123].

In his prefiled testimony, Public Staff witness Curtis recommended establishing different rates for Rate Schedule 102 and Rate Schedule 103. Witness Curtis testified that his recommendation gives "recognition to the fact that 102 customers are small customers using less than 50 dt/day whereas 103 customers are larger customers using over 50 dt/day" and "Rate Schedule 103 customers have been subject to more interruption and therefore should pay a lower rate for the same quantity of gas." [T. Vol. 6, pp. 159-160].

In his rebuttal testimony, witness Schiefer testified that he is aware of no ratemaking principle that provides that a smaller customer should pay a different rate simply because he is smaller and that Piedmont has not involuntarily curtailed a Rate 103 customer since 1976. [T. Vol. 6, p. 123].

In the stipulation, the Company and the Public Staff agreed to identical rates for Rates 102 and 103. No other party offered any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 243-260

Company witness Fleenor, Public Staff witness Curtis and CUCA witness Schoenbeck all presented cost of service studies. These studies show various rates of return for the different customer classes.

Company witness Fleenor prepared a cost of service study in accordance with the NARUC manual for gas rate design. He also prepared a cost of service study following the same principles for the rates designed in the stipulation. [T. Vol. 5, p. 62]. On cross examination, he agreed that cost of service studies are much more an art than they are an exact science. [T. Vol. 5, p. 81, lines 1-2].

Public Staff witness Curtis prepared a cost of service study based on a 50% annual sales and 50% three-day peak methodology. [T. Vol. 6, p. 157]. Witness Curtis testified that because cost studies are judgmental, no one study should be relied upon. He stated that his cost of service study is only a guideline and cannot precisely determine the returns paid by each customer class. [T. Vol. 6, p. 158].

CUCA witness Schoenbeck also presented a cost of service study. [Schoenbeck Exhibit B, Schedules 4 & 5]. In this study, witness Schoenbeck reclassified and reallocated certain gas related costs. [T. Vol. 6, p. 53].

Company witness Schiefer testified that he considered traditional rate design principles, the results of the cost of service study prepared by witness Fleenor and the need to remain competitive when he designed Piedmont's proposed rates. [T. Vol. 5, p. 112]. He testified that he considered the following economic factors in designing the proposed rates: (1) value of service, (2) the need to avoid discrimination among classes of service and (3) system load equalization and revenue stability. [T. Vol. 5, p. 112]. He testified that the value of service considerations rest on the premise that the value of a utility service to a consumer cannot be greater than the cost to that consumer of an equally satisfactory alternate service. [T. Vol. 5, p. 112]. He testified that in order to avoid undue discrimination when justifying lower rates to a particular class of customers (such as industrial customers), he considered whether the service is firm or interruptible, the quantity of use, the cost of service and the value of service. [T. Vol. 5, p. 113]. He testified that certain protective measures need to be included in gas rates to avoid disastrous consequences in the event of extremely warm weather or a major business decline. [T. Vol. 5, pp. 113-114]. He testified that, while he does not believe that a cost of service study should be the only factor used to design rates, it must be considered especially when a class of customers has a negative return. [T. Vol. 5, p. 114]. He testified that because of the need to remain competitive, he proposed only a minor increase in the summer rates of Rates 104 and 114. [T. Vol. 5, p. 114]. On cross-examination, he testified that historical rate levels should be considered and that in the last two general rate cases the entire increase went to Rate Schedules 101 and 102; whereas, industrial rates were reduced. [T. Vol. 6, p. 10]. He also testified that interruptible alternate fuel customers pose a financial risk to the Company because of their ability to switch to alternate fuels. [T. Vol. 6, p. 10-11].

In agreeing to the stipulated rates, witness Schiefer testified that he considered the desire to achieve a positive return on residential customers, the desire to combine Rate Schedules 102 and 103, the desire to recover more costs from winter customers and the desire to keep summer rates for Rate Schedules 103 and 104 at least flat. [T. Vol. 5, pp. 159-160]. He testified that the stipulated rates "pretty much" meet his objectives. [T. Vol. 5, p. 161].

Public Staff witness Curtis testified that the Commission should not design rates to provide for equalized class returns because (1) the Commission would be required to rely on a single subjective cost of service study, (2) the cost of serving various classes of customers cannot be fairly determined in a cost study, (3) alternate fuel customers pose a greater financial risk to the Company, (4) alternate fuel customers should be charged on "value of service" as well as cost of service and (5) high priority customers already pay a much higher rate per unit of gas. [T. Vol. 6, pp. 161-162].

CUCA witness Schoenbeck urged the Commission to move over time to cost-based rates for all customer classes. [T. Vol. 6, p. 71]. He testified that the class increases resulting from the stipulation are inconsistent with the cost-of-service evidence presented in this proceeding by both the Company and the Public Staff. [T. Vol. 6, p. 71]. He found "particularly offensive" the increase in the "combined Schedule 103/113 class." [T. Vol. 6, p. 71]. He recommended a 10% increase to residential customers and a 2% decrease to other customer classes. [T. Vol. 6, p. 73].

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 261-267

Stipulated rates under Rate Schedules 113 and 114 are "full margin rates"; that is, the rate charged for transporting gas under Rate Schedule 113 is the full margin (rate less cost of gas) charged for sales gas under Rate Schedule 103 and the rate charged for transporting gas under Rate Schedule 114 is the full margin charged for sales gas under Rate Schedule 104. CUCA witness Schoenbeck objected to the use of full margin rates. [T. Vol. 6, pp. 39-41]. He contended that full margin rates are based on the incorrect assumption that transportation service is similar to sales service. [T. Vol. 6, p. 40]. He further contended that this assumption is incorrect because the utility is obligated to acquire an adequate supply of gas for its sales customers but is not required to provide gas for its transportation customers. [T. Vol. 6, p. 40].

Mr. Schiefer testified that CUCA has opposed full margin rates many times before. For example, CUCA made this recommendation in Docket No. G-9, Sub 250, in Docket No. G-9, Sub 251, and in Docket No. G-9, Sub 278, and, in all three cases, the Commission ruled against CUCA. [T. Vol. 5, pp. 125-126].

In Docket No. G-9, Sub 250, the Commission said:

> "In our determination of whether existing Rate 107 is discriminatory and whether proposed Rate 107 is just and reasonable, the Commission must consider a number of factors. These factors include cost of service, value of service, quantity of gas used, the time of use, the manner of use, the equipment which the utility must provide and maintain in order to take care of the customers' requirements, competitive conditions and consumption characteristics.

Utilities Commission v. N.C. Textile Asso., 313 N.C. 215, 328 S.E.2d 264 (1985); *Utilities Commission v. Bird* Oil Co., 302 N.C. 14, 273 S.E. 2d 232 (1980); and *Utilities Commission v. Piedmont Natural Gas Company*, 254 N.C. 734, 120 S.E.2d 77 (1961)."

"The Commission has considered each of these factors and has concluded that no justification exists for a difference between the margins earned on the two rate schedules."

*

"No convincing evidence has been presented to justify the charging of lower rates for customers receiving gas under Rate 107 than for customers receiving gas under Rate 104. As stated by Public Staff witness Nery: 'If transportation rates escape responsibility for full margin, other captive customers will unfairly subsidize transportation customers and will pick up the additional cost.' Such a result would be unfair and unlawful."

In Docket No. G-9, Sub 251, the Commission said:

"Specifically, the Commission continues to find no justification for a difference between the margins earned on the Company's sales rate schedule and its transportation rate schedule. In making this determination, the Commission has considered a number of relevant factors, including cost of service, value of service, quantity of gas used, the time of use, the manner of use, the equipment which Piedmont must provide and maintain in order to take care of the requirements of its customers, competitive conditions and consumption characteristics. .

It is obvious to the Commission that the services performed by Piedmont are the same whether service is provided under the sales rate or transportation rate."

In Docket No. G-9, Sub 251, the Commission also found that regardless of whether the service is rendered under Rate 104 or 107, (1) the gas passes through the same pipes, meters and regulators, (2) Piedmont provides the same load balancing and use of storage, (3) the same employees perform the billing services, (4) there is no difference to customers in the value of the service received, (5) the use by the customers is the same and (6) their consumption characteristics are the same.

Witness Schiefer testified that there have been no changes in any of the six factors listed by the Commission since the Commission issued its order in Docket No. G-9, Sub 251.

With respect to witness Schoenbeck's contention that Piedmont's transportation rates improperly include acquisition costs, witness Schiefer testified that Piedmont has to acquire gas for its transportation customers because transportation customers buy gas for transportation only on a very short-term basis, and they rely on Piedmont to provide gas when that transportation gas supply is not available. [T. Vol. 5, p. 135]. He further testified that witness Schoenbeck made this same contention in Docket No. G-9, Sub 278, and that the Commission rejected this contention as follows:

"Witness Schoenbeck contended that Piedmont's transportation rates improperly include gas acquisition costs. Witness Schiefer disagreed. He testified that when Piedmont transports customer-owned gas, Piedmont must deal with the producer selling that gas, the pipeline transporting the gas and the various regulatory agencies who must approve the transaction; that these services are very similar to the services rendered in connection with sales services and are certainly not less costly; and that any attempt to isolate the costs of performing these services for transportation gas and for sales gas would be speculative at best."

Witness Schiefer testified that the conditions referred to in the Commission's order in Docket No. G-9, Sub 278, still exist today.

Witness Schiefer testified that Piedmont also has full margin rates in the other two states in which it operates. [T. Vol. 5, p. 134].

In the stipulation, the Public Staff supported full margin rates.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 268-272

Company witness Schiefer recommended that the reconnection fee for residential customers be increased from $15.00 to $35.00 for the period February through August and from $15.00 to $50.00 for the period September through January. For Rate 102 customers, he recommended that the reconnection fee be increased from $25.00 to $50.00 for the period February through August and from $25.00 to $75.00 for the period September through January. [T. Vol. 5, p. 118]. In support of this recommendation, he testified that the current charge for reconnecting a customer's service is not sufficient to cover the costs involved in providing this service. [T. Vol. 5, p. 119]. He also testified that only about 5% of Piedmont's North Carolina customers have reconnects and that he did not think it was fair for the other 95% to subsidize this 5%. [T. Vol. 6, p. 7]. He also testified that it costs more to reconnect customers during the September reconnection season. [T. Vol. 6, p. 6]. No other party offered any testimony on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 273-277

The evidence upon which these findings and conclusions are based is set forth above.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 278-280

Company witness Schiefer recommended miscellaneous changes in the tariff language. He testified that the changes in the tariff language clarify the intent of the tariffs. [T. Vol. 5, p. 119]. The changes are shown on marked-up copies of the rate schedules contained in Exhibit WFS-1. No party offered any evidence in opposition to the proposed changes.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 281-283

In his prefiled testimony and exhibits, Company witness Schiefer recommended changes to the language in Piedmont's service regulations. [T. Vol. 5, p. 111;

Exhibit WFS-2]. In his prefiled testimony, Public Staff witness Curtis opposed certain changes proposed by the Company and proposed certain additional changes. [T. Vol. 6, pp. 166-167; Curtis Exhibit K]. On rebuttal, witness Schiefer testified that he opposed several of the changes proposed by witness Curtis. [T. Vol. 5, pp. 123-125]. At the hearing, the Company and the Public Staff announced that they had worked out all of their differences as to the language of the service regulations and the agreed upon service regulations were introduced into evidence as Revised Exhibit WFS-2. The agreement between the Company and the Public Staff did not extend to the PGA provisions which are a part of the service regulations. No other party offered any evidence with respect to the service regulations.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 284-292

Company witness Boggs provided the following history of the procedures under which this Commission has permitted the Company to recover its costs of gas:

> Many years ago, the Commission adopted rules and regulations which permitted natural gas utilities to change their rates to reflect changes in their wholesale cost of gas. Under those PGA regulations, natural gas utilities were permitted to increase their rates when their wholesale cost of gas increased and were required to decrease their rates when their wholesale cost of gas decreased. At the time when these PGA regulations were adopted by the Commission, most of the gas sold in North Carolina was purchased under Transco's FERC-approved CD-2 Rate Schedule, and the PGA regulations and the rates set under those regulations were designed to reflect that fact. After the FERC issued Order No. 436, it became possible for Piedmont to purchase gas on the spot market at prices considerably less expensive than the prices available to Piedmont under Transco's CD-2 Rate Schedule. Since the PGA regulations in effect at that time did not make provision for Piedmont to pass-through these gas costs savings to its customers, Piedmont made a filing in Docket No. G-9, Sub 257, requesting the Commission to approve a mechanism under which Piedmont could pass-through these savings to its customers through a mechanism called the "Spot Savings Program."
>
> The purpose of the Spot Savings Program was to provide an equitable way of sharing any "savings" resulting from the purchase of gas on the spot market. "Savings" was defined as the difference between (a) Transco's CD-2 commodity cost of gas and (b) the average cost at Piedmont's city gate of all other system gas transported to Piedmont at its city gate. In general, the savings from the first 30,000 dts. per day were put into a deferred account for distribution to all customers. Any remaining savings were first used to offset negotiated losses under Rate Schedule 108 and the remainder was placed in a deferred account for distribution to all customers.
>
> The Spot Savings Program did not replace the Commission's PGA regulations. It was designed to work in tandem with the PGA regulations. Piedmont continued to file under the PGA regulations for changes in its wholesale cost of gas from Transco. Changes in the wholesale cost of gas purchased from Transco were passed on to Piedmont's customers through the

PGA regulations, and changes in the cost of spot gas were passed on to Piedmont's customers through the Spot Savings Program.

The Spot Gas Savings Program was used by Piedmont from October 1985 until February 1990. During that time, the program was modified, amended, clarified and/or extended by the Commission on several occasions.

Piedmont ceased to use the Spot Savings Program in February 1990 for several reasons. First, on April 3, 1989, Transco filed a Stipulation and Agreement with the FERC which, among other things, provided that settling customers would discontinue purchasing gas under Transco's CD-2 Rate Schedule effective April 1, 1989. Piedmont is a settling customer under the Stipulation and Agreement and, therefore, ceased purchasing gas under Transco's CD-2 Rate Schedule effective April 1, 1989. Since Piedmont was no longer purchasing gas under Transco's CD-2 Rate Schedule, the use of the CD-2 commodity cost of gas was no longer an appropriate benchmark for use in the Spot Gas Program.

Second, it had become obvious that the PGA regulations were no longer appropriate. The PGA regulations were set forth in the Commission's Rule R1-17(g). Several provisions of that rule are applicable only to changes in the wholesale cost of gas approved by the FERC.

Piedmont ceased to use the Spot Savings Program under the following circumstances. On April 20, 1989, Piedmont filed an application in Docket No. G-9, Sub 291, for an amendment to the Spot Savings Program. On May 3, 1989, the Commission set Piedmont's application for hearing but approved certain interim accounting procedures to account for changes in Piedmont's cost of gas pending the hearing. Prior to the hearing, Piedmont and the Public Staff filed stipulations with the Commission which, among other things, provided a mechanism for Piedmont to pass through changes in its wholesale cost of gas pending its next general rate case. These procedures were incorporated into a document called Piedmont's "North Carolina Purchased Gas Adjustment Clause" and were approved by the Commission in its order of February 13, 1990.

The Commission's February 13, 1990, Order in Docket No. G-9, Subs 289, 291 and 296, has been appealed to the courts by CUCA. In addition, CUCA has appealed two subsequent orders of the Commission which authorized Piedmont to adjust its rates under the new PGA Clause. These two orders are the Commission's order of October 31, 1990, in Docket No. G-9, Subs 300 and 306, and the Commission's order of November 21, 1990, in Docket No. G-9, Sub 308.

[T. Vol. 4, pp. 106-110].

Company witness Boggs testified that Piedmont is proposing to revise the PGA clause effective on the effective date of the rates proposed in this proceeding for several reasons. According to witness Boggs, the present PGA Clause was agreed to by Piedmont and the Public Staff with the express understanding that it was to provide a temporary solution pending Piedmont's next general rate case. As a result, the PGA Clause contains certain provisions relating to the recovery of specific demand charges resulting from Transco's Southern Expansion Project and Columbia's backhaul project which would not be appropriate in a more permanent PGA Clause. In addition, witness Boggs testified that the Company is proposing to amend the PGA Clause to provide for a 100% "true-up" of all of its gas costs. [T. Vol. 4, p. 111].

Witness Boggs offered several reasons in support of the Company's request for a 100% true-up of gas costs. She testified that, at least in theory, there are two ways a natural gas utility could recover its gas costs. One way would be to treat these costs like any other costs, estimate the amount of the costs in a general rate case and establish rates on that estimate. According to witness Boggs, actual gas costs will almost certainly differ enormously from any such estimate because of frequent changes in the wholesale costs of gas, and, therefore, this method would result in the utility either earning substantially more or substantially less than its allowed return and would result in the filing of repeated general rate cases. Witness Boggs testified that the other way of recovering gas costs is through a PGA mechanism. Witness Boggs contended that since the whole purpose of a PGA Clause is to prevent the over-recovery or under-recovery of prudently incurred gas costs, it would not make sense to design the PGA clause to permit the utility to recover some lesser or some greater amount. Furthermore, according to witness Boggs, if the PGA Clause includes certain gas costs and excludes other gas costs, the utility may have an incentive to purchase more expensive gas simply because it could recover that gas cost in its PGA Clause. Finally, witness Boggs testified that under the 100% true-up proposed by the Company, the Company can purchase gas from the best source available with assurance that it can recover the cost of that gas unless it had acted imprudently. [T. Vol. 4, pp. 111-112].

The Company filed a proposed revised PGA Clause, a copy of which is attached as Appendix A to the Service Regulations filed by Mr. Schiefer as Exhibit WFS-2. According to witness Boggs, the revised PGA Clause accounts for all fixed costs of gas, for all gas supplies and services and for all commodity costs of all gas supplies and services. It also provides for Piedmont to keep the Commission and the Public Staff informed regarding its cost of gas and the accounting for its cost of gas. Under the revised PGA Clause, Piedmont will file with the Commission and the Public Staff a monthly report showing (a) the difference in its actual cost of gas and the cost of gas included in customers' rates, (b) the amount of negotiated losses incurred, (c) the amount of supplier refunds and/or surcharges, (d) the amount of refunds to customers, (e) the amount of interest accrued on the deferred account and (f) other data related to the deferred account, including the end of the month balance. [T. Vol. 4, p. 112].

Witness Boggs testified that Piedmont has all inclusive 100% true-up provisions for its cost of gas in South Carolina and Tennessee. [T. Vol. 4, p. 113].

Public Staff witness Curtis testified that the Public Staff is not opposed to the PGA Clause so long as the modifications set forth in Curtis Exhibit J are made. [T. Vol. 6, p. 156]. He testified that the major change in the Public Staff's proposal is that the costs of added capacity and storage are excluded. [T. Vol. 6, p. 156]. He testified that the added capacity and storage are excluded for the reasons set forth in a motion that was filed in this docket on April 18, 1991. [T. Vol. 6, p. 171].

CUCA witness Schoenbeck testified that providing a 100% true-up of all gas costs removes any incentive for Piedmont to closely monitor and control its costs associated with the purchase of gas supplies and services. [T. Vol. 6, p. 62]. He testified that the recovery of changes to the fixed costs associated with gas supplies and services, *i.e.*, demand and storage charges, should be excluded entirely from the PGA Clause. [T. Vol. 6, p. 63]. He contended that demand and storage costs would unlikely fluctuate with any great degree of volatility or regularity. [T. Vol. 6, pp. 63-64]. Finally, he testified that if the Commission permits the recovery of these cost changes, it should require that they be recovered on a basis which uses the three-day peak demand allocation factor. [T. Vol. 6, p. 65].

The Commission takes judicial notice that on July 8, 1991, the General Assembly enacted Chapter 598 of the 1991 Sessions Laws. This legislation amends Chapter 62 of the General Statutes by adding G.S. 62-133.4. This new statute addresses the same problem addressed by the revised PGA Clause proposed by Piedmont. The statute authorizes the Commission to allow rate changes "occasioned by changes in the cost of natural gas supply and transportation . . ." It provides for an annual review to "compare the utility's prudently-incurred costs with costs recovered from all of the utility's customers that it served during the test period." If prudently-incurred costs are greater or less than recovered costs, the Commission shall require the utility to refund any overrecovery or permit the utility to recover any deficiency. G.S. 62-133.4(e) provides that the "costs" subject to the statute shall be "defined by Commission rule or order and may include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system."

The Commission will initiate proceedings in the near future in order to define "costs" for purposes of G.S. 62-133.4 and in order to provide for the implementation of this statute. Since implementation of this statute will address the same issues addressed by the revised PGA Clause proposed by Piedmont in this case, the Commission concludes that the issues should be addressed through the specific provisions of the new statute, rather than through the Commission's general authority to approve ratemaking formulas in the context of a general rate case. The Commission will approve the revised PGA Clause proposed by Piedmont in this case. This approval shall be provisional in the sense that the Commission recognizes that the revised PGA Clause may be superceded by the procedures adopted to implement G.S. 62-133.4. The costs subject to the provisional revised PGA Clause which relate to additional pipeline capacity and storage shall be subject to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G.S. 62-133.4. Any monies so collected which are associated with additional pipeline capacity and storage shall be placed in a deferred account pending further Order of the Commission. The Commission's provisional approval of this aspect of the revised PGA Clause is without prejudice to the Commission's determination of which costs shall be subject to the rate changes and true-up provided by G.S. 62-133.4. The Commission will reexamine the treatment of fixed costs related to additional pipeline capacity and storage, as well as all other aspects of costs, as G.S. 62-134 is implemented.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 293-295

Witness Fleenor recommended in prefiled testimony that the appropriate level of two-state "unaccounted-for" gas volumes to be utilized in this case is 1,437,230 dekatherms. This volume was calculated by taking the "unaccounted for" level established in the last rate case and adjusting it to reflect the additional growth in volume up to the present rate case.

Public Staff witness Curtis used a two-state unaccounted-for volume of 955,476 dekatherms, based on a higher sales level than that utilized by Piedmont, in his prefiled testimony. This volume level of unaccounted-for gas represents Piedmont's twelve-month total at July of 1990. In addition, witness Curtis stated that 955,476 dekatherms typifies Piedmont's three-year average of unaccounted-for volumes over the past three-year period.

In their stipulation, the Public Staff and Piedmont agreed to use 1,437,230 dekatherms as the two-state volume level for unaccounted-for gas in this case. This level was not challenged by other parties, and appears reasonable to the Commission in light of the overall settlement. The North Carolina volume allocation of 74.44% times the 1,437,230 dekatherms yields a North Carolina unaccounted-for volume of 1,069,874 dekatherms.

Piedmont's calculation of 86,952 dekatherms for two-state company use volumes was uncontradicted. The North Carolina share is 64,727 dekatherms based on the 74.44% volume allocation.

Although the difference between Piedmont and the Public Staff as to the pro forma level of unaccounted-for volumes was resolved in their stipulation, the Public Staff, because of the size of this difference, recommended an annual true-up of the unaccounted-for volumes based on the actual level in June of each year. CUCA and the Attorney General presented no evidence on the unaccounted-for issue in this rate case.

Piedmont agreed that an unaccounted-for volume true-up would be proper if its version of the PGA Clause was approved. However, witness Maxheim testified that Piedmont would not stipulate to an unaccounted-for true-up without their PGA Clause, because "We simply do not believe that it is appropriate to include some gas costs in a true-up while excluding other gas costs." [T. Vol. 3, p. 82].

Since the Commission has approved the revised PGA Clause on a provisional basis pending implementation of G.S. 62-133.4, the Commission concludes that the true-up approved herein should be provisional pending implementation of G.S. 62-133.4. The Commission will reexamine the propriety and the procedure for a true-up of unaccounted-for gas volumes as part of the implementation of G.S. 62-133.4.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 296-306

Company witness Morris testified in support of the "Weather Normalization Adjustment" (WNA) Clause. He testified that the objective of the WNA Clause is to protect both the Company and its customers from the adverse impact of departures from normal weather. He testified that the Company's earnings and return and customers bills can vary widely due to departures from normal weather. [T. Vol. 4, p. 76].

Witness Morris performed an analysis of the impact of weather on the Company's earnings during the test period. He determined that during the months of November 1989 through March 1990 actual degree days were 2,768 as compared to normal degree days of 3,179 for the same period. According to witness Morris, this variation in degree days occurred even though the extremely cold December tempered the effects of the abnormally warm January, February, and March. He testified that the weather pattern during the test period affected customers by substantially increasing December bills and lowering January-March bills. [T. Vol. 4, p. 77].

Witness Morris testified that under the proposed WNA Clause, each customer's bill will be adjusted for weather for the particular cycle being billed. As a result, under the WNA Clause, a customer will be billed on a normal weather basis, the same basis on which rates were originally set by the Commission. [T. Vol. 4, p. 78].

Witness Morris testified that the WNA Clause produces a weather adjustment factor, expressed in cents per therm for that customer classification. The factor will be determined for each rate schedule and billing cycle based solely on the actual degree days in the billing period, compared to the normal degree days for the period. This factor is applied to the billed consumption as either an increase or decrease. It will apply to bills rendered during the months of October through May. The formula for determining the factor is as follows:

$$WNA = \frac{R \times (HSF \times (NDD-ADD))}{BL + (HSF \times ADD)}$$

Where:

WNA = Weather Normalization Adjustment factor for any particular rate schedule expressed in cents per therm.

R = Base rate (approved rate less cost of gas) for any particular rate schedule.

HSF = Heat Sensitive Factor for any particular rate schedule utilized by the Commission in determining normalized test period revenues.

NDD = Normal billing cycle heating degree days utilized by the Commission in determining normalized test period revenues.

ADD = Actual billing cycle heating degree days.

BL = Base load sales for any particular rate schedule utilized by the Commission in determining normalized test period revenues.

[T. Vol. 4, p. 78-79].

Witness Morris testified that the effect of this mechanism is to raise bills when customers can best absorb the adjustment because warm weather has resulted in reduced consumption. On the other hand, the WNA Clause operates to lower bills during extremely cold periods when consumption is high. [T. Vol. 4, p. 79].

According to witness Morris, the WNA Clause produces a weather adjustment factor for each customer classification determined to be weather sensitive. As proposed by the Company, this factor would be applied to the following rate schedules: Rate Schedule 101 - Residential Service and Rate Schedule 102 - Small General Service. [T. Vol. 4, p. 80].

Witness Morris testified that several other gas companies have had weather normalization mechanisms approved in Georgia and in New York. [T. Vol. 4, p. 80].

Public Staff witness Curtis testified that the Public Staff does not oppose the concept of the WNA Clause providing certain changes are made. He proposed to change from an eight-month to a five-month implementation period, to include Rate Schedule 103 customers in the WNA Clause and to implement a band of 5% on either side of normal weather to which the WNA Clause would not apply. He testified that Piedmont's winter period in its rate schedules is the five months of November through March and that 87% of the degree days occur during this five-month period. He also testified that Rate Schedule 103 customers are weather sensitive. [T. Vol. 6, pp. 163-165].

In the stipulation, the Company and the Public Staff agreed that the WNA Clause as filed by the Company should be approved by the Commission provided it is amended to change the implementation period from eight to five months and to include Rate Schedule 103 customers. They also agreed that for purposes of the WNA Clause, fixed gas costs will be allocated to the various customer classes as set forth in Schedule IV attached to the stipulation entered into between the Company and the Public Staff. Finally, they agreed to work together on an appropriate form to be used to meet the requirements of Section IV of the WNA Clause. [Exhibit JHM-2, p. 3, ¶ 5].

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 307-310

The Company and the Public Staff stipulated to the use of a 10% interest rate, which is to be compounded monthly, for the interest to be applied to deferred account No. 253. No other party introduced any evidence on this issue or questioned the use of the 10% interest rate.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 311-314

The Company and the Public Staff stipulated to the use in this proceeding of a pro forma commodity cost of gas and initial benchmark cost of gas of $2.50 per dekatherm and that the Company can increase its benchmark price in the manner set forth in Section II A of the PGA Clause. No other party introduced any evidence on this issue or questioned the use of the $2.50 cost of gas for these purposes.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 315-318

The Company and the Public Staff stipulated that Piedmont would conduct a study of deferred tax reserves as recommended by the Public Staff and that the study would be completed by the time of the filing of Piedmont's next general rate case or within two years, whichever occurs later. No other party introduced any evidence on this issue.

EVIDENCE IN SUPPORT OF FINDINGS AND CONCLUSIONS 319-323

The Company and the Public Staff stipulated that Piedmont would file monthly reports in the form set forth in Exhibit II to Public Staff witness Hoard's prefiled testimony and that these monthly reports would be in lieu of the quarterly reports Piedmont currently files with the Commission unless the Commission or the Commission Staff objects to discontinuing the filing of quarterly reports. No other party introduced any evidence on this issue.

The Commission uses the quarterly information now reported by Piedmont, and the Commission objects to discontinuing the filing of the quarterly reports. With respect to the filing of monthly reports, the Commission notes that the Public Staff proposed monthly reports in order to better monitor Piedmont. The Commission will initiate proceedings in the near future in order to provide for implementation of G.S. 62-133.4. The frequency and content of reports appropriate to monitor the State's LDCs in a uniform manner is a matter best determined as the Commission implements that statute. The Commission therefore concludes that Piedmont should continue to file quarterly reports for the present, subject to determination of the appropriate reporting as noted above.

IT IS, THEREFORE, ORDERED as follows:

1. That Piedmont Natural Gas Company, Inc., be, and is hereby, allowed to increase its rates and charges so as to produce an annual level of revenue of $272,857,407 (including $986,193 of other operating revenue and assuming a $2.50 cost of gas) from its North Carolina customers based on the Company's level of test period operations. Such amount represents an increase of $9,664,433 above the level of revenues that would have resulted from rates in effect during the test period.

2. That the rates shown on Late Filed Schedule V Revised Corrected be, and the same are hereby, approved effective for service rendered on and after the date of this Order.

3. That the service regulations proposed by the Company, except as modified herein, be, and the same are hereby, approved effective for service rendered on and after the date of this Order.

4. That the revised PGA Clause proposed by Piedmont, except as modified herein, be, and the same is hereby, approved effective for service rendered on and after the date of this Order, on a provisional basis, in the sense

hereinabove provided, pending implementation of G.S. 62-133.4. Any monies so collected which are associated with additional pipeline capacity and storage shall be placed in a deferred account pending further Order of the Commission.

5. That the Weather Normalization Adjustment Clause as set forth in the stipulation between the Company and the Public Staff, be, and the same is hereby, approved effective for service rendered on and after the date of this Order.

6. That Piedmont shall file appropriate tariffs, including its service regulations, PGA Clause and Weather Normalization Adjustment Clause, in accordance with the provisions of this Order, not later than ten (10) days from the date of this Order.

7. That Piedmont shall send the notice attached hereto as Appendix A to its customers as a bill insert in its next billing cycle after the date of this Order.

8. That Piedmont shall conduct a study of its deferred tax reserves by the time its files its next general rate case or within two years, whichever is later.

9. That Piedmont shall apply an interest rate of 10%, compounded monthly, to the Deferred Account No. 253.

ISSUED BY ORDER OF THE COMMISSION
This the 22nd day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 309

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Piedmont Natural)
Gas Company, Inc., for an Adjustment of) PUBLIC NOTICE
its Rates and Charges)

The North Carolina Utilities Commission issued an Order allowing Piedmont Natural Gas Company, Inc., to increase its rates and charges by approximately $9.7 million annually or 3.08% overall effective July 22, 1991.

The Company's application for a rate increase was filed with the Commission on December 21, 1990. Piedmont initially requested an increase of approximately $25.3 million but adjusted its request to approximately $9.7 million at the hearings. Such adjustment was the result of an overall settlement and stipulation entered into between the Company and the Public Staff of the Utilities Commission regarding the amount of the proposed increase.

In its application, Piedmont stated that it has been adding customers, making capital investments in its utility properties, and obtaining new long-term capital from the sales of securities at unprecedented levels. The reasons cited by Piedmont in support of a rate increase were to allow it to maintain its facilities and services in accordance with the reasonable requirements of its customers, to compete in the market for capital funds on fair and reasonable terms and to produce a fair profit for its stockholders.

The Commission notes that the increase to specific classes of customers will vary in order to have each customer class pay its fair share of the cost of providing service.

A typical year-round residential customer's annual bill will increase approximately 4.4% based upon 92 therms of gas usage.

In allowing the increase, the Commission found that the approved rates would provide Piedmont, under efficient management, an opportunity to earn an approximate 11.43% rate of return on its rate base devoted to providing utility service in North Carolina. This is a reduction from 11.63% approved in the Company's last general rate case.

DOCKET NO. G-21, SUB 293
DOCKET NO. G-21, SUB 295

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for an Adjustment of Its Rates and Charges) ORDER GRANTING PARTIAL RATE INCREASE

HEARD: Thursday, September 26, 1991, at 11:00 a.m., Council Chambers, City Hall, 433 Hay Street, Fayetteville, North Carolina

Thursday, September 26, 1991, at 7:00 p.m., Assembly Room, County Administration Building, 320 Chestnut Street, Wilmington, North Carolina

Friday, September 27, 1991, at 11:00 a.m., Council Chambers, City Hall, 207 East King Street, Kinston, North Carolina

Tuesday, October 8, 1991, at 9:30 a.m., through Friday, October 11, 1991, Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina

BEFORE: Commissioner Sarah Lindsay Tate, Presiding, and Commissioners Julius A. Wright and Allyson K. Duncan

APPEARANCES:

For North Carolina Natural Gas Corporation:

Donald W. McCoy, Alfred E. Cleveland, and Jeffrey N. Surles, Attorneys at Law, McCoy, Weaver, Wiggins, Cleveland & Raper, Box 2129, Fayetteville, North Carolina 28302

For the Public Staff:

David T. Drooz and Gisele L. Rankin, Staff Attorneys, Public Staff - North Carolina Utilities Commission, P. O. Box 29520, Raleigh, North Carolina 27626-0520

For Carolina Utility Customers Association, Inc.:

Sam J. Ervin, IV, Attorney at Law, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P.A., P. O. Drawer 1269, Morganton, North Carolina 28655

For Public Works Commission of the City of Fayetteville:

Marland C. Reid, Attorney at Law, Reid, Lewis, Deese & Nance, P.O. Drawer 1358, Fayetteville, North Carolina 28302

For Federal Paper Board Company, Inc.:

Ralph McDonald and Cathleen M. Plaut, Attorneys at Law, Bailey & Dixon, P. O. Box 12865, Raleigh, North Carolina 27605-2865

For the City of Monroe:

John Milliken, Attorney at Law, Love & Milliken, Attorney at Law, P.O. Box 278, Monroe, North Carolina 28110
and
James N. Horwood, Cynthia S. Bogorad, and Kodwo P. Ghartey-Tagoe, Attorneys at Law Spiegel & McDiarmid, 1350 New York Avenue, N.W., Washington, D.C. 20005-4798

For Aluminum Company of America:

M. Toler Workman, Attorney at Law, LeBoeuf, Lamb, Leiby & MacRae, P. O. Box 31507, Raleigh, North Carolina 27622

BY THE COMMISSION: On May 8, 1991, North Carolina Natural Gas Corporation (NCNG, Company or Applicant) filed an application with the North Carolina Utilities Commission (Commission) in Docket No. G-21, Sub 293, seeking authority to adjust its rates and charges for natural gas service in North Carolina and to make certain changes to its rules, regulations and tariffs. NCNG asked that the proposed rates be effective on and after June 7, 1991. NCNG also requested the

Commission to authorize on an interim basis during the suspension period the recovery of certain gas costs which had been previously authorized in the October 31, 1990, order in Docket No. G-21, Sub 289.

On June 7, 1991, the Commission issued an Order declaring the matter to be a general rate case, suspending the proposed rates, granting the request for interim relief, scheduling public hearings in Fayetteville, Wilmington, Kinston, and Raleigh, establishing the test period, setting dates for the prefiling of testimony by parties, and ordering NCNG to mail and publish notice of the proposed increase.

On June 27, 1991, the Commission issued an Order rescheduling the hearing and amending the public notice.

Timely motions to intervene were made and allowed for the following parties: the Public Works Commission of the City of Fayetteville (PWC), the Aluminum Company of America (Alcoa), Federal Paper Board Company, Inc. (FPB), the City of Monroe (Monroe), and the Carolina Utility Customers Association, Inc. (CUCA). The Public Staff and the Attorney General also intervened, but the Attorney General withdrew from the case by Notice of Withdrawal filed October 7, 1991.

On September 14, 1991, NCNG filed affidavits of publication from newspapers throughout its service territory confirming the publication of the Notice of Hearing required by the Commission's Order of June 7, 1991.

On September 16, 1991, the Commission issued an Order that consolidated NCNG's depreciation study in Docket No. G-21, Sub 295, with the rate case in Docket No. G-21, Sub 293.

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

<u>Fayetteville:</u> Vincent Chase
Alice Kiley
Robert Jorgenson
Howard Godfrey

<u>Wilmington:</u> No witnesses

<u>Kinston:</u> David R. Holdridge

<u>Raleigh:</u> Charles Wilson Whitley, Jr.

Effective October 1, 1991, the Commission approved changes in the cost of gas for NCNG, pursuant to G.S. 62-133.4, by Order in Docket No. G-21, Sub 296. The Public Staff and NCNG addressed the effects of these gas cost changes on the rate case in supplemental testimony and exhibits filed on October 8, 1991.

Witnesses for the parties presented evidence in Raleigh beginning on October 8, 1991.

NCNG presented the testimony and exhibits of the following witnesses: Calvin B. Wells, President and Chief Executive Officer of NCNG; Gerald A. Teele, Senior Vice President of NCNG; Victor L. Andrews of EBA Associates, Inc.; and Peter S. Huck of American Appraisal Associates.

Monroe presented the testimony and exhibits of Lynn A. Keziah, Mayor of the City of Monroe; and P. Wilson Crook, Director of Utilities for the City of Monroe.

Alcoa presented the testimony of Maynard F. Stickney, consultant for Alcoa.

PWC presented the testimony and exhibits of Steven K. Blanchard, Director of Generation and Power Supply for the Public Works Commission of Fayetteville.

The Public Staff presented the testimony and exhibits of the following witnesses: John Robert Hinton, staff financial analyst; Eugene H. Curtis, Jr., staff public utilities engineer; Windley E. Henry, staff accountant; Katherine A. Fernald, staff accountant; and James G. Hoard, staff accounting supervisor.

NCNG presented rebuttal testimony and exhibits from the following witnesses: Calvin B. Wells; Gerald A. Teele; Victor L. Andrews; and Frederick W. Hering, Analyst of Rates and Budget for NCNG.

Based on the application, the testimony and exhibits, and the entire record in this proceeding, the Commission makes the following

FINDINGS OF FACT
GENERAL MATTERS

1. North Carolina Natural Gas Corporation (NCNG) is duly organized as a corporation under the laws of the State of Delaware and is duly authorized to do business in the State of North Carolina. Its principal office and place of business is in Fayetteville, North Carolina.

2. NCNG is a public utility engaged in the business of providing retail natural gas service to the public in North Carolina.

3. NCNG is subject to the jurisdiction of the North Carolina Utilities Commission, and is lawfully before this Commission upon its application for an adjustment in its rates and charges for natural gas service pursuant to G.S. 62-133.

4. The test period for this rate case is the 12 months ended September 30, 1990, adjusted for certain known changes based upon circumstances occurring no later than the close of hearing.

5. NCNG is providing an adequate quality of natural gas service to its customers.

6. NCNG originally requested a decrease in annual revenues of $1,541,451, which consisted of (1) an increase in non-gas costs of $7,198,637, (2) an increase in fixed charges from pipelines and producers of $12,298,316, and (3) a decrease in commodity costs of $21,038,404.

7. In supplemental updated testimony and exhibits filed on July 29, 1991, the Company revised its request to ask for a $3,491,626 decrease in annual revenues. This request consisted of (1) an $8,797,718 increase in non-gas costs, (2) a $10,379,367 increase in fixed charges from pipelines and producers, and (3) a decrease in commodity costs of $22,668,711.

8. In supplemental revised updated testimony and exhibits filed on October 8, 1991, NCNG further revised its request to ask for an increase of $6,708,591 in annual revenues. The change from the prior requested decrease to this requested increase was primarily due to the fact that certain gas cost changes that NCNG had initially proposed to make in the rate case were approved prior to the rate case, in Docket No. G-21, Sub 296, pursuant to G.S. 62-133.4.

9. On the basis of certain adjustments made during the course of the hearing, the Company's final request as set forth in its proposed order was for an increase in the level of annual operating revenues of $6,565,541. In contrast, the Public Staff's final recommendation was for an increase in the level of annual operating revenues of $1,968,451.

INTERIM RELIEF

10. As part of its application in this proceeding, NCNG requested that the Commission issue an order specifically re-approving as interim relief in this general rate case the 50% recovery of Columbia CDS demand charges previously approved by an Order of the Commission issued in Docket G-21, Sub 281 and recovery of Transco's Southern Expansion demand charges approved by Commission Order dated October 31, 1990, in Docket G-21, Sub 289, as recoveries of such demand charges have been revised in subsequent PGA proceedings.

11. In its June 7, 1991, Order in this docket, the Commission granted NCNG's request for interim relief subject to refund if not ultimately approved in this final Order. No party presented any evidence that the recovery by NCNG of Columbia demand costs and Southern Expansion demand costs is not just and reasonable in order to meet the needs of its customers and the Commission finds such recovery to be just and reasonable.

VOLUMES

12. The appropriate level of adjusted sales and transportation volumes for use herein is 43,606,833 dekatherms (dts), which is comprised of 12,224,664 dts of transportation volumes and 31,382,169 dts of sales volumes.

13. Actual test period sales and transportation volumes were 42,293,467 dts.

14. Actual test period volumes should be adjusted to reflect normal weather conditions.

15. Growth in sales and transportation volumes to high priority customers should be accounted for without a corresponding decrease in volumes to industrial customers.

16. The appropriate volume level for lost and unaccounted for gas is 436,986 dts.

17. The appropriate level of Company use gas is 148,082 dts.

18. The gas supply required to generate the appropriate sales level is as follows:

	Dts
Sales and Transportation	43,606,833
Less: Transportation	(12,224,664)
Sales	31,382,169
Company Use	148,082
Lost and Unaccounted For	436,986
Gas Supply	31,967,237

COST OF GAS

19. The appropriate level for total fixed cost of gas is $19,854,112.

20. It is appropriate to classify producer reservation fees as a commodity cost of gas item, instead of a fixed cost of gas item.

21. The total commodity cost of gas is $80,854,234.

22. It is reasonable to price summer spot gas at $2.200/dt, winter spot gas at $2.800/dt and Columbia CDS gas at $3.1470/dt.

23. Fuel retainage gas has been incorporated in the estimated purchased price of gas used to compute the Base Cost of Gas. Therefore, fuel retainage gas should not be specifically set out in determining the commodity cost of gas and Base Cost of Gas.

24. The appropriate Base Cost of Gas is an annual rate of $2.5293 per dekatherm. This rate is computed by dividing the annual commodity cost of gas of $80,854,234 by the annual gas supply volumes of 31,967,237 dekatherms.

25. The appropriate cost of Company use gas is $374,544.

26. It is proper to reclassify Company use gas from Cost of Gas Expense to Operation and Maintenance (O&M) Expenses.

27. The reasonable level for the total cost of gas is $100,333,802, determined as follows:

Commodity cost of gas	$ 80,854,234
Fixed cost of gas	19,854,112
Less: Company use gas	(374,544)
Total Cost of Gas	$100,333,802

DEPRECIATION RATES

28. NCNG proposed an increase in its overall depreciation rates from 3.17% to 4.36%. NCNG proposed increasing its depreciation rate for Account 376 (Mains) from 2.40% to 3.05% with a proposed net negative salvage of 30%. NCNG proposed increasing its depreciation rate for Account 380 (Services) from 3.71% to 7.79% with a proposed net negative salvage of 150%.

29. Accounts 376 and 380 show substantial overrecoveries of the net negative salvage actually incurred and booked by NCNG as compared to the theoretical salvage. NCNG is being overcompensated on an annual basis under the current net negative salvage rates. Current ratepayers should not be charged an overly burdensome amount for future retirements for the benefit of future ratepayers.

30. It is inappropriate at this time to increase the depreciation rates for Accounts 376 and 380.

RATE BASE

31. The appropriate level of gas in storage for use in this proceeding is $4,874,675.

32. Gas in storage should be priced at the current rolling average prices.

33. LNG gas in storage should not be increased by a 2% fuel factor.

34. The appropriate level of materials and supplies for use in this proceeding is $2,006,019.

35. The appropriate level of investor funds advanced for operations for use in this proceeding is $1,403,718.

36. For purposes of this proceeding, per books cost of service should be adjusted for an extraordinary uncollectibles provision related to an industrial customer which is significant and nonrecurring in determining cash working capital requirements.

37. An amount representing manager's working funds should be included in working capital.

38. A portion of prepaid pension expense should be allocated to non-utility operations.

39. For purposes of this proceeding, accrued interest on customer deposits should be deducted from working capital.

40. It is appropriate to treat Transco refunds as cost-free capital.

41. For purposes of this proceeding, accounts payable in the amount of $476,815 related to materials and supplies, plant in service and construction work in progress should be deducted from working capital.

42. The appropriate level of miscellaneous deferred credits to be excluded from the working capital investment is $945,271.

43. The appropriate level of gas utility plant in service for use in this proceeding is $186,182,781.

44. It is appropriate to allocate $598,217 of general plant to non-utility operations. It is also appropriate to allocate $112,114 for accumulated depreciation, $28,244 for depreciation expense, and $59,150 for accumulated deferred taxes to non-utility operations.

45. The operation and maintenance expenses of $288,095 that would have been charged to construction during the test year based on the allocations recommended by Public Staff witness Fernald should be included in rate base. Also matching adjustments for these costs should be made to accumulated depreciation and depreciation expense.

46. The appropriate level of accumulated depreciation for use in this proceeding is $58,864,822.

47. The appropriate level of accumulated deferred income taxes for use in this proceeding is $18,299,972.

48. It is appropriate to calculate accumulated deferred income taxes related to additional plant based on actual additions instead of estimated additions.

49. Accumulated deferred income taxes related to the gain on sale of land of $129,143 should not be included in rate base.

50. North Carolina Natural Gas Corporation's reasonable rate base used and useful in providing service is $114,712,630, consisting of gas plant in service of $186,182,781, gas in storage of $4,874,675 and materials and supplies of $2,006,019, reduced by accumulated depreciation of $58,864,822, other working capital items of $1,186,051 and accumulated deferred income taxes of $18,299,972.

OPERATING REVENUES

51. The appropriate level of end-of-period revenues for use in this proceeding is $143,002,977, which is comprised of $142,650,447 of sales and transportation revenues and $352,530 of miscellaneous revenues.

52. It is appropriate to reflect revenues from residential customers that will be added on the distribution projects that were completed in September 1991.

53. No revenues will be reflected for the transmission projects completed in September 1991 due to the lack of information available for calculating an appropriate level of revenues that would properly account for the effect of the IST mechanism.

OPERATING REVENUE DEDUCTIONS

54. The appropriate level of operation and maintenance expenses for use in this proceeding is $15,732,812.

55. The Public Staff adjustment to allocate $21,334 of payroll expenses to affiliates is reasonable and appropriate for purposes of this proceeding.

56. It is appropriate to adjust workers' compensation expense for both the known increase in base rates of 18.9% and the known decrease in the experience modification factor of 36%.

57. It is appropriate to apply customer growth to maintenance accounts.

58. It is appropriate to include $10,450 paid to Glenn Jernigan and Associates for legislative liaison activities for purposes of this proceeding.

59. The charitable contributions of $114,736 included by the Company in operating revenue deductions should be excluded.

60. The total rate case expense related to this proceeding is $144,333.

61. The total rate case expense should be amortized over 3 years.

62. Property insurance should be allocated to non-utility operations based on the Massachusetts formula.

63. Industry association dues and convention expenses should be allocated to non-utility operations based on the Massachusetts formula.

64. It is appropriate to adjust for inflation through August 31, 1991. This results in an inflation factor of 6.375%.

65. The overall methodology used by the Public Staff to calculate inflation is proper for this proceeding.

66. The appropriate level of inflation, for purposes of this proceeding, is $287,868.

67. It is appropriate to reduce advertising expenses by $102,842 in order to remove costs incurred for advertising designed to compete with other sources of energy and designed to promote the Company's image.

68. The appropriate level of depreciation expense for use in this proceeding is $5,955,335.

69. Based on the other findings and conclusions set forth in this Order, the appropriate level of general taxes for use in this proceeding is $6,498,716.

70. Payroll taxes should be allocated to affiliated companies based on payroll distribution.

71. Property taxes should be calculated based on actual plant additions instead of estimated additions.

72. Based on the other findings and conclusions set forth in this Order, the appropriate level of state income tax expense under present rates for use in this proceeding is $720,067.

73. The representative rate for the state income tax surtax is 3%, based on a three-year average period. This results in an overall state income tax rate of 7.9825%.

74. Based on the other findings and conclusions set forth in this Order, the appropriate level of federal income tax expense under present rates for use in this proceeding is $2,544,691.

75. The Public Staff's proposed adjustment of $23,957 for interest on excess deferred income taxes is inappropriate and not reasonable for purposes of this proceeding.

76. The overall level of operating revenue deductions under present rates appropriate for use in this proceeding is $131,704,468.

CAPITAL STRUCTURE AND COST OF CAPITAL

77. The proper capital structure found reasonable for use in this proceeding is as follows:

	Amount	(%)
Long-Term Debt	$ 55,030,000	51.0
Common Equity	52,867,006	49.0
Total	$107,897,006	100.0

78. The proper cost of long-term debt is 9.68%.

79. The specific business risks associated with (1) NCNG's high percentage of industrial load that is fuel switchable, and (2) the transition to open access do not justify an additional equity risk premium in this case.

80. Estimates of the cost of common equity capital derived by use of the DCF methodology and the risk premium methodologies, including the CAPM, are entitled to be given weight in reaching a final determination in this case.

81. The DCF methodology presented by the Public Staff should be given the greater weight in determining the cost of common equity capital for purposes of this proceeding.

82. The proper cost of common equity capital for purposes of this proceeding is 12.7% and includes no allowance for down markets or flotation costs.

83. Based on the foregoing findings with respect to the proper capitalization ratios and the appropriate cost rates for each component of

capital reflected in that capitalization, the overall fair rate of return that the Company should be allowed an opportunity to earn on its rate base is 11.16%.

ADDITIONAL REVENUE REQUIREMENT

84. NCNG should be authorized to increase its annual level of operating revenues by $2,564,512. After giving effect to the approved increase, the annual revenue requirement for NCNG is $145,567,489, which will allow the Company a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

FACILITIES CHARGES AND MISCELLANEOUS FEES

85. Both the Company and the Public Staff have proposed increases in NCNG's facilities charges as follows:

Description	Present	Proposed
Rate 1 - Heat Only	$ 7.00 (9 months per year)	$ 7.50 (12 months per year)
- All Other Customers	$ 5.00	$ 6.50
Rate 2	$ 9.00	$ 11.00
Rate NGV - Per Vehicle	$ 1.00	$ 1.50
Rate 3A	$100.00	$125.00
All Other Industrial Rate Schedules	$200.00	$250.00

86. As no party opposed the increases in facilities charges shown above, the Commission concludes that the facilities charges for NCNG's rate schedules should be increased as proposed by the Company and the Public Staff.

87. Both the Company and the Public Staff proposed increases in NCNG's reconnection fees to restore service as shown below:

Description		Present	Proposed
Residential	September - January	$19.42	$43.69
	February - August	19.42	29.13
Commercial	September - January	$29.13	$58.25
	February - August	29.13	38.84

88. As no party opposed the increases in NCNG's reconnection fees shown above, the Commission concludes that the reconnection fees should be increased as proposed by the Company and the Public Staff.

89. The Company proposed an increase in its returned check fee from $5.00 to $15.00. As no party opposed NCNG's proposal, the Commission concludes that it is reasonable to increase the returned check fee to $15.00.

90. The Commission concludes that a "connect fee" is appropriate for new residential and commercial customers and should be set at $15 per additional

customer. This charge should be included in NCNG's tariffs for these customer classes and should be explained in NCNG's rules and regulations.

91. The estimated revenue from connect fees is $48,000, which is calculated by multiplying the $15 connect fee by estimated annual new customer additions of 3,200.

COST OF SERVICE AND RATE DESIGN

92. NCNG and the Public Staff are the only parties that performed and presented estimated cost-of-service studies.

93. Aside from the sales and revenue levels, the only material difference between the estimated cost-of-service studies presented by NCNG and the Public Staff relate to the treatment of distribution mains.

94. While estimated cost-of-service studies are subjective and judgmental, they are useful as a guide in designing rates.

95. A number of factors must be considered when rates are designed. These factors include the cost of service; the value of service to the customer; the type and priority of service received by the customer and, if the service is interruptible, the frequency of interruptions; the quantity of use; the time of use; the manner of service; the competitive conditions in the market place related to the acquisition of new customers; the historic rate differentials between the various classes of customers; the revenue stability of the utility; and the economic and political factors which are inherent in the ratemaking process, including the encouragement of expansion.

96. Rates based solely on one or more estimated cost-of-service studies are not reasonable for purposes of this proceeding.

97. The rates of return among NCNG's customer classes are not directly comparable.

98. NCNG's residential customers have a very limited ability to switch to alternate fuels without making significant capital investment in new equipment. In addition, they bear the risk of being required to make up margin losses resulting from NCNG's negotiations with industrial customers included in the IST.

99. The ability of the large commercial and industrial customers to negotiate and force NCNG to meet the prices of their alternative fuels gives them bargaining power not enjoyed by other classes of customers. This justifies a higher rate of return for such customers.

100. It is not appropriate to use alternate fuel prices as a cap on industrial rates.

101. Rates based entirely upon equalized rates of return among customer classes are not reasonable for purposes of this proceeding.

102. Gas costs have decreased 25% from 1983 through 1990. During the same time period, the rates of the industrial classes of customers have decreased 31%, and the rates of the residential class have decreased only 4%.

103. Because the rates of the residential class of customers have not decreased in the same proportion as the cost of gas has decreased, the residential class has been paying a steadily increasing percentage of NCNG's non-gas costs.

104. The Commission has historically concluded (and been upheld by the North Carolina Supreme Court) that specific customer classes should not receive rate increases which, in light of all the surrounding facts and circumstances, result in "rate shock."

105. In determining whether a specific class increase results in "rate shock," the Commission considers the utility's historic rate design, as well as other relevant facts and circumstances.

106. Placing a 34% rate increase on the residential class as proposed by the Company would place an unreasonable burden on that class relative to their historical rates. The rate design approved in this proceeding will not result in "rate shock" to any class of customers served by NCNG.

107. The Company proposed to establish the following new rate schedules to reflect two-part, demand/commodity rates for certain large firm service customers:

Description	Sales Rate Schedule	Companion Transportation Rate Schedule	Contract Demand (Dt/Day)
General Service to Municipalities and Public Authorities	RE-2	T-6	41,000
Service to Large Float Glass Furnaces (Priority 5)	9	T-5	9,500
Military Bases with Contract Demand >3,000 Dt/Day	10	T-10	5,200

108. Changes experienced in the natural gas industry following the enactment of the Natural Gas Policy Act of 1978 and the development of "open access" interstate pipelines have resulted in significant alterations in the cost of purchasing and obtaining the delivery of natural gas for resale. Two of the changes experienced have been the increase in fixed gas costs and the decline in commodity costs.

109. With increasing fixed gas costs, two-part rates with separately stated demand charges more accurately reflect the cost of firm service than pure commodity costs.

110. Many of the rate design factors applying to NCNG's large commercial and industrial customers apply with equal force to the industrial customers of the Cities.

111. Industrial customers on the Cities' municipal systems have the ability to switch to alternate fuels and therefore have the ability to negotiate rates.

112. Rate Schedule RE-2 is intended to reflect an approximate composite of the various classes of customers served by the Cities.

113. The imposition of a demand charge reduces the risk involved in serving a particular class of customers.

114. New Rate Schedules RE-2 and T-6 with a separate demand and commodity charge should be established for General Service to Municipalities and Public Authorities.

115. The maximum daily quantity to which the separate demand charge will be applied under Rate Schedules RE-2 and T-6 for those customers who have not entered into a service agreement with the Company shall be based on the customer's highest daily take from the Company on the Company's peak day during the last five years. The applicable maximum daily quantity shall be recalculated annually.

116. RE-2 customers will pay for gas taken in excess of their maximum daily quantity on Rate Schedule E-1 only in the event that gas is taken when the customer would otherwise be curtailed. Gas taken in excess of contract demand levels but not subject to curtailment will be paid for on a 100% load factor basis.

117. The Company's proposed rates for Rate Schedules 9 and T-5, Service to Large Float Glass Furnaces, including the $7.00 per Dt demand charge, were determined by contract negotiations between the Company and its customer, Libby-Owens-Ford Company (L-O-F).

118. L-O-F is the largest consumer of natural gas in the State of North Carolina.

119. L-O-F entered into a 15-year contract for firm service from NCNG beginning in May 1990.

120. L-O-F operates at an annual load factor of 95% to 100%.

121. The agreement between NCNG and L-O-F provides for interruption of natural gas service in the event of "force majeure, the demands of the Company's residential, commercial and other higher priority customers under the Commission's approved curtailment plan, other conditions beyond the control of the Company or Customer, lack of sufficient delivery capacity, and when provided by the Rules and Regulations of the North Carolina Utilities Commission."

122. The proposed rates for Rate Schedules 9 and T-5 are just and reasonable.

123. New Rate Schedules 9 and T-5 with a separate demand and commodity charge should be established for Service to Large Float Glass Furnaces.

124. Under NCNG's existing rate structure, the Fort Bragg military base has been served under Rate Schedule 1 for residential use in barracks and Rate Schedule 6 for boiler fuel requirements.

125. Prior to this proceeding, the authorities at Fort Bragg requested NCNG to consolidate their service into one rate schedule in a manner similar to the existing schedules for municipal gas distribution systems.

126. The Company's proposed rates for Rate Schedules 10 and T-10, Service to Military Bases with Contract Demand Greater Than 3,000 Dt per day, including the $7.00 per Dt demand charge, recognize the unique characteristics of serving a large military base.

127. New Rate Schedules 10 and T-10 with a separate demand and commodity charge should be established for Service to Military Bases with Contract Demand Greater Than 3,000 Dt per day.

128. The curtailment provisions in the Company's Service Rules and Regulations shall be modified to limit the curtailment of customers below their contract demand level to force majeure situations.

129. It would be premature for the Commission to approve capacity assignment programs in this proceeding under which the Company would assign to a customer capacity in an interstate pipeline. Such capacity assignment programs would require approval of the Federal Energy Regulatory Commission and, at the time of the hearing, no such program had been approved.

130. The establishment of the new Rate Schedules RE-2, T-6, 9, T-5, 10, T-10 including the contract demand levels and demand rates proposed by the Company as midified in this Order are just and reasonable.

131. NCNG has proposed to modify Rate Schedule 6 to make it available to any customer having requirements for natural gas for boiler fuel or electric power generation over 15,000 therms per day which meet the criteria set forth in North Carolina Utilities Commission Rule R6-19.2 for priorities 7, 8 and 9.

132. NCNG's principal electric generation customer is currently served under Rate Schedule 6; for that reason, NCNG's proposed modification of Rate Schedule 6 merely "codifies" existing practice.

133. PWC proposed that a separate rate class should be established for NCNG's electric utility customers.

134. PWC noted that PWC uses gas as boiler fuel and constitutes a significant percentage of the volumes taken under Rate Schedules 6, T-1 and S-1, accounting for approximately half of the Rates 6 and T-1 combined test year volumes and about 30% of the test year volumes in Rates 6, T-1 and S-1.

135. PWC testified that approximately 50% of its electric load and resulting gas usage is attributable to residential electric customers.

136. The PWC did not propose specific rates or terms and conditions, other than a lower rate of return.

137. It is not appropriate to establish a separate rate schedule for electric utility customers at this time.

138. The rates approved by this Order are just and reasonable and do not result in any unjust or unreasonable discrimination or preference between or within classes of customers.

FIXED GAS COST RECOVERY RATES

139. The Public Staff's methodology of allocating fixed gas costs is more reflective of how the costs are incurred. This methodology results in fixed gas cost recovery rates that range from $0.94/dt for a Rate Schedule 1 (residential) customer to $0.22/dt for a Rate Schedule 6 (large industrial) customer.

140. The fixed gas costs recovery rates proposed by the Public Staff are appropriate for purposes of calculating fixed gas cost recovery in Riders A and B and for the implementation of the Weather Normalization Adjustment factor (Rider C) approved in this Order.

SUMMER/WINTER RATE DIFFERENTIALS

141. The Public Staff, NCNG and CUCA all supported the concept of summer/winter differentials in filed tariff rates.

142. The Company proposed a summer/winter differential based upon the seasonal differences in the commodity cost of gas.

143. The Public Staff maintained that a summer/winter differential in tariff rates should reflect the fact that costs other than the commodity cost of gas (such as storage fees and injection, withdrawal, and capacity charges) experience seasonal swings. Increased costs related to increased demand in the winter should be assigned to the various rate classes and included in the approved tariff rates.

144. Seasonal differences in the commodity cost of gas generally apply to all classes of customers and historically have been recognized through PGA proceedings.

145. NCNG did not offer compelling reasons to support its proposal to reflect only seasonal changes in the commodity cost of gas and no seasonal changes in demand-related costs in the filed tariff rates.

146. The summer/winter differentials proposed by the Public Staff are just and reasonable, except for Rate Schedules 9 and T-5.

TRANSPORTATION RATES

147. The Commission has approved full margin transportation rates for all of the natural gas local distribution companies operating in North Carolina and rejected arguments that cost-based rates are required.

148. The Commission consistently has calculated full margin transportation rates by subtracting the annual cost of gas, applicable gross receipts taxes and any temporary increments or decrements from the sales rate schedule under which the transportation customer would otherwise be buying natural gas from NCNG.

149. The basic premise underlying the concept of full margin transportation rates as previously approved by the Commission is the LDC should be neutral as to whether a customer transports or buys natural gas under a filed tariff rate. In order for an LDC to be neutral, a transportation customer should pay the same fixed costs it would pay as a sales customer.

150. All but one of NCNG's customers who pay transportation fees to transport their own supply of natural gas have contracts for interruptible service with an interstate pipeline(s).

151. Transportation on the relevant interstate pipelines is unavailable in the winter except to customers with contracts for firm service because of capacity constraints on Transco's and Columbia's interstate pipelines.

152. Interruptions can occur at other times, such as when Transco is replenishing its supplies in storage further north or when there is a hurricane in the Gulf of Mexico.

153. NCNG's transportation customers become NCNG's sales customers whenever they cannot transport their own supplies of natural gas, unless they switch to their alternate fuels.

154. The services performed by NCNG for a customer who transports are substantially the same as those performed for a sales only customer.

155. NCNG's proposed winter and summer Weighted Average Cost of Gas (WACOG) reflect's a seasonal differential in commodity costs.

156. Historically, changes in commodity costs have been handled using the Purchased Gas Adjustment.

157. The Public Staff maintains that some demand costs also vary by season and should be reflected in the summer/winter differentials.

158. The Company did not present a sufficiently compelling argument to convince the Commission to depart from historical rate design methodology.

159. The full margin transportation rates resulting from the adoption of the Public Staff's recommended methodology and Rate Schedule T-5 as filed by the Company are just and reasonable.

INDUSTRIAL SALES TRACKER

160. The Rider A Industrial Sales Tracker (IST) as proposed by the Public Staff in this proceeding is appropriate and should be included in the rate structure of the Company.

161. Demand and storage charges should be excluded from the IST base period margins, and the resulting amounts should be referred to as "base period gross profit."

162. The purpose of the IST is to stabilize the Company's gross profit margin on the sale and transportation of gas to industrial customers having heavy oil as their alternative fuel. The IST protects the Company against gross profit losses on transactions with IST customers. The IST also benefits core market customers when the price of heavy oil increases and/or IST volumes increase.

163. The base period gross profit amounts appropriate for Industrial Sales Tracker purposes shall be calculated by the Company based upon the provisions of this Order.

164. It is inappropriate to incorporate growth into the IST base period gross profit in this proceeding.

PURCHASED GAS ADJUSTMENT PROCEDURES

165. The Rider B Purchased Gas Adjustment (PGA) Procedures as proposed by the Public Staff in this proceeding are reasonable and appropriate on a provisional basis pending implementation of G.S. 62-133.4.

166. The PGA Procedures approved by the Commission herein account for all commodity costs of all gas supplies and services, and for all fixed costs of all gas supplies and services, including, on a provisional basis, the costs of additional capacity and storage. The approved PGA Procedures provide for a 100% true-up of all prudently incurred gas costs.

167. The Commission has initiated proceedings in Docket No. G-100, Sub 58, to set forth rules for implementing G.S. 62-133.4.

168. The PGA Procedures approved herein may be superseded by the procedures adopted in Docket No. G-100, Sub 58, to implement G.S. 62-133.4. Also, the issue of whether additional pipeline capacity and storage costs should be recovered in rates prior to NCNG's next rate case will be decided in Docket No. G-100, Sub 58, instead of in this Order. Any monies associated with additional pipeline capacity and storage should therefore be placed in a deferred account pending further order of the Commission.

169. The Company should compare the actual commodity cost of gas incurred, expressed on a per unit basis, with the Base Cost of Gas, and the per unit difference should then be multiplied by the volumes purchased, net of storage injections and withdrawals, to determine the underrecovery or overrecovery of commodity gas costs to be recorded in the Deferred Gas Cost Account.

170. The Company should compare the demand and storage charges collected in the Company's rates to the actual demand and storage charges incurred each month, and any difference should be recorded in the Deferred Gas Cost Account.

171. Adjustments to the Company's rates due to changes in demand and storage charges, and increments and decrements resulting from past demand and storage charge under or overrecoveries, should be computed on a flat per dekatherm basis.

172. Interest should be accrued each month on the average balance in the Deferred Gas Cost Account at the annual rate of 10%, compounded monthly.

173. The Company should record in the Deferred Gas Cost Account the margins earned by Cape Fear Energy Corporation for gas marketing or brokering services provided to transporting end users, less $.02 per dekatherm.

174. The Company should record in the Deferred Gas Cost Account all excess margins earned on sales of emergency gas to non-IST customers. The excess margins are computed by comparing all revenues received by the Company, less gross receipts taxes, to the revenue less gross receipts taxes which would have been received if the quantity of gas had been sold under the customer's regular rate.

175. The Company should record in the Deferred Gas Cost Account all additional margins earned on sales of gas to off-system entities, including Public Service Company of North Carolina. The additional margins are computed by comparing all revenue received by the Company, less the cost of gas and gross receipts taxes, to the revenue less the cost of gas and gross receipts taxes reflected for sales of gas to off-system entities included by the Commission in the cost of service in this proceeding.

176. The cost of service in this proceeding reflects $1,833,102 of revenue, $569,092 of cost of gas, and $59,026 of gross receipts taxes, for a margin of $1,204,984 related to sales of gas to off-system entities. The entire amount reflected in this proceeding includes sales of gas to Public Service Company of North Carolina, Inc.

177. The Company may negotiate with non-IST commercial and industrial customers on its sales and transportation rates to avoid the loss of deliveries to these non-IST customers. All margin loss from these customers shall be accumulated in the Deferred Gas Cost Account. Such margin loss shall be based on the Company's tariff rates.

178. The Company should true-up on an annual basis the gas costs associated with Company Use and Unaccounted For Volumes. This true-up should be computed by comparing the actual Company Use and Unaccounted For Volumes during the true-up period with the Company Use and Unaccounted For Volumes reflected in rates during the twelve-month true-up period, and multiplying the difference by the applicable Base Cost of Gas. The first annual true-up period shall be the year ending June 30, 1993.

179. The Company should maintain separate account categories for Deferred Gas Cost Account transactions that relate to (1) all customers, and (2) sales only customers.

180. The Company should analyze the balances in its present deferred gas cost accounts on a first-in, first-out basis consistent with the Commission's

definition of demand and storage charges and commodity gas costs set forth in the approved PGA Procedures. This analysis should be performed concurrent with the date of this Order.

WEATHER NORMALIZATION ADJUSTMENT

181. NCNG has requested approval of a Weather Normalization Adjustment factor (WNA) which will reduce variations in the Company's earnings and otherwise protect the Company from the adverse impacts of departures from normal weather.

182. The WNA will be in effect for the winter period for Rate Schedule 1 and 2 and for the weather sensitive portions of Rate Schedules RE-2 and 10.

183. NCNG's WNA should operate in the same manner (without a dead band) as the Weather Normalization Adjustment clause recently approved for Piedmont Natural Gas Company, Inc., and Public Service Company of North Carolina, Inc.

MISCELLANEOUS ACCOUNTING MATTERS

184. NCNG should prepare an accounting manual as recommended by the Public Staff and agreed to by the Company within three years from the date of this Order.

185. NCNG should undertake a study so as to determine an appropriate methodology to properly allocate employees' time spent on affiliated companies.

186. NCNG should prepare a square footage study during 1992 for the purpose of providing current data for allocating plant to non-utility operations.

187. NCNG should allocate on its books the expenses for payroll taxes, pension costs, group insurance, workers' compensation, accident and health, excess liability, and all other payroll related expenses to accounts based on the distribution of payroll within 60 days of the date of this Order.

188. NCNG should record non-utility taxes in non-utility accounts within 60 days of the date of this Order.

189. NCNG should use as its Allowance for Funds Used During Construction (AFUDC) rate the overall return on investment approved in this Order.

190. NCNG should account for fuel retainage costs associated with storage injections as a cost of gas in storage, as recommended by the Public Staff.

191. The $344,395 gain realized by NCNG on the sale of land should be flowed back to ratepayers over a period of three years through the gas cost deferred account after being grossed up for gross receipts tax.

192. Off-system sales to Public Service Company of North Carolina should be included in the regulatory fee calculation.

193. NCNG's lost and unaccounted for volumes should be trued up annually.

194. It is not appropriate that margins earned on sales of natural gas to CP&L for use in its Weatherspoon plant be placed in NCNG's gas cost savings deferred account.

RULES AND REGULATIONS

195. In its original prefiled testimony and exhibits, NCNG proposed certain modifications to its service regulations, including an increase in its reconnection fees, an increase in its charge for returned checks and revisions which primarily streamline the Rules and Regulations, eliminate certain redundancies, address transportation procedures, address procedures regarding billing errors, and clarify Company responsibility up to the point of delivery and customer responsibility on the customer's side of the delivery point.

196. As the Commission has previously found that it is reasonable for NCNG to charge a connection fee to new residential and commercial customers as proposed by the Public Staff, the Commission finds that a paragraph setting out the procedures for such a connection fee should be added to NCNG's General Rules and Regulations.

197. It is reasonable and appropriate for this Commission to approve in form a standard contract for service; however, the Company should have the option of entering verbal agreements with residential and commercial customers.

198. Section 15 of NCNG's proposed Rules and Regulations should be modified. The word "provide" should be changed to "extend its gas lines in order to provide."

199. NCNG's proposed Section 23 of its Rules and Regulations with regard to its responsibility beyond the delivery point should not be used to define the Company's potential tort liability. Paragraph 23 should be amended as recommended by the Public Staff.

200. The procedures concerning transportation imbalances set forth in Sections 45, 46 and 47 of the proposed General Rules and Regulations are necessary to discourage transportation imbalances continuing more than one calendar month after the month in which they occur and to prevent losses and gas scheduling problems to NCNG resulting from transportation customer imbalances.

201. Except for the modifications found to be appropriate herein, NCNG's proposed General Rules and Regulations as amended by the Public Staff and agreed to by the Company are just and reasonable.

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

The evidence supporting these findings of fact is contained in the verified application, the Commission's files and records regarding this proceeding, the Commission's Orders scheduling hearings, and the testimony and exhibits of the Company and the Public Staff. These findings of fact are essentially informational and uncontradicted.

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

The evidence supporting these findings is found primarily in the direct testimony of NCNG witness Wells, NCNG's application, and the Commission's Order dated June 7, 1991, in this docket. No party presented any evidence rebutting Mr. Wells' testimony on this issue or in opposition to the interim relief.

NCNG witness Wells testified that, if the Commission granted NCNG's request for interim relief by reapproving the rate adjustments relating to recovery of Columbia's CDS demand charges and Transco's Southern Expansion demand charges, such relief would not result in a change in rates during the suspension period ordered by the Commission in this docket. Mr. Wells testified that NCNG wanted such interim relief as additional legal authority for rates approved by the Commission in Docket G-21, Sub 289, but appealed by CUCA. The Commission granted Piedmont Natural Gas Company, Inc., similar interim relief in Docket G-9, Sub 309, when Piedmont found itself in the same circumstances with respect to recovery of Southern Expansion costs.

These FERC-approved charges are additional wholesale costs which NCNG had to incur in order to obtain deliveries of additional volumes of gas to its system. Mr. Wells testified that all of NCNG's sales customers benefitted from the delivery of these additional gas volumes to its system, which could not have occurred if NCNG had not paid the demand charges. During the 1990-91 winter period, approximately eighty-five percent (85%) of the gas delivered to NCNG through Southern Expansion went to IST customers, with all margin earned on such volumes being credited to non-IST core market customers. Both Mr. Wells and ALCOA witness Stickney testified that additional volumes delivered through Columbia and Southern Expansion decreased curtailments to industrial customers.

Public Staff witness Hoard testified that the Public Staff has no problem with NCNG's recovery of Southern Expansion demand costs in this rate case.

No party presented any evidence that the recovery by NCNG of Columbia demand costs and Southern Expansion demand charges approved by Commission Order dated October 31, 1990, in Docket G-21, Sub 289, as recoveries of such demand charges have been revised in subsequent PGA proceedings.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 12-18

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Teele and Public Staff witness Curtis. Mr. Teele offered evidence that the actual test period volumes were 42,293,467 dekatherms (G-1 Minimum Filing Requirements, Item 10, Worksheet A-1). After adjusting this test period volume of 42,293,467 dekatherms for weather normalization, movement of volumes to the appropriate rate schedules, and customer growth, the Public Staff and NCNG agreed that the level of sales and transportation volumes appropriate for use in this general rate case is 43,606,833 dekatherms.

Although the Company and Public Staff agreed on the level of sales and transportation volumes, the parties did differ on the volume level of gas supply required. Below is a comparison in dts of the Company and Public Staff calculations of the gas supply volume level required.

	Company	Public Staff	Difference
Sales and Transportation	43,606,833	43,606,833	-0-
Less: Transportation	(12,224,664)	(12,224,664)	-0-
Sales	31,382,169	31,382,169	-0-
Company Use	148,082	148,082	-0-
Lost and Unaccounted for	436,986	436,986	-0-
Fuel retainage	119,954	-0-	(119,954)
Gas Supply	32,087,191	31,967,237	(119,954)

As illustrated above, the only issue relating to the appropriate level of gas supply on which the Company and Public Staff differ is fuel retainage. In the Evidence and Conclusions for Finding of Fact No. 23, the Commission has concluded that fuel retainage gas has been incorporated in the estimated purchase price of gas used to compute the Base Cost of Gas. Therefore it is consistent to exclude fuel retainage volumes from the calculation of gas supply volumes.

Based on the foregoing, the Commission concludes that the appropriate level of gas supply volumes required in dts is calculated as follows:

Sales and Transportation	43,606,833
Less: Transportation	(12,224,664)
Sales	31,382,169
Company Use	148,082
Lost and Unaccounted for	436,986
Gas Supply	31,967,237

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19-27

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Teele and Public Staff witnesses Fernald, Hoard, and Curtis. The levels of cost of gas proposed by the Company and the Public Staff in their final positions are set forth in the schedule below:

Item	Company	Public Staff	Difference
Commodity cost of gas	$ 81,118,135	$ 80,854,234	$ (263,901)
Fixed cost of gas	19,854,112	19,854,112	
Less: Company use gas	(388,972)	(374,544)	14,428
Total Cost of gas	$100,583,275	$100,333,802	$ (249,473)

FIXED GAS COSTS

As can be seen from the above schedule, the Company and the Public Staff agree as to the level of fixed gas costs. Some questions arose during the hearing, however, regarding whether producer reservation charges should be considered a fixed or commodity gas cost.

During the CUCA cross-examination of Public Staff witness Hoard, CUCA implied that producer reservation charges should not be assigned to the rate classes on a flat per dekatherm basis, as Mr. Hoard had recommended. Mr. Hoard explained:

"Since reservation charges involve only the gas supply, we would consider those to be part of the commodity cost of gas. You're not getting any capacity, pipeline capacity. So it wouldn't seem like you would want to include that with fixed gas costs. It should be commodity."

Public Staff witness Curtis testified earlier that he reflected producer reservation charges in the commodity cost of gas as part of the spot market price.

Company witness Teele agreed with the Public Staff that producer reservations charges relate to gas supply and not to pipeline capacity. Mr. Teele tempered his agreement somewhat by explaining that he reflected the producer reservation charges as a commodity item simply to be consistent with the Piedmont Natural Gas Company, Inc. (Piedmont) and Public Service Company of North Carolina, Inc. (Public Service) rate case stipulations. He noted that he considered producer reservation charges to be a fixed cost.

During the cross-examination of Company witness Teele, CUCA suggested that each commodity gas cost service should be evaluated and allocated to rate classes on a service-specific basis, not a flat per dekatherm (volumetric) basis. Following is an excerpt from CUCA's cross-examination of Company witness Teele which illustrates CUCA's implied position:

Q. But even among sales rate customers there are different categories of firmness, aren't there, Mr. Teele?

A. Oh, yes, sure.

Q. And I believe you testified earlier that you would consider these reservation fees that we have been discussing to have been incurred for the benefit of the Company's firm market; is that right?

A. Primarily but then, again, you have to consider our total markets and, obviously, we aren't going out and buying firm gas for boiler fuel customers but, you know, depending on who is being served on a particular day. Any particular customer class can get some benefit.

Q. But typically, is it not true that those gas suppliers that you buy under long-term contract for which these reservation fees are paid are, in theory, intended to make sure that you have an adequate gas supply to meet the requirements of your firm customers?

A. That's why I said it was supply security and means firm core market customers, yes.

Q. And if those costs were recovered from all sales rate customers on a volumetric basis as has been the case in your billed versus filed proceedings, or however you want to categorize them, a greater proportion of those reservation fees are going to be shifted to lower priority customers such as customers taking sales rate case under your boiler fuel schedule?

A. That would be the effect, that's right.

The Commission concludes that the Public Staff's classification of the producer reservation charges as commodity costs is appropriate. These charges are part of the cost of gas supply. Even though they are billed on a fixed basis and give NCNG firm rights to gas supply, they nonetheless should be classified as commodity costs because they are in fact a component of the total price of the gas commodity NCNG purchases.

The Commission rejects the suggestion by CUCA's counsel that certain commodity costs, such as producer reservation fees, should be recovered from particular customer classes. There is no basis in evidence for determining which commodity costs should be allocated to which customer classes even if the Commission did approve of the concept; which it does not.

The Commission's conclusions here are consistent with the treatment of these issues in the recent Piedmont and Public Service rate cases.

Since the parties agree that the amount of fixed gas costs, exclusive of producer reservation charges, is $19,854,112, and the Commission has determined that producer reservation charges should be excluded from fixed gas costs, the Commission concludes that the appropriate level of fixed gas costs for use in this proceeding is $19,854,112.

COMMODITY GAS COSTS

Public Staff witness Curtis and Company witness Teele priced out their respective gas supply volume levels utilizing a summer spot gas price of $2.20 per dekatherm, a winter spot gas price of $2.80 per dekatherm, and a Columbia CDS gas rate of $3.1470 per dekatherm. The $263,901 difference in the commodity cost of gas between the parties relates entirely to their differing treatments of 119,954 dts of fuel retainage gas.

The Company reflected 119,954 dts for fuel retainage gas as a component of its annual gas supply purchases used in computing its annual WACOG (or Base Cost of Gas). The Company priced-out this fuel retainage gas at $2.20 per dekatherm, its estimated summer spot cost of gas, resulting in an increase in commodity gas costs of $263,901.

The Public Staff did not specifically set out fuel retainage gas in its Base Cost of Gas calculation. Public Staff witness Hoard reasoned that the $2.20 per dekatherm summer spot gas price is only an estimate of the future commodity cost of gas and is trued-up to actual through the PGA accounting procedures. In effect, the Public Staff incorporates fuel retainage gas costs in the estimated purchase price of gas used to compute the Base Cost of Gas.

Public Staff witness Hoard also pointed out that fuel retainage costs were not specifically set out as a component of the commodity cost of gas in the recent Piedmont or Public Service rate cases. Mr. Hoard testified that the Base Cost of Gas was set at $2.50 per dekatherm in those cases based on broad estimates of the future commodity cost of gas.

The Commission notes that Mr. Hoard's approach of treating fuel retainage costs as part of the estimated price per dekatherm in the Base Cost of Gas is consistent with the Company's approach to producer reservation fees, which are also not set out as a separate cost of gas item. Mr. Teele admitted that fuel retainage costs would be recovered through the Rider B cost of gas procedures whether or not it was listed as a separate cost of gas.

The Commission finds that fuel retainage gas should not be specifically set out in determining the commodity cost of gas and Base Cost of Gas. Fuel retainage gas has instead been incorporated in the spot price of gas used to compute the Base Cost of Gas. This approach to handling fuel retainage gas is reasonable, allows the Company full recovery of its actual incurred commodity cost of gas, and is consistent with the manner in which fuel retainage was treated in the recent Piedmont and Public Service rate cases.

The Commission concludes that the appropriate level of the commodity cost of gas is $80,854,234. The Base Cost of Gas is calculated by dividing cost of gas by the 31,967,237 dts of supply found to be necessary to generate the appropriate sales level in Finding of Fact No. 18. The Commission therefore concludes that the appropriate Base Cost of Gas for the annual period is $2.5293/dt.

COMPANY USE GAS

The second area of difference between the Company and the Public Staff is Company use gas. The difference of $14,428 is due to the difference in the Base Cost of Gas proposed by the Company and the Public Staff. Both the Company and the Public Staff have deducted the cost of Company use gas from Cost of Gas Expenses and reclassified it to Operations and Maintenance Expenses.

In the Evidence and Conclusions for Finding of Fact No. 17, the Commission found that the appropriate level of Company use gas is 148,082 dekatherms. Therefore, based on the Base Cost of Gas of $2.5293/dt determined to be appropriate in this proceeding, the Commission concludes that the appropriate cost of Company use gas is $374,544. The Commission also finds it appropriate to reclassify the cost of Company use gas to Operations and Maintenance Expense.

SUMMARY

Based upon the foregoing, the Commission concludes that the appropriate level of cost of gas for use in this proceeding is $100,333,802, made up of the following components:

Commodity cost of gas	$ 80,854,234
Fixed cost of gas	19,854,112
Less: Company use gas	(374,544)
Total cost of gas	$100,333,802

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 28-30

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Huck and Public Staff witness Curtis.

Mr. Huck conducted a study and analysis for the purpose of developing appropriate appraisal depreciation rates for NCNG's depreciable gas property. He recommended that NCNG adopt an increased Company composite depreciation rate of 4.36%. The major components of his recommended increase were to Account 376 (Mains) and Account 380 (Services). For Account 376, he recommended an increase from NCNG's present accrual rate of 2.40% to 3.05%, and for Account 380, he recommended an increase from 3.71% to 7.79%. The bulk of the increase is related to the net negative salvage (cost of removal less salvage value) for these two accounts. An increase in net negative salvage for Account 376 from negative 20% to negative 30% and an increase in net negative salvage for Account 380 from negative 45% to negative 150% were recommended.

Mr. Curtis testified that he disagreed with the recommended depreciation rates for Accounts 376 and 380 and recommended that the depreciation rates for these accounts be left at their current levels. He demonstrated by two different calculations, which are shown on Curtis Exhibits J and K, that NCNG is currently substantially over-recovering its net negative salvage based on the actual net negative salvages recorded on its books for these two accounts. He further testified that the most recent study Piedmont has on file with the Commission, which is dated 1989, shows a 2.55% depreciation rate for Account 376 and a 2.21% rate for Account 380. Public Service has in effect a depreciation rate of 2.40% for Account 376 and a rate of 3.71% for Account 380. The maximum net salvage for the other two North Carolina distribution companies is a negative 15% for Account 376 and a negative 30% for Account 380. According to witness Curtis, if NCNG used the maximum net salvage used by the other two companies, it would have a decrease in depreciation expense, rather than the proposed increase of $1,940,304, which increases to $2,169,319 with NCNG's plant update. In Mr. Curtis' opinion, the depreciation rates for Accounts 376 (Mains) and 380 (Services) for the North Carolina local distribution companies should be similar.

On cross-examination by the Public Staff, Mr. Huck agreed that it would cost more to bury, and therefore to dig up, a main or service in soil that was heavy clay or rocky than it would in lighter, less rocky soil. He testified that he has some general knowledge of North Carolina's geography and generally conceded that Piedmont and Public Service are located in areas of the State where the soil is generally heavy clay and rocky, as well as becoming mountainous in the western part of the State compared to the mostly sandy soil in NCNG's territory. While he accepted subject to check that the Commission had approved the depreciation rates for Piedmont and Public Service set out in Mr. Curtis' testimony, he was not very sure of the background in terms of whether they were based on company sponsored studies or whether they had actually been approved by the Commission.

Based on the evidence in this record it appears that NCNG is being over-compensated on an annual basis under the current net negative salvage rates and over-recovering the net negative salvage actually incurred and booked by NCNG as compared to the theoretical salvage. The Commission concludes that while the depreciation rates for these two accounts need not be exactly the same for the three large local distribution companies operating in North Carolina, they should be similar. There is no justification in the record for increasing NCNG's net negative salvage and therefore the depreciation rates for these two accounts as proposed by the Company. The Commission concludes that current ratepayers should not be charged an overly burdensome amount for future retirements for the benefit of future ratepayers. The depreciation rates recommended by the Public Staff are fair and reasonable and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 31-42

The evidence supporting these findings of fact are contained in the testimony and exhibits of Company witnesses Teele and Hering and Public Staff witnesses Henry, Fernald, and Hoard. The following chart summarizes the final amounts recommended by the Public Staff and the Company as the proper level of working capital allowance to include in NCNG's rate base in this proceeding:

Item	Company	Public Staff	Difference
Natural gas in storage	$ 6,012,597	$ 4,874,675	$(1,137,922)
Materials & supplies	2,006,019	2,006,019	-0-
All other working capital items:			
Investor finds advanced for operations	1,354,541	1,146,226	(208,315)
Mininmum bank balances	218,850	150,000	(68,850)
Sales tax accruals	(43,975)	(43,975)	-0-
Equal pmt. plan collections	(493,324)	(493,324)	-0-
Customer deposits	(1,463,060)	(1,463,060)	-0-
Prepaid pension expense	1,063,439	957,414	(106,025)
Accrued interest on customer deposits	-0-	(218,211)	(218,211)
Transco refunds	-0-	(125,377)	(125,377)
Accounts payable - materials & supplies, plant in service, & CWIP	(87,132)	(476,815)	(389,683)
Deferred credits	(477,855)	(945,271)	(467,416)
All other working capital items	71,484	(1,512,393)	(1,583,877)
Total working capital investment	$ 8,090,100	$ 5,368,301	$(2,721,799

UNCONTESTED ITEMS

The Company and the Public Staff are in agreement as to the appropriate amount of sales tax accruals and equal payment plan collections to be deducted in determining the working capital allowance. No other party presented evidence on these issues; therefore, the Commission concludes that the amounts for sales tax accruals and equal payment plan collections to be deducted from rate base are $43,975 and $493,324, respectively.

In its final position filed on October 8, 1991, the Company revised its amounts of materials and supplies and customer deposits to accept adjustments proposed by the Public Staff. As a result of these revisions, the Public Staff and the Company are in agreement as to the appropriate level of materials and supplies to be included in rate base and the proper amount of customer deposits to be deducted from rate base. There being no evidence to the contrary, the Commission concludes that $2,006,019 should be added to working capital for material and supplies, and customer deposits of $1,463,060 should be deducted from working capital.

NATURAL GAS IN STORAGE

The first area of disagreement between the Company and the Public Staff relates to natural gas in storage. Company witness Teele, in his rebuttal testimony, testified that the appropriate level of gas in storage to include in rate base is $6,012,597. Public Staff witness Fernald testified that the appropriate level of gas in storage to include in rate base is $4,874,675. There is a difference of $(1,137,922) between the level of gas in storage recommended to be included by Mr. Teele and the final position recommended by Ms. Fernald. This difference is composed of the following items:

Item	Amount
Adjustment to reflect rolling average prices	$(1,113,726)
2% LNG fuel adjustment factor	(24,196)
Total	$(1,137,922)

Adjustment to Reflect Rolling Average Prices

The first item is the Public Staff adjustment to price gas in storage at the current rolling average prices. In its original filing, the Company priced gas in storage at the summer spot gas "benchmark", which is an estimate of future gas prices. The Public Staff made an adjustment to price the gas in storage at the actual current rolling average prices.

Company witness Teele testified that the rolling average cost used by the Public Staff is the rolling average cost in inventory at July 31, 1991, when gas prices were at their lowest level in eleven years. Mr. Teele also testified that the Company's book inventories used by the Public Staff do not include the cost of transportation of the WSS supplies when they are withdrawn in the wintertime. Mr. Teele stated that when the WSS gas comes out of storage, the Company will pay another 40 to 50 cents to deliver it to the city gate.

Mr. Teele also stated that the costs for gas in storage in the recent Piedmont and Public Service rate cases were substantially higher than what the Public Staff is recommending in this case. Mr. Teele stated that he did not believe the Public Staff was consistent with the approach in these two cases.

Mr. Teele acknowledged in cross-examination that the rolling average prices used by the Public Staff are the actual prices the Company has invested in gas in storage. Mr. Teele also acknowledged that the Public Staff is putting the current value on this rate base item while the Company is proposing to use an estimated future value.

Mr. Teele also acknowledged that Public Staff Teele Rebuttal Cross-Examination Exhibit Number 1 showed that the Public Staff recommendation in this case of $1.78 price per dt is much closer to the $1.81 price per dt in the Public Service case than NCNG's recommendation of $2.20. Mr. Teele did indicate that he did not know if the $1.81 price per dt on the exhibit was the stipulated amount in the Public Service case. Mr. Teele also testified that Piedmont's gas in storage included certain demand costs that were not included in gas in storage for NCNG or Public Service.

The Commission concludes that gas in storage should be priced at the current rolling average prices as recommended by the Public Staff. These prices represent the actual investment the Company has in gas in storage.

The Commission rejects the Company's assertion that an estimated future price of $2.20 should be used. Future gas prices are unknown and any estimates of these gas prices are speculative. Gas prices when gas is placed in storage next summer could be higher, lower, or the same as current prices. It is appropriate to use actual gas prices to determine a representative level of gas in storage. This is consistent with the Commission's treatment of all other rate base items, such as plant and materials and supplies.

The Commission rejects the Company's assertion that the Public Staff price per dt for WSS is understated since transportation costs that are paid when gas is withdrawn from WSS are not included. Transportation costs for withdrawing WSS, GSS, and LNG are included in cost of gas, not gas in storage. Neither the Public Staff nor NCNG have claimed that these costs should be included in gas in storage. It should be noted that WSS costs, a component of demand and storage costs, are trued-up monthly in accordance with the PGA procedures approved herein. Therefore, there are no carrying costs applicable to these WSS transportation costs.

The Company contended that the Public Staff treatment of gas in storage for NCNG was inconsistent with the recent Piedmont and Public Service rate cases. The Commission finds that this contention is incorrect. In the Public Service case, Docket No. G-5,Sub 280, the testimony of Public Staff accountant Kris Au Hinton, filed August 15, 1991, states on page 10 that "The Company has included in rate base the 13-month average balance of gas in storage as reflected on its books for the test year." (Emphasis added.) Ms. Hinton indicated that she used the rolling average inventory price. In either event, both parties used an actual cost of gas in storage, not an estimated future cost. Furthermore, in that same docket, Hinton Exhibit I, Schedule 2-3, shows that Public Service had priced its gas inventory at $6,839,091 for 3,781,840 dts. That calculates to a price of gas in storage of $1.81 per dt. Thus, the Public Service price is much closer to the Public Staff's recommendation of $1.78 per dt in this case than NCNG's recommendation of $2.20 per dt.

Along the same lines, the May 7, 1991, stipulation between Piedmont and the Public Staff in Docket No. G-9, Sub 309, states at paragraph 2 (j) that the gas in storage dollar amount "was computed in the method set forth in the prefiled testimony of the Public Staff." The prefiled testimony of Public Staff witness Hoard in that docket states on page 14 that he priced gas in storage with "the current rolling average inventory rate." This is consistent with the Public Staff's recommendation in the present case. The Commission concludes that the gas in storage in this case should be priced at the current rolling average price as recommended by witness Fernald.

2% LNG Fuel Factor

Company witness Teele proposed an adjustment to increase LNG inventory by a 2% fuel factor. Mr. Teele explained what this gas is used for, how the 2% factor is calculated, what data it is based on, and how the gas is accounted for in response to a Public Staff discovery request as follows:

> "The 2% fuel factor for LNG represents the vaporizer fuel used when gas is vaporized from the tank into the pipeline. Our engineers state that the 2% factor is a design factor based on the plans and specifications of the plant. This fuel gas applies only to the vaporization operations when gas is converted from a liquid back into a gaseous state. The fuel gas is metered and the actual amount last year was just under 2%. The cost of the fuel is charged to account #842.1 in LNG operations expenses. For the test year, the per books amount of the vaporizer fuel is $29,253, and the pro forma amount included in the test year, updated, is $33,130. Because the gas is metered separately and charged to O&M expenses, it is an element of Company Use gas but is not Lost and Unaccounted For."

Public Staff witness Hoard testified that Mr. Teele's adjustment is inappropriate because the Company has no carrying costs associated with LNG vaporization costs, and increasing LNG gas in storage by the 2% fuel factor would allow the Company to earn a return on investment that does not exist. Mr. Hoard explained that vaporization costs would be incurred and recovered during the winter season. Mr. Hoard also pointed out that the cost of vaporization was reflected in end-of-period O&M expenses as Company Use gas, and therefore would be trued-up to actual annually under his recommended PGA Procedures. The Commission notes that it has accepted these PGA Procedures as set forth elsewhere herein.

The Commission finds on the basis of Mr. Hoard's testimony that the Company has no working capital funds tied-up in unrecovered vaporization costs. Therefore, we reject the Company's proposal to increase LNG gas in storage by a 2% fuel factor.

Based on the foregoing, the Commission concludes that the level of gas in storage for use in this proceeding is $4,874,675.

INVESTOR FUNDS ADVANCED FOR OPERATIONS

The next area of disagreement between the Company and the Public Staff relates to investor funds advanced for operations. Company witness Hering, in his rebuttal testimony, testified that the appropriate level of investor funds advanced for operations to include in rate base is $1,354,541, while Public Staff witness Henry proposed $1,146,226 as the appropriate level for these funds. The difference of $(208,315) is due to a difference of $49,177 related to a "claim of right" refund and its related tax effects and $(257,492) related to an unusual charge to bad debts expense regarding the account of a large industrial customer.

Public Staff witness Henry testified, "In the Company's lead-lag study, revenues, gross receipts tax, and state and federal income taxes were adjusted to reflect non-recurring "claim of right" adjustment. In addition, the bad debt provision was also adjusted by the Company for an extraordinary write-off made during the test year. Since it has been the Commission's policy that the per books cost of service should be used in calculating cash working capital, the effects of the claim of right adjustment and the extraordinary write-off should be removed to reflect per books amounts."

Company witness Hering also testified, the claim of right was nonrecurring, and the level of bad debt expense was extraordinarily high. Mr. Hering stated that use of the "per books" amounts for these items distorts the results of the lead-lag study, and therefore they should be adjusted.

On cross-examination, Witness Henry was questioned concerning a portion of the Order in Docket No. G-21, Sub 255, the Company's last general rate case. Mr. Henry read the following part, "The Commission believes and reaffirms its opinion expressed in the past rate case proceeding that per books is a reasonable and appropriate basis for the calculation of a working-capital allowance in all but the most unusual of circumstances." Witness Henry admitted that the Commission provides for exceptions to the per book method but stated that he makes no exceptions regardless of the uniqueness of the transaction.

The Commission concludes that the use of per books cost of service should be adjusted for the extraordinary uncollectibles provision related to an industrial customer which is substantial and nonrecurring. However, the Commission is not persuaded that the "claim of right" refund is so extraordinary or significant so as to warrant departure from the use of the per books amount in calculating investor funds advanced for operations.

Based upon the foregoing, the Commission concludes that a reasonable and representative level of investor funds advanced for operations for use in this proceeding is $1,403,718.

MANAGER WORKING FUNDS

The next area of difference between the Company and the Public Staff is the level of minimum bank balances to be included in determining the working capital allowance. Company witness Teele, in his July 26, 1991, updated testimony, testified that the appropriate level of minimum bank balances to include in rate base is $218,850. Public Staff witness Henry testified that the appropriate level of minimum bank balances to include in rate base is $150,000. The $(68,850) difference between the parties results from Mr. Henry excluding managers' working funds from minimum bank balances.

Mr. Henry testified that managers' working funds are petty cash funds and checking accounts used to make change for customers and pay authorized bills. Mr. Henry stated that payments from these funds are expenses on the Company's books and are fully accounted for in its lead/lag study. Mr. Henry testified that these managers' funds are the same as the funds in the Company's regular operating checking account, except that they are located in checking accounts and petty cash funds in various district offices. Mr. Henry testified that no amount should be included in working capital for these managers' funds because no accounts, other than minimum bank balances, are included in working capital for funds in the Company's regular checking account.

On cross-examination, Mr. Henry agreed that a part of the managers' funds are used for making change; however, he stated that the amounts necessary for this purpose would be nominal. Mr. Henry also agreed that he had not considered any time lapse for the reimbursement of the funds by the home office.

The Commission agrees with the position advocated by NCNG that it maintains accounts for its managers at 23 service offices in order to fund adequately the day-to-day operations at each location and, as such, such amounts should be included as a component of working capital.

The Commission concludes that the managers' funds of $68,850 are not properly accounted for in the lead/lag study and should be included in the working capital requirement as minimum bank balances, and that the appropriate amount of minimum bank balances to include as a component of the allowance for working capital is $218,850.

PREPAID PENSION EXPENSE

The next difference between the Company and the Public Staff is the amount of prepaid pension expense to include in rate base. Public Staff witness Henry testified that the Company increased rate base to reflect the difference between the amount expensed and the amount funded by the Company since FASB 87 was adopted in 1986. Mr. Henry stated that a portion of this prepaid pension expense relates to non-utility operations. Mr. Henry testified that he allocated 9.97% or $106,025 of the prepaid pension expenses to non-utility operations. The 9.97% is based on payroll distribution percentage proposed by Public Staff witness Fernald and accepted by the Company.

The Company did not offer any evidence in rebuttal to the Public Staff's adjustment.

The Commission agrees with Mr. Henry that a portion of the prepaid pension expense should be allocated to non-utility operations. Certainly the pension plan covers employees performing both utility and non-utility duties; therefore, it is entirely appropriate to assign a portion of this cost to non-utility operations. The Commission also concludes that 9.97% is a reasonable allocation factor for assigning these costs to non-utility operations.

The Commission therefore concludes $106,025 of the prepaid pension expense should be assigned to non-utility operations, and that the appropriate level of prepaid pension expense to include as a component of the allowance for working capital is $957,414.

ACCRUED INTEREST ON CUSTOMER DEPOSITS

The next item of difference concerns accrued interest on customer deposits. Mr. Henry testified that the Company placed a zero lag on interest on customer deposits in its lead/lag study. He stated that as a result of placing a zero lag on interest on customer deposits, NCNG's study reflects a cash working capital requirement greater than its actual need. Mr. Henry stated that either an appropriate lag should have been determined for interest on customer deposits or the accrued liability for interest on customer deposits should be deducted from rate base. Mr. Henry testified that he reduced rate base by the average accrued liability for interest on customer deposits to preclude an overstatement of the cash working capital requirement.

The Company, in its proposed order, pointed out that its treatment of this item is consistent with the Commission approved lead/lag study in its last general rate case.

The Commission agrees with Mr. Henry that an appropriate lag should have been determined for interest on customer deposits in the Company's lead/lag study or the average accrued liability for interest on customer deposits should be deducted from rate base. The Commission therefore concludes that $218,211 of accrued liability for interest on customer deposits should be deducted from rate base.

TRANSCO REFUNDS

The next difference between the Company and Public Staff is Transco refunds in the amount of $125,377. Public Staff witness Henry deducted these Transco refunds from rate base as cost-free capital. The Company did not treat these refunds as cost-free capital.

Company witness Teele, in his rebuttal testimony, testified that the refunds were nowhere to be found on the Company's books and, indeed, the funds were spent many years ago for additional plant, as dividends to shareholders, or other general corporate purposes. Mr. Teele stated that the refunds should not be allowed as a permanent rate base reduction in the same way that book assets, such as land, are included in rate base.

Public Staff witness Henry testified that in prior NCNG rate cases, the Commission has concluded that it is appropriate to treat these refunds as cost-free capital supplied by ratepayers. Mr. Henry stated that in order to prevent ratepayers from paying any return on this cost-free capital, the Commission, in NCNG's last rate case, Docket No. G-21, Sub 255, found that it was proper to reduce rate base by the net of tax refunds of $125,377 and also to remove the refunds from the common equity portion of the Company's capital structure. Mr. Henry testified that since these Transco refunds could not be distributed to the utility's customers because it was impractical to identify the exact customers who paid those monies, NCNG will be in possession of this cost-free capital permanently.

The Commission reaffirms its position taken in NCNG's last general rate case, Docket No. G-21, Sub 255, that the Transco refunds in question should be treated as cost-free capital. Mr. Teele did not contend that these refunds were not cost-free capital. He merely stated that the funds were spent for additional plant, paid out as dividends to shareholders or used for other general corporate purposes and should not be deducted from rate base. The Commission rejects this argument. It matters not how the refunds were spent. It does matter that the refunds represent cost-free capital which was not provided by the debt and equity investors of the Company and the only acceptable ratemaking treatment of this cost-free capital, given the rulings of the courts, is to deduct it from rate base and deduct it from the equity component of the capital structure to prevent ratepayers from paying a return on any of this cost-free capital.

Based on the evidence presented by both parties on this issue and taking judicial notice of court rulings and prior orders regarding Transco refunds, the Commission concludes that it is appropriate to treat these refunds as cost-free capital and reduce rate base by the $125,377 net of tax amount of these Transco refunds. This conclusion is consistent with the Commission's treatment of the same Transco refunds in adopting an appropriate capital structure.

ACCOUNTS PAYABLE

The next area of difference between the Company and the Public Staff is the level of accounts payable to be deducted in determining the working capital allowance. Company witness Teele, in his October 8, 1991, revised updated testimony, testified that the appropriate level of accounts payable to be deducted from rate base is $87,132. Public Staff witness Henry testified that the appropriate level of accounts payable to deduct from rate base is $476,815. The difference of $389,683 is detailed in the chart below.

Item	Company	Public Staff	Difference
Accounts payable - materials & supplies	$87,132	$ 87,132	$ -0-
Accounts payable - plant in service	-0-	8,585	8,585
Accounts payable - CWIP	-0-	381,098	381,098
Total accounts payable	$87,132	$476,815	$389,683

Materials and Supplies

In its rebuttal testimony and its final position filed on October 8, 1991, the Company accepted the amount of accounts payable related to materials and supplies recommended by the Public Staff. There being no evidence to the contrary, the Commission concludes that accounts payable in the amount of $87,132 related to materials and supplies should be deducted from rate base.

Plant in Service and CWIP

The remaining difference results from the Public Staff deducting accounts payable related to plant in service and construction work-in-progress (CWIP) from rate base.

Company witness Hering, in his rebuttal testimony, testified that it is inappropriate to compare the use of "30-day money" to an asset with a 30-year life. Mr. Hering stated that the time frame that an asset is supported by accounts payable would represent .27% of its life, and the remaining life of that asset is supported by the Company's overall capital structure.

Public Staff witness Henry, in his prefiled testimony, testified that the Company has included the entire amount of plant in service in rate base as if it were financed by capital supplied entirely by the Company's investors. Mr. Henry stated that a portion of plant in service is actually financed by accounts payable which means that NCNG's creditors are financing a portion of the Company's investment in plant.

Public Staff witness Henry testified that the Company calculates Allowance for Funds Using During Construction (AFUDC) on construction costs, and eventually includes this amount in rate base. Mr. Henry stated that included in the Company's AFUDC base are construction costs supported by accounts payable. This means that NCNG's creditors are financing a portion of construction costs, while at the same time, a return on those costs, to be paid by ratepayers in the future, is being accrued.

The Commission does not agree with Company witness Hering. While it is true that accounts payable are paid monthly, it is also true that each month new accounts payable will be incurred which relate to plant in service and CWIP; therefore, there will always be a level of accounts payable supporting plant in service and CWIP. Further, Mr. Hering's logic fails completely when applied to CWIP. CWIP for a natural gas company is traditionally short lived. This is particularly true for "services." The Commission agrees with Public Staff witness Henry on the deduction of the accounts payable supporting CWIP from rate base. It would be unfair and unreasonable for the ratepayers to pay a return on CWIP which is supported by vendors of the Company. One of the accepted methods employed to recognize the cost-free capital provided by vendors is to deduct the accounts payable supporting CWIP from rate base. This would be a reasonable result even if the "30-day money" of accounts payable did not or could not be used to finance "30-year assets," since that "30-day money" is still cost-free capital for NCNG.

Finally, the Commission notes that Mr. Henry's recommendation is consistent with the approach taken in the final order in Docket No. E-22, Sub 314, which is North Carolina Power's most recent rate case. That order states at page 24:

> "the Commission concludes that accounts payable applicable to construction and nuclear fuel should be deducted from rate base in determining the proper allowance for working capital for use in this proceeding."

Based on the foregoing, the Commission concludes that accounts payable of $8,585 related to plant in service and accounts payable of $381,098 related to CWIP should be deducted from rate base. The total amount of accounts payable which should be deducted from rate base is $476,815.

DEFERRED CREDITS

The final area of difference between the Public Staff and the Company involves the amount of miscellaneous deferred credits that should be deducted from rate base. Company witness Teele, in his October 8, 1991, revised updated testimony, testified that the appropriate level of deferred credits to deduct from rate base is $477,855.

Public Staff witness Henry testified that the appropriate level of deferred credits to deduct from rate base is $945,271. The difference of $467,416 results from the Public Staff deducting unpaid medical claims, stock purchase plan, and option compensation and dividends as deferred credits in addition to what the Company has deducted. The chart below summarizes the $467,416 difference between the amount recommended by Company witness Teele in testimony and the final position recommended by Public Staff witness Henry.

Item	Company	Public Staff	Difference
Deferred directors' fees	$155,250	$155,250	$ -0-
Deferred compensation	272,905	272,905	-0-
Unpaid medical claims	-0-	349,789	349,789
Edgecombe County payments	49,700	49,700	-0-
Stock purchase plan	-0-	63,482	63,482
Stock Option plan accruals	-0-	54,145	54,145
Total deferred credits	$477,855	$945,271	$467,416

Undisputed Credits

The Company and the Public Staff are in agreement as to the appropriate amount of deferred directors' fees, deferred compensation and Edgecombe County payments to deduct from rate base as deferred credits. The Company revised its original filing to reflect the adjustments recommended by the Public Staff for these deferred credits. There being no evidence to the contrary, the Commission concludes that the total amounts of deferred credits related to deferred directors' fees, deferred compensation and Edgecombe County payments to be deducted from rate base are $155,250, $272,905 and $49,700, respectively.

Unpaid Medical Claims

The first item of deferred credits on which the parties differ is unpaid medical claims. Public Staff witness Henry testified that the Company failed to take into consideration, in its lead/lag study, the lag from the time health insurance payments are accrued and charged to expense until they are paid out as claims. Mr. Henry stated that over time the amounts expensed have exceeded the claims paid by the Company. Mr. Henry testified that unpaid medical claims represent the excess of the amount of medical claims expensed over the amount of medical payments paid.

NCNG did not offer any evidence in rebuttal to the Public Staff's adjustment.

The Commission concludes that there is a lag between the time health insurance premiums are accrued and the time that medical expense claims are paid. The Commission also concludes that this lag should be recognized in the determination of the cash working capital allowance. Since these unpaid medical expenses have not been considered in the lead/lag study, it is appropriate to deduct these amounts from rate base as cost-free capital. Therefore the Commission concludes that the unpaid medical claims of $349,789 should be deducted from rate base.

Stock Purchase Plan

The second difference in the treatment of deferred credits involves the Company's stock purchase plan. Mr. Henry testified that since the stock purchase plan has been reinstated by the Company and payroll deductions have begun, NCNG will again have this source of cost-free capital available. Mr. Henry stated that in order to recognize a reasonable and representative level of this cost-free capital, the rate base should be reduced by the average balance of the payroll deductions for the seven months of the test period that the plan was operative.

The Company did not provide any rebuttal testimony in opposition to Mr. Henry's adjustment.

The Commission concludes that there has been and will continue to be a source of cost-free capital associated with the stock purchase plan and that recognition of this cost-free capital is necessary. There is a definite time period between the time that employee payroll deductions are received by the Company and the date that the Company purchases stock for the employees with these funds. The Commission also believes that the average balance of the payroll deductions during the period the plan was in effect provides a fair and reasonable measure of the appropriate amount of this cost-free capital. The Commission therefore concludes that the $63,482 average balance of the stock purchase plan payroll deductions should be deducted from rate base.

Stock Option Plan Accruals

The final difference in the treatment of deferred credits between the Public Staff and the Company is the amount of the stock option plan accruals to be deducted from rate base. Public Staff witness Henry testified that NCNG accrues liabilities for its stock option plan. Mr. Henry stated that during the five years that the stock option plan will be in effect, amounts will be expensed for the stock option plan for which the Company will not have a cash outlay.

The Company did not offer evidence in rebuttal to this adjustment.

Since ratepayers are paying for expenses which the Company will not have to pay until some time in the future, the Commission concludes that rate base should be reduced by $54,145 to reflect this source of cost-free capital.

In summary, the Commission finds that $945,271 of deferred credits should be deducted from rate base.

SUMMARY CONCLUSION

Based on the foregoing, the Commission concludes that the appropriate level of working capital investment for use in this proceeding is $5,694,643, consisting of the following components:

Item	Amount
Natural gas in storage	$ 4,874,675
Materials & supplies	2,006,019
All other working capital items:	
Investor funds advanced for operations	1,403,718
Minimum bank balances	218,850
Sales tax accruals	(43,975)
Equal payment plan collections	(493,324)
Customer deposits	(1,463,060)
Prepaid pension expense	957,414
Accrued interest on customer deposits	(218,211)
Transco refunds	(125,377)
Accounts payable - materials & supplies, plant in service, & CWIP	(476,815)
Deferred credits	(945,271)
All other working capital items	(1,186,051)
Total working capital investment	$ 5,694,643

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 43-50

INTRODUCTION

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witnesses Teele and Hering and Public Staff witnesses Fernald, Henry, and Hoard. The amounts which the Company and the Public Staff presented as their final recommendations as to the Company's rate base are shown in the schedule below:

Item	Company	Public Staff	Difference
Gas plant in service	$186,182,781	$185,543,414	$ (639,367)
Accumulated depreciation	(60,838,395)	(58,726,707)	2,111,688
Net plant in service	125,344,386	126,816,707	1,472,321
Gas in storage	6,012,597	4,874,675	(1,137,922)
Materials and supplies	2,006,019	2,006,019	-
All other working capital items	71,484	(1,512,393)	(1,583,877)
Accumulated deferred income taxes	(18,425,303)	(18,261,819)	163,484
Total rate base	$115,009,183	$113,923,189	$(1,085,994)

In Evidence and Conclusions for Finding of Fact No. 31, the Commission concluded that the appropriate level of gas in storage is $4,874,675.

In Evidence and Conclusions for Finding of Fact No. 34, the Commission concluded that the appropriate level of materials and supplies for use in this proceeding is $2,006,019.

In Evidence and Conclusions for Findings of Fact Nos. 31-42, the Commission concluded that the appropriate level of all other working capital items for use in this proceeding is $(1,186,051).

GAS PLANT IN SERVICE

The first area of difference between the Company and the Public Staff is gas plant in service. The difference of $(639,367) is composed of the following items:

Item	Amount
Allocation of general plant to non-utility operations	$(351,272)
Capitalization of O&M expenses	(288,095)
Total	$(639,367)

Allocation of General Plant to Non-Utility Operations

The first item is the Public Staff adjustment to allocate $949,494 of general plant to non-utility operations. Public Staff witness Fernald testified that although a portion of general plant is used to support non-utility operations, NCNG did not allocate any general plant investment to non-utility operations.

In his rebuttal testimony, Company witness Teele agreed with the Public Staff's allocation of general plant to non-utility operations except for the following accounts:

Account Number	Description
39200	Transportation Equipment
39400	Tools and Work Equipment
39500	Laboratory Equipment
39600	Power Operated Equipment
39700	Communication Equipment
39900	CNG Fueling Station
39910	CNG Fueling - Conversion Vehicles

Witness Teele testified that these items are not used by merchandising and jobbing operations, and that propane has its assets listed separately in non-utility accounts. During cross-examination, the Public Staff questioned witness Teele about the communications equipment and the transportation equipment. Mr. Teele testified that the majority of the cost is for radios and towers for communication between Fayetteville and the construction offices, and that the only communication equipment used by merchandising would be a couple of telephones in the General Office.

Witness Teele further testified that merchandising and jobbing do not have any vehicles included in the transportation account. The reason they do not have any vehicles included is that all such vehicles are leased and these operating expenses are then allocated to merchandising and jobbing. Propane does have their own vehicles and they are appropriately listed as non-utility plant.

According to witness Teele, the reason merchandising and jobbing do not have any vehicles listed on the balance sheet is that the vehicles are leased and as stated, such costs are allocated to these.

Witness Teele also testified that accounts such as tools and work equipment are not used in merchandising, and that any such items for propane operations are recorded in non-utility accounts.

The Commission agrees with the position of NCNG that these accounts were not used for non-utility operations and, accordingly, should not be so allocated.

The Commission therefore concludes that the appropriate amount of general plant to allocate to non-utility operations is $598,222,as proposed by the Company.

Consistent with this adjustment, the Commission concludes that it is appropriate to make matching adjustments to allocate $112,114 of accumulated depreciation, $28,244 of depreciation expense, and $59,150 of accumulated deferred income taxes to non-utility operations.

Capitalization of O&M Expenses

The next item is the Company adjustment to capitalize $288,095 of operation and maintenance expenses. In her testimony, Public Staff witness Fernald allocated some expenses based on payroll distribution. This allocation will result in less costs being charged to operating expenses and more costs being charged to construction and non-utility operations in the future. The Company agreed with the Public Staff's adjustment, but proposed in testimony filed on the opening day of the hearing that the test year expenses that would have been charged to construction if the Public Staff's methodology had been used during the test year should be included in plant in this proceeding.

Company witness Teele stated that the Company will have to make an accounting entry that debits CWIP or plant and credits O&M expenses because of the Public Staff's adjustments. Mr. Teele also stated that if the Company had been accounting for these expenses using the Public Staff's methodology since 1987, the plant investment would be $1 million more than it is today and O&M expenses would have been less.

Public Staff witness Fernald testified in direct testimony that the Company's proposal would increase rate base by an amount that does not show up on the Company's books as plant. In fact, these costs have already been expenses on the Company's books and allowing the Company to include them in plant would result in a double recovery.

Public Staff witness Fernald stated in cross-examination that an accounting entry would not have to be made. This case is to set rates on a prospective basis. In the future the Company will allocate these costs based on payroll distribution, and a portion will be charged to construction and eventually be included in plant. Ms. Fernald stated that the Public Staff was not going back and restating plant.

The Commission agrees that group insurance, injuries and damages, and payroll taxes should follow the payroll distribution and that the plant in service should be increased by an additional $288,095 to recover properly these costs on a going-forward basis. The Company expended the $288,095 to provide service to all of its customers; it follows that if such actual costs in the test year should have been capitalized rather than expensed as the Public Staff proposes and the Company agrees, then such costs should be included in the rate base to give the Company the opportunity to recover such costs, including a fair return, over the useful life of the plant to which they relate.

Based on the foregoing, the Commission concludes that the level of gas plant in service appropriate for use in this proceeding is $186,182,781.

ACCUMULATED DEPRECIATION

The next area of difference between the Company and the Public Staff is accumulated depreciation. The difference of $2,111,688 is composed of the following items:

Item	Amount
Allocation of general plant to non-utility operations	$ 125,079
Capitalization of O&M expenses	13,036
Change in depreciation rates	1,973,573
Total	$2,111,688

Allocation of General Plant to Non-Utility Operations

The first item consists of the Public Staff adjustment to allocate general plant to non-utility operations. As discussed earlier under gas plant in service, the Commission concludes that general plant accounts should be allocated to non-utility operations as recommended by NCNG. The Commission concludes that it is appropriate to also allocate the accumulated depreciation associated with this plant as recommended by NCNG.

Capitalization of O&M Expenses

The second item is related to the Company adjustment to capitalize certain operating expenses. Based on its adjustment to increase plant by these costs, the Company made a matching adjustment to accumulated depreciation of $(13,036). As discussed earlier under gas plant in service, the Commission concludes that these operation and maintenance costs should be included in rate base. Therefore, the Commission concludes that a matching adjustment to accumulated depreciation should be made.

Change in Depreciation Rates

The final item is the change in depreciation rates. In the Evidence and Conclusions for Finding of Fact No. 30, the Commission concluded that the depreciation rates proposed by the Public Staff are reasonable and appropriate for use in this proceeding. Therefore, the Commission accepts the Public Staff's adjustment to accumulated depreciation which reflects the change in depreciation rates as reasonable and appropriate for use in this proceeding.

Based on the foregoing, the Commission concludes that the level of accumulated depreciation for use in this proceeding is $58,864,822.

ACCUMULATED DEFERRED INCOME TAXES

The final area of difference between the Company and the Public Staff is accumulated deferred income taxes (ADIT). The difference of $163,484 is composed of the following items:

Item	Amount
Allocation of general plant to non-utility operations	$ 38,153
Adjustment to reflect actual plant additions	(3,812)
Removal of ADIT related to gain	129,143
Total	$163,484

Allocation of General Plant to Non-Utility Operations

The first item consists of the Public Staff adjustment to allocate general plant to non-utility operations. As discussed earlier under gas plant in service, the Commission concludes that general plant accounts should be allocated to non-utility operations as recommended by NCNG. The Commission concludes that it is appropriate to also allocate the accumulated deferred income taxes associated with this plant as recommended by NCNG.

Adjustment to Reflect Actual Plant Additions

The second item is the adjustment to accumulated deferred income taxes for actual plant additions instead of estimated additions. The Public Staff and the Company agree that accumulated deferred income taxes should be adjusted for plant additions and have used the same methodology to calculate this adjustment. However, the Company's adjustment is based on the estimated additions included in the Public Staff's prefiled testimony while the Public Staff's adjustment is based on the actual plant additions. The Commission concludes that it is appropriate to calculate accumulated deferred income taxes related to additional plant based on actual additions instead of estimated additions.

Removal of ADIT Related to Gain on Sale of Land

The final item is the Public Staff adjustment to remove from rate base accumulated deferred income taxes in the amount of $129,143 related to the gain on sale of land. Public Staff witness Fernald testified that the ADIT related to this gain should be removed from rate base since the Public Staff is recommending that the gain be flowed back to ratepayers.

As discussed elsewhere herein, the Commission concluded that the gain from this sale of land, grossed-up for gross receipts tax, should be recorded in the deferred account to be returned to customers. Therefore, the Commission concludes that the adjustment recommended by the Public Staff to exclude from rate base the ADIT related to this gain is reasonable and appropriate.

Based on the foregoing, the Commission concludes that the level of accumulated deferred income taxes for use in this proceeding is $18,299,972.

SUMMARY CONCLUSION

The Commission concludes that the Company's reasonable rate base used and useful for purposes of this proceeding is $114,712,630, made up of the following components:

Item	Amount
Gas plant in service	$186,182,781
Accumulated depreciation	(58,864,822)
Net gas plant in service	127,317,959
Gas in storage	4,874,675
Materials and supplies	2,006,019
All other working capital items	(1,186,051)
Accumulated deferred income taxes	(18,299,972)
Total original cost rate base	$114,712,630

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

The evidence supporting this finding of fact is found in the testimony of Public Staff witnesses Curtis and Fernald, and Company witness Teele. Both parties recommend end-of-period revenues of $143,002,977, which is comprised of $142,650,447 of sales and transportation revenues, and $352,530 of miscellaneous revenues. No other parties offered conflicting evidence.

Since the position of the Company and Public Staff is reasonable, and no evidence was offered to the contrary, the Commission concludes that end-of-period revenues of $143,002,977, comprised of $142,650,447 of sales and transportation revenues and $352,530 of miscellaneous revenues, is appropriate for use herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52-53

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witness Teele and Public Staff witnesses Fernald and Curtis. In its updated filing, the Company included certain plant additions, such as the Clayton pipeline and the Wilson parallel line, that were completed in September 1991. However, the Company did not recognize any income related to these projects. The Public Staff in its prefiled testimony made an adjustment to impute net income for these plant additions based on the per books ratio of net income to plant for the test year.

Company witness Teele testified in rebuttal that many of the additional volumes will be sold to IST customers, and therefore will result in no incremental margin to the Company due to the IST mechanism.

In supplemental testimony, Public Staff witness Fernald acknowledged that due to the IST mechanism the imputed income in her original testimony may have been overstated. Therefore, she revised her adjustment to include only revenues from residential customers that will be added on the Town of Stantonsburg and Preston Woods Subdivision distribution projects.

However, Ms. Fernald stated that the revenues she reflected on these additions are extremely conservative since no income was reflected for the transmission projects. Ms. Fernald testified that transmission projects will also likely generate additional income for the following reasons:

"(1) Additional volumes will be sold to non-IST customers as a result of these plant additions.
(2) The Company would not spend so much money on system strengthening if it did not expect additional income."

The Company accepted the Public Staff adjustment reflecting additional sales to Stantonsburg and Preston Woods.

As indicated above, the Company and the Public Staff agreed to include only revenues from residential customers that will be added on the Town of Stantonsburg and Preston Woods Subdivision distribution projects. The Commission therefore concludes that it is appropriate to reflect only revenues from residential customers that will be added on the distribution projects that were completed in September 1991.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 54-76

INTRODUCTION

The evidence supporting these findings of fact is contained in the testimony and exhibits of Company witness Teele and Public Staff witnesses Fernald, Henry, and Hoard. The levels of operating revenue deductions proposed by the Company and the Public Staff in their proposed orders are set forth in the schedule below:

Item	Company	Public Staff	Difference
Cost of gas	$100,583,275	$100,333,802	$ (249,473)
Operation and maintenance expenses	16,058,881	15,552,186	(506,695)
Depreciation	7,928,908	5,914,951	(2,013,957)
General taxes	6,499,540	6,496,731	(2,809)
State income taxes	518,728	734,032	215,304
Federal income taxes	1,755,579	2,629,012	873,433
Amortization of ITC	(198,000)	(198,000)	-
Interest on customer deposits	117,045	117,045	-
Interest on excess ADIT	0	(23,957)	(23,957)
Total	$133,263,956	$131,555,802	$(1,708,154)

As can be seen from the above schedule, the Company and the Public Staff agree as to the levels of amortization of Investment Tax Credit (ITC) and interest on customer deposits. The Commission therefore concludes that for this proceeding the appropriate amount of amortization of ITC is ($198,000) and interest on customer deposits is $117,045.

COST OF GAS

The first area of difference between the Company and the Public Staff is cost of gas. In the Evidence and Conclusions for Finding of Fact No. 27, the Commission concluded that the reasonable level for the total cost of gas for use in this proceeding is $100,333,802.

OPERATION AND MAINTENANCE EXPENSES

The second area of difference between the Company and the Public Staff is operation and maintenance expenses. NCNG proposed $16,058,881 for O&M expenses, whereas the Public Staff proposed $15,552,186. The difference of $(506,695) is composed of the following items:

Item	Amount
Allocation of payroll and related expenses to affiliated companies	$ (3,920)
Adjustment to workers' compensation	(49,870)
Customer growth on maintenance expenses	(95,566)
Removal of lobbying expenses	(15,000)
Removal of charitable contributions	(114,736)
Adjustment to rate case expense	(19,244)
Adjustment to company use gas	(14,428)
Residual allocation of property insurance	(7,782)
Residual allocation of industry association expenses	(15,613)
Inflation adjustment	(16,273)
Exclusion of image and competitive advertising	(154,263)
Total	$(506,695)

Allocation of Payroll and Related Expenses to Affiliated Companies

The first item is the Public Staff adjustment to allocate $21,334 of payroll to affiliated companies. Public Staff witness Fernald allocated salaries for certain employees to NCNG Exploration and Cape Fear Energy. NCNG Exploration and Cape Fear Energy are unregulated subsidiaries of NCNG. Ms. Fernald stated that NCNG does not allocate any salaries to NCNG Exploration even though all the work for NCNG Exploration is performed by NCNG employees. NCNG does allocate salaries for certain employees to Cape Fear Energy. Ms. Fernald recommended that 2% of the salaries for employees who work on NCNG Exploration and Cape Fear Energy be allocated to each affiliate. Ms. Fernald also recommended that 2% of the salaries for certain officers be allocated to each of these affiliated companies resulting in a total Company allocation of .18% of the pro-forma payroll costs to affiliates. These recommendations were based on review of the manner in which other gas companies in North Carolina allocate payroll to affiliates and discussions with Company personnel.

On cross-examination, Company witness Teele testified that the Company does not believe that executive salaries should be allocated to affiliated companies. Mr. Teele stated that he and Mr. Wells do not spend a lot of time on affiliated operations and, furthermore, he and Mr. Wells work a lot more than forty hours a week. Mr. Teele stated that the Company would agree to the Public Staff adjustment except for the allocation of the salaries of the three executive officers -- Mr. Wells, Mr. Teele, and Mr. Dew. This results in a total Company allocation of .05% of the pro-forma payroll costs to affiliates.

The Commission concludes that the Public Staff recommendation to allocate 2% of certain salaries, including executive salaries, to affiliated companies is appropriate. As indicated by Mr. Teele in his testimony, executives spend some time on these affiliated companies; therefore, a portion of their salaries should be allocated to these affiliated companies.

If costs related to affiliated companies are not allocated to those companies, and therefore are included in utility rates, ratepayers will subsidize non-utility operations. In order to prevent cross-subsidization, these costs should be allocated to affiliated companies as recommended by Public Staff witness Fernald.

The Commission rejects the Company's argument that this allocation of executive salaries is unnecessary since Mr. Wells and Mr. Teele work more than forty hours a week. If an officer works 100 hours a week and 20 of these hours are spent on operations of affiliated companies, then 20% of the officer's salary should be allocated based on time spent. Whether these executives work 40 hours a week or 100 hours a week, a portion of their salaries should be allocated to affiliated companies.

NCNG and the Public Staff also disagreed on the appropriate level of the group life and health insurance to be included in this proceeding. The Public Staff has proposed a level of $778,029 for this expense. This level of group insurance expense is based on the Public Staff's recommended allocation of payroll to the affiliates. Based on the Commission's finding that the appropriate allocation to affiliates should be .18% of payroll, the Commission finds that the appropriate level of group insurance expense is $778,029, as recommended by the Public Staff.

The final difference between the parties relating to the allocation of payroll and related expenses to affiliated companies relates to the allocation of workers' compensation, excess liability, and accident and health insurance. Having found that the Public Staff's allocation of payroll to affiliates is appropriate for use herein, the Commission concludes that this allocation should be used for insurance as well.

Workers' Compensation

The second item is related to the Public Staff adjustment to workers' compensation other than that noted above. In its update filing, the Company made an adjustment to workers' compensation to reflect an 18.9% increase in base rates that will occur when the Company renews its policy on October 22, 1991. Public Staff witness Fernald accepted the Company's 18.9% increase related to base rates. Ms. Fernald also made an adjustment to reflect a 36% decrease in the workers' compensation premium due to the upcoming change in the experience modification factor.

The experience modification factor is based on each individual company's claim experience for the most current three years. Ms. Fernald stated that

NCNG's three-year claim history for the October 1990 - October 1991 contract year included claims related to the Wilmington accident. When the experience modification is calculated for the October 1991 - October 1992 contract year, the current three-year claim history will no longer include claims related to the Wilmington accident. Ms. Fernald indicated that exclusion of the Wilmington accident claims would reduce the workers' compensation premium by 36%. Therefore, Ms. Fernald adjusted workers' compensation for the 36% decrease related to the experience modification factor as well as the 18.9% increase related to base rates.

In his rebuttal testimony, Company witness Teele stated that the Company would accept part of the Public Staff adjustment for the 36% decrease. Mr. Teele proposed a compromise of 50 percent of the experience modification reduction. Mr. Teele maintained that the Company has workers' compensation because of accidents and no one can predict when an accident will happen. Mr. Teele stated that if the Public Staff adjustment was accepted, he thought the adjustment would give the Company a "low-ball number" for workers' compensation that the Company did not believe is fair.

In cross-examination, Mr. Teele admitted that he thought that the workers' compensation premium will decrease because the time limit on the Wilmington accident claims will run out. Mr. Teele also acknowledged that the Public Staff was not proposing to exclude all workers' compensation premiums, but was merely adjusting for the Wilmington accident.

Mr. Teele admitted that Public Staff Teele Rebuttal Cross-Examination Exhibit Number 3 was a letter from NCNG's insurance agent to the Company indicating that a 36% reduction in the Company's workers' compensation premium related to the experience modification for the Wilmington accident will occur in the upcoming premium year. Mr. Teele also indicated that he had not heard anything to the contrary since this letter was written.

The Commission concludes that it is appropriate to adjust workers' compensation expense for both the known increase in base rates of 18.9% and the known decrease in the experience modification factor of 36%. Both the Public Staff and the Company agree on the 18.9% increase in base rates. As to the 36% decrease in the modification factor, the Company indicated that a decrease will occur and had no evidence contradicting the level of 36% indicated by its carrier.

The Commission agrees with the Company that NCNG has workers' compensation because of accidents. However, as Mr. Teele indicated, no one can predict when accidents will occur. Any adjustments to the current workers' compensation level for possible future accidents would be speculative and inappropriate.

Customer Growth on Maintenance Expenses

The third item is the Company adjustment to reflect customer growth on certain maintenance expense accounts. The Company included $131,510 in O & M expenses for customer growth while the Public Staff recommended $35,944. This difference results from the Public Staff's exclusion of the distribution operations and maintenance expenses. Both parties agreed on the customer growth adjustment to customer accounts expense.

Witness Teele testified that NCNG will incur additional distribution O&M costs relating to the addition of new customers. Witness Teele testified that this occurs because of the additional pipe in the ground and the requirement to send servicemen to perform necessary service work for its customers. In addition, witness Teele noted that NCNG will have a substantial increase in transportation costs because of the additional miles that will be necessary to travel to serve these customers. These distribution O&M expenses are items such as maintenance of mains, services, meters and house regulators, and customers' installation expense. These expenses continue to increase as customers are added and as there is additional pipe to maintain.

Witness Fernald testified that she did not make an adjustment to increase O&M expenses for increased maintenance expenses caused by customer growth because she did not believe such expenses were directly related to customer growth. Witness Fernald subsequently admitted on cross-examination that NCNG could incur additional operation and maintenance expenses to maintain the lines to serve new customers, and she asserted that the Public Staff's adjustment was conservative in that regard.

As an example of the Public Staff's position, witness Fernald admitted that she had added the anticipated additional volumes from new customers in the town of Stantonsburg but made no addition for the expense to serve such customers. Witness Fernald refused to admit that transportation expense in connection with serving the town of Stantonsburg would be directly related to customer growth, even though Stantonsburg is served from Goldsboro, a substantial distance away.

The Commission concludes that it is appropriate to apply customer growth to maintenance expenses as recommended by the Company. These expenses are directly related to customer growth. These costs would grow at the rate of customer growth, and it is therefore appropriate to apply the customer growth rate to these costs.

Lobbying Expenses

The fourth item is related to the Public Staff adjustment to remove lobbying expenses from the cost of service. The Public Staff removed from O&M expenses $27,596 of fees paid by NCNG to Glenn Jernigan and Associates and Tharrington, Smith, and Hargrove for services during the test year. Based on a workpaper prepared by Arthur Anderson, the Company's auditors, the $27,596 expense items consist of the following:

Item	Amount
Glenn Jernigan and Associates	$10,450
Tharrington, Smith, and Hargrove	17,146
Total	$27,596

Company witness Teele testified in rebuttal that $15,000 paid to Mr. Glenn Jernigan should be classified as "legislative liaison work" instead of lobbying. Mr. Teele indicated that Mr. Jernigan, a former State Senator, was on retainer to keep the Company informed of any significant legislation that might affect the gas industry and NCNG. Mr. Teele stated that the Company believes these expenses represent a reasonable and necessary cost of doing business in a regulated environment and should be allowed in cost of service. The Company agreed that fees paid to Tharrington, Smith, and Hargrove for lobbying should be excluded from cost of service.

In cross-examination, Company witness Teele stated that his amount of $15,000 for fees paid to Glenn Jernigan may be incorrect and that he would accept the amount indicated on the workpaper prepared by Arthur Anderson.

Company witness Teele testified that a portion of this "lobbying" expense should be reclassified as recoverable legislative activities work. Mr. Teele testified that because of NCNG's small corporate staff, it has no one in Fayetteville with either legislative experience or the time to travel to Raleigh frequently enough to monitor what is going on in both the legislative and the administrative agencies of government. Witness Teele stated that the amount which was paid to Mr. Glenn Jernigan for providing this service to the Company should be included in the cost of service as it provides a benefit to both customers and stockholders.

The Commission recognizes that NCNG's officers must prepare for various appearances before legislative committees and must address pending legislation affecting natural gas customers. The Commission finds that it is appropriate to include $10,450 for Mr. Jernigan in the cost of service, and that the remaining cost for lobbying expenses should be removed as agreed to by NCNG. The Commission concludes that it is appropriate to include this liaison work due to the greatly increased activity that has affected the LDCs before the legislature and the need for the companies to be aware of the activities that are taking place.

Charitable Contributions

The fifth item is the Public Staff adjustment to exclude charitable contributions of $114,736 from cost of service. Public Staff witness Fernald testified that charitable contributions are not a necessary cost of providing utility service. Additionally, she stated that the ratepayers should not involuntarily be required to pay in rates for contributions selected by the Company instead of the ratepayers.

Company witness Teele testified that charitable contributions are as much an operating expense as any other O&M expenses and should be treated as such for ratemaking purposes. Mr. Teele stated that NCNG tries to be a good corporate citizen in the communities it serves. Mr. Teele also stated that communities depend on the Company to take a leadership role in fund campaigns. Mr. Teele testified that customers do not exercise control over management and business decisions that NCNG makes which ultimately must pass regulatory scrutiny.

The Commission concludes that charitable contributions should not be included in the cost of service for the reasons stated by the Public Staff. It has been a long-standing policy of this Commission to exclude contributions from operating expenses. The Commission finds it appropriate to decrease operating revenue deductions by $114,736 to eliminate charitable contributions from cost of service.

Rate Case Expense

The sixth item is related to the appropriate level of rate case expense to include in this rate case. The Public Staff and the Company agreed on a level of total rate case expenses of $144,333. Following is a breakdown of rate case expenses amount:

Item	Amount
Legal fees	$ 60,000
Depreciation study	32,000
Cost of capital	30,000
Notice to customers	10,997
Out-of-pocket expenses	11,336
Total rate case expenses	$144,333

The Commission concludes that the total rate case expense to be amortized is $144,333.

The difference of $(19,244) in annual rate case expense between the Company and the Public Staff relates to the amortization period to use for rate case expenses. Public Staff witness Fernald amortized rate case expenses over five years instead of the three years used by the Company, based on NCNG's rate case history.

Company witness Teele stated in rebuttal testimony that the three-year amortization period was chosen by the Company because the Company believes that it will be necessary to file another rate case no later than 1994. Significant cost items such as post-employment benefits and environmental costs of manufactured gas plants will likely become rate case issues by that time.

The Commission concludes that rate case expenses should be amortized over three years based on NCNG's anticipated next general rate case filing. Although the time when NCNG will apply for another general rate increase is not known, the Commission is not persuaded that the three-year period anticipated by NCNG is unrealistic or unreasonable.

Based on the foregoing, the appropriate level of rate case expenses for use in this proceeding is $48,111.

Adjustment to Company Use Gas

The seventh item is related to company use gas. In the Evidence and Conclusions for Finding of Fact No. 25, the Commission concluded that the level of company use gas appropriate for use in this proceeding is $374,544.

Residual Allocation of Property Insurance

The eighth item is related to the residual allocation of property insurance to non-utility operations made by the Public Staff. Ms. Fernald testified that since NCNG is involved in several non-utility and affiliated operations, it should allocate common administrative and general expenses to these non-utility and affiliated operations. Ms. Fernald allocated these costs based on the Massachusetts formula, which is a three-factor formula based on property, revenues, and payroll. Ms. Fernald indicated that this formula has been used to allocate common costs in the Public Service and Piedmont rate cases. Property insurance is one of the common administrative and general expenses in Ms. Fernald's residual allocation.

Company witness Teele stated in rebuttal testimony that property insurance is property related and should be allocated based on property instead of the Massachusetts formula.

The Commission concludes that property insurance should be allocated to non-utility operations based on the Massachusetts formula. The Massachusetts formula is a general formula for allocating common costs that are not directly assigned or allocated by the Company on its books. This formula will undoubtedly overallocate some expenses and underallocate other expenses. However, there is no evidence that for common administrative and general expenses as a whole, this formula is inappropriate. The Commission concludes that NCNG's proposal to have a separate allocation factor for one expense that the Massachusetts formula may overallocate, while ignoring expenses where that formula may underallocate, would lead to an unbalanced result and should be rejected.

Residual Allocation of Industry Association Expenses

The ninth item is related to the residual allocation of industry association dues and expenses to non-utility operations made by the Public Staff. As discussed above, Ms. Fernald allocated common administrative and general expenses, including industry association expenses, based on the Massachusetts formula.

Company witness Teele indicated in rebuttal testimony that industry association dues and expenses should not be allocated to non-utility operations since they do not pertain to non-utility operations.

Mr. Teele acknowledged in cross-examination that one advertisement supported by the American Gas Association (AGA) dues is specifically targeted to propane, a non-utility operation, according to the NARUC 1988 Audit Report on the AGA. Mr. Teele also acknowledged that some of the AGA dues support image and competitive advertisements.

The Commission concludes that a portion of industry association dues and convention expenses should be allocated to non-utility operations based on the Massachusetts formula. As acknowledged by Mr. Teele, some of the dues paid to the AGA support activities that pertain to non-utility operations. If costs related to non-utility activities are not allocated to non-utility operations, ratepayers will subsidize these non-utility operations. In order to prevent cross-subsidization, these industry association expenses should be allocated to non-utility operations as recommended by the Public Staff.

Inflation Adjustment

The tenth item is related to the appropriate level of inflation to include in this rate case. The difference of $(16,273) between the Company and the Public Staff relates to the appropriate inflation factor to be used as well as the amounts to which such factor is applied.

The first difference relates to the appropriate inflation factor to be used. The Company advocated a 6.75% inflation factor to reflect inflation through September 30, 1991, based on a 4.5% annual inflation rate. The Public Staff adjusted the inflation factor to 6.375% to reflect inflation through August 31, 1991, based on the 4.5% annual inflation rate proposed by the Company. Ms. Fernald testified that she adjusted for inflation only up to August 31, 1991, since plant and customer growth were reflected through August 31, 1991. Including inflation past August 31, 1991, would not properly match investment, revenues, and expenses according to Ms. Fernald.

The Company has calculated its inflation factor up to the time of the hearing in this docket.

The Commission concludes that it is appropriate to adjust inflation through August 31, 1991, resulting in an inflation factor of 6.375%. Although a portion of plant completed in September is included in rate base, the Company actually recorded this plant on its books as of August 31, 1991. Plant additions that will be recorded on NCNG's books in the month of September 1991 are not included in this rate case. Including inflation only through August 31, 1991, is consistent with the customer growth percentage applied to customer-related expenses by the Public Staff and the Company. Public Staff witness Fernald adjusted customer accounting expenses for customer growth through August 31, 1991. On Teele Rebuttal Exhibit 5, Company witness Teele adjusted customer accounting expenses and certain maintenance expenses for customer growth through August 31, 1991. Inclusion of inflation through August 31, 1991, will be the proper matching of investment, revenues, and expenses.

The other difference between the Public Staff and the Company pertains to the proper amounts to which the inflation factor should be applied. The Public Staff, consistent with its recommendation to exclude lobbying expense and promotional advertising, has excluded these items from the application of the inflation factor as well.

The Commission, having concluded elsewhere herein that it is appropriate to include $10,450 for legislative liaison activities and $51,421 for advertising expenses in the cost of service in this proceeding, finds that it is appropriate to apply the 6.375% inflation factor to these amounts as well.

Based on the foregoing, the appropriate level of inflation for use in this proceeding is $287,867.

Promotional Advertising

The eleventh item is the Public Staff adjustment to exclude $154,263 of advertising expenses. The Public Staff excluded all advertising expense except $5,000 for safety advertisements required by law. Public Staff witness Fernald recommended removing both the $154,263 per book expense and reducing the inflation adjustment by excluding the level of advertising expense from the base.

The advertisements set forth in Teele Rebuttal Cross Exhibit 2 were stipulated as representative of the types of advertisements NCNG has used.

Witness Fernald testified that she excluded expenses relating to what she called "promotional advertising" based on her belief (1) that the advertising promotes the use of natural gas over other sources of energy, such as electricity; and (2) that the advertising stimulates customer growth which will require additional plant and, ultimately, rate increases to recover for such plant. Witness Fernald admitted she excluded all cost for advertisements related to fuel efficiency of natural gas, cost savings to consumers resulting from natural gas use, and advertisements relating to encouraging year-round gas use in energy efficient appliances, like gas ranges and water heaters, as opposed to using gas just for heating.

In support of the Company's advertising, witness Teele testified that most of NCNG's advertisements are designed to encourage off-peak uses of gas for such things as clothes dryers, water heaters and ranges. Witness Teele testified that, if NCNG is successful in its efforts to increase off-peak sales to residential customers and thus improve residentials' load factor, unit cost of service will be lowered, benefitting all customers with energy at more economical prices.

Witness Fernald admitted that changing heat-only gas customers to year-round users of gas should improve the company's load factor and benefit customers. She testified that if residentials had a 100% load factor, there would not be a problem with rate design. Witness Fernald acknowledged that it is not certain people will use gas, and that gas facilities sit idle seven months out of a year for heat-only customers. The Commission believes that witness Fernald did not properly consider the provisions of Commission Rule R12-12 and Rule R12-13(d). N.C.U.C. Rule R12-13(a) provides that no electric or natural gas utility shall be permitted to recover from ratepayers expenditures made for promotional advertising as defined in Rule R12-12 or for other non-utility advertising. NCNG excluded the cost of advertisements dealing with non-utility marketing of appliances. Rule R12-12(c) defines non-recoverable "promotional advertising" as:

> "Any advertising for the purpose of encouraging any person to select or use the service or additional service of any utility or the selection or installation of any appliance or equipment designed to use such utility's service, where such appliance, equipment or service would promote or encourage indiscriminate and wasteful consumption of energy contrary to subsection (d)(5) of this rule." (Emphasis added).

The Public Staff presented no evidence that NCNG's advertising "promoted or encouraged indiscriminate and wasteful consumption of energy contrary to subsection (d)(5)" of Rule R12-12. Instead, the testimony of witness Fernald and witness Teele shows that a portion of the advertising at issue meets the definition of recoverable advertising in R12-12(d)(1) and (5). Subsections R12-12(1) and (5) except from the definition of non-recoverable promotional advertising "(1) advertising which informs electric and natural gas consumers how they can conserve energy or can reduce peak demand for energy. . . (5) advertising which promotes the use of energy efficient appliances, equipment or services." Further, some of the advertising is consistent with Rule R12-13(d), which allows for recovery of expenditures on advertising which is of benefit to the using and consuming public or enhances the ability of the public utility to provide efficient and reliable service.

The Commission has carefully reviewed Teele Rebuttal Cross Exhibit 2, which was stipulated as representative of the Company's advertising. The Commission finds and concludes that approximately two-thirds of such advertising is either designed to compete with other energy sources or to promote the Company's image and should be removed from operating revenue deductions. On the other hand, at least one-third of the content of such advertising is devoted to conservation, reduction of peak demand, and energy efficiency, all of which are permissible under Rules R12-12 and R12-13(d). The Commission concludes that one-third of the per books advertising expense should be allowed in operating revenue deductions for purposes of this proceeding.

DEPRECIATION EXPENSE

The third area of difference between the Company and the Public Staff is depreciation expense. The difference of $(2,013,957) is composed of the following items:

Item	Amount
Allocation of general plant to non-utility operations	$ (27,348)
Capitalization of O&M expenses	(13,036)
Change in depreciation rates	(1,973,573)
Total	$(2,013,957)

Allocation of General Plant to Non-Utility Operations

The first item consists of the Public Staff adjustment to allocate general plant to non-utility operations. In the Evidence and Conclusions for Finding of Fact No. 44, the Commission concluded that general plant accounts should be allocated to non-utility operations as recommended by NCNG. The Commission also concludes that it is not appropriate to allocate to non-utility operations the depreciation expense not associated with this plant.

Capitalization of O&M Expenses

The second item is the Company adjustment to capitalize certain operation and maintenance expenses. Based on its adjustment to increase plant by these costs, the Company made a matching adjustment to depreciation expense of $13,036. In the Evidence and Conclusions for Finding of Fact No. 45, the Commission concluded that these capitalized operation and maintenance costs should be included in rate base. The Commission also concludes that a matching adjustment to depreciation expense should be made.

Change in Depreciation Rates

The final item is the change in depreciation rates. In the Evidence and Conclusions for Finding of Fact No. 30, the Commission concluded that the depreciation rates proposed by the Public Staff are reasonable and appropriate for use in this proceeding. Therefore, the Commission accepts the Public Staff adjustment to reflect the change in depreciation rates as reasonable and appropriate for use in this proceeding.

Based on the foregoing, the Commission concludes that the level of depreciation expense for use in this proceeding is $5,955,335.

GENERAL TAXES

The fourth area of difference between the Company and the Public Staff is general taxes. The difference of $(2,809) is composed of the following items:

Item	Amount
Allocation of payroll taxes to affiliated companies	$(824)
Adjustment to property taxes related to capitalization of O&M expenses	(1,985)
Total	$(2,809)

Payroll Taxes

The first item is the Public Staff adjustment to allocate payroll taxes to affiliated companies. Ms. Fernald testified that payroll taxes should be allocated based on payroll.

As discussed under operation and maintenance expenses, the Commission concludes that the adjustment to allocate salaries to affiliated companies as recommended by the Public Staff is appropriate. Therefore, the Commission concludes that a matching adjustment to allocate payroll taxes to affiliated companies is appropriate.

Property Taxes

The second item relates to the difference between the Company and the Public Staff regarding the capitalization of O&M expenses. Based on its adjustment to increase plant by these costs, the Company also increased property taxes associated with the additional plant resulting from capitalizing these O&M expenses. Having concluded in Evidence and Conclusions for Finding of Fact No. 45 that the capitalization of these O&M expenses is appropriate, the Commission concludes that the Company's adjustment to property taxes is appropriate as well.

STATE INCOME TAXES

The fifth area of difference between the Company and the Public Staff is state income taxes. The $215,304 difference is due to (1) the period used to determine the appropriate surtax percentage and (2) the difference in levels of revenues and expenses used to calculate income taxes.

The first item is the Public Staff adjustment to determine the surtax percentage based on a five-year period instead of the three-year period proposed by the Company. Both the Company and the Public Staff used the amortization period they recommended for rate case expense to determine the appropriate surtax percentage.

As discussed under rate case expense, the Commission concludes that rate case expense should be amortized over three years as recommended by NCNG.

Therefore, the Commission concludes that the representative rate for state income tax surtax is 3% based on an average of the surtax over the upcoming three year period. This results in an overall state income tax rate of 7.9825%.

Based on its findings elsewhere in this order regarding the appropriate level of expenses and revenues, the Commission concludes that the appropriate level of state income tax expense is $720,067.

FEDERAL INCOME TAXES

The difference in federal income taxes of $873,433 between the Company and the Public Staff results from the differences in other cost of service items. Based on the conclusions reached herein, the Commission concludes that the appropriate level of federal income tax expense is $2,544,691.

INTEREST ON EXCESS DEFERRED INCOME TAXES

The final area of difference between the Public Staff and the Company is the Public Staff adjustment for interest on excess deferred income taxes. Ms. Fernald testified that the Commission ordered in Docket No. M-100, Sub 113, that excess deferred income taxes would ultimately be flowed back to ratepayers with interest. Therefore, she made an adjustment to recognize the cumulative interest due ratepayers related to the flowback of excess deferred tax reserves and refunded it to ratepayers over a five-year period. This period was consistent with the amortization period used for rate case expense and the state income tax surtax.

Company witness Teele testified in rebuttal testimony that this adjustment is inappropriate since these excess deferred income taxes were included in NCNG's rate base in the last rate case and in this rate case. Mr. Teele stated that the customers have already received the benefit of excess deferred taxes which the Company is now flowing back and customers should not receive a second benefit of interest. The Commission agrees with witness Teele.

In Docket No. M-100, Sub 113 and Docket No. G-21, Sub 255, dated July 7, 1987, the Commission ordered:

> "That the appropriate amortization of accumulated excess deferred income taxes and unfunded deferred income taxes will be considered either in NCNG's next general rate case or in such other proceeding as the Commission may determine appropriate. Any amounts relating to the adjustment that should have been made by NCNG for the flowback of excess deferred income taxes shall be placed in a deferred account and ultimately be refunded to ratepayers with interest." (Emphasis added.)

The foregoing language contained in the Commission's Order of July 7, 1987, clearly contemplates that the propriety of the treatment to be accorded excess deferred income taxes in all respects was to remain an open question until addressed by the Commission in a subsequent proceeding. The language contained in said Order relating to the payment of interest simply provided for the payment of interest should the Commission ultimately determine that interest was due. For the reasons stated by witness Teele, the Commission finds and concludes that it would be entirely inappropriate and improper to require payment of the interest as proposed by the Public Staff associated with excess deferred income taxes. Therefore, the Commission rejects the Public Staff's proposal in this regard.

SUMMARY CONCLUSION

Based upon the Commission's findings set forth herein, the Commission concludes that the overall level of operating revenue deductions under present rates appropriate for use in this proceeding is $131,704,468, made up of the following components:

Item	Amount
Cost of gas	$100,333,802
Operation and maintenance expenses	15,732,812
Depreciation	5,955,335
General taxes	6,498,716
State income taxes	720,067
Federal income taxes	2,544,691
Amortization of ITC	(198,000)
Interest on customer deposits	117,045
Total operating revenue deductions	$131,704,468

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 77

The evidence for this finding is contained in the testimony and exhibits of Company witness Teele and Public Staff witness Hinton.

The Company, in its original filing, requested that the Commission employ the September 30, 1990, capital structure with adjustments for long-term and short-term debt. This capital structure consisted of 47.16% common equity and 52.84% long-term debt. In updated supplemental testimony, the Company requested that the Commission employ the March 31, 1991, capital structure which then consisted of 49.39% common equity and 50.61% long-term debt. Just as in the original filing, the Company's updated request included two pro forma adjustments: the addition of $25 million more long-term debt and the removal of all short-term debt.

The capital structure recommended by the Public Staff for use in this proceeding is an adjusted June 30, 1991, quarter-ending capital structure consisting of 49.0% common equity and 51.0% long-term debt. The Public Staff, like NCNG, adjusted the long-term debt component of the capital structure to reflect NCNG's planned issuance of an additional $25 million of long-term debt and to exclude short-term debt from the capital structure. The Public Staff's recommended capital structure also reflects elimination of certain Transco refunds from the common equity component of the capital structure.

Both the Public Staff and the Company agreed that the Company's per books capital structure should be used in this case, both agreed that a pro forma adjustment for the planned issuance of $25 million of new long-term debt was appropriate and both agreed that removal of short-term debt in the circumstances of this case was proper. No other party presented evidence on the appropriate capital structure. The Commission therefore concludes that the foregoing pro forma adjustments as proposed by the witnesses are appropriate.

The two areas of difference between the Public Staff and NCNG regarding capital structure are (1) whether to use the quarter-ending capital structure of March 31, 1991, or the more recent capital structure of June 30, 1991, and (2) whether to reduce the equity component of the capital structure by the amount of certain Transco refunds.

With respect to the issue of which point in time to use for the purpose of determining the appropriate capital structure, no party offered any evidence contending that the June 30, 1991, capital structure was inaccurate or unrepresentative. On cross-examination witness Teele indicated that he had updated NCNG's capital structure to March 31, 1991, because it was more appropriate to use more recent data. Witness Teele further testified that March 31 1991, was the most recent data available at the time of his update.

Public Staff witness Hinton testified that the proper capital structure for use in this proceeding should be based on the June 30, 1991, quarter-ending capital structure. Mr. Hinton further testified that his recommended capital structure was composed of significantly more equity than the average capital structure of natural gas companies with capital investments both greater than and less than $100 million.

Based upon the entire evidence of record, the Commission concludes that the June 30, 1991, capital structure, in conjunction with the pro forma adjustments adopted hereinabove, is the most appropriate for use in this proceeding. Such capital structure is reasonable and is based on the most currently available information and data. This capital structure contains an equity ratio that is only slightly less than that proposed by the Company.

With respect to the second issue, the Transco refunds, witness Hinton stated that he reduced the common equity component of the capital structure to remove certain Transco refunds which had been reflected as common equity by the Company. In rebuttal testimony, witness Teele testified that he disagreed with the Public Staff's proposal with respect to the old Transco refunds for the same reasons expressed in NCNG's two prior rate cases. He conceded that the Public Staff's adjustment to remove this amount from the equity component of the capital structure was consistent with the Commission's Order in NCNG's last general rate case.

The Commission takes judicial notice of its Order in the last NCNG rate case, Docket No. G-21, Sub 255, dated November 10, 1986, in which the net-of-tax Transco refunds of $125,377 were deducted from rate base and excluded from the equity component of the Company's capital structure "to prevent ratepayers from paying a return on this cost-free capital." NCNG's position on this issue has been consistently rejected by the Commission in prior rate cases; in this case the Company has stated that it is relying on the same reasons it advanced in such proceedings. The Commission, based upon the entire evidence of record, concludes that the Public Staff's adjustment to remove the Transco refunds from the equity component of the capital structure is consistent with prior Orders, is reasonable and proper and should be adopted for purposes of this case.

Finally, after careful consideration of the entire evidence of record, the Commission finds and concludes that the capital structure appropriate for use herein is as follows:

Item	Ratio
Long-Term Debt	51.0%
Common Equity	49.0%
Total	100.0%

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 78

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Teele and Public Staff witness Hinton.

There is no disagreement concerning the embedded cost of debt to be used in this case. Both the Public Staff and the Company agreed that the embedded cost of debt should be 9.68%.

Therefore, the Commission finds and concludes that the proper embedded cost of long-term debt for purposes of this proceeding is 9.68%. This embedded cost rate includes the effect of the planned issuance of $25 million of long-term debt at a rate of 9.21%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 79

The evidence for this finding of fact is found primarily in the testimony and exhibits of Company witnesses Wells, Teele, and Andrews, and Public Staff witness Hinton.

Company witness Wells testified that the two primary business risks faced by NCNG are (1) the relatively high percentage of gas volumes delivered to customers which have the ability to switch to alternative fuels and (2) the transition to "open access" which has resulted in the risks associated with securing long-term gas supply commitments being shifted from the interstate pipelines to the local distribution companies. Dr. Andrews and witness Teele also testified that these circumstances created business risks for NCNG.

With respect to the first risk cited by witness Wells, Public Staff witness Hinton testified that the Industrial Sales Tracker (IST) reduces the risk of the high percentage of industrial load. He observed that the IST had protected NCNG by allowing the Company to recover a preset total margin from the large industrial customers who have heavy oil as an alternative fuel. Witness Hinton also reviewed the amount of negotiated sales losses from industrial customers who have the capability to switch to alternative fuels like No. 2 oil and propane which are not included in the IST. This review showed the Company had experienced very small negotiated losses from these customers. Mr. Hinton concluded that:

> "In view of the protection inherent in the IST and the relatively small degree of negotiated losses due to other industrial customers having the ability to switch to an alternative fuel, it does not appear that an additional equity risk premium is warranted for the

high percentage of industrial load. Moreover, the equity investors are more concerned with the stability of earnings and dividends which is strengthened in part by the higher industrial load during the summer months."

During cross-examination, witness Hinton emphasized that a high percentage of industrial volumes, rather than creating additional risk, actually has benefits such as a more stable flow of revenues during summer months and a higher load factor. To support this view, witness Hinton further testified that early in his investigation he had compared the quarterly earnings per share (EPS) of the gas companies in his comparable groups and those of Dr. Andrews' comparable group, and it turned out that NCNG and other companies with high industrial loads often had a lower standard deviation of their earnings than the average natural gas local distribution company.

Witness Hinton indicated that the stock market price incorporates and reflects information known to investors, including the risks facing a company. He stated that the DCF model, which he used for estimating the required return on equity, is a market-based approach which incorporates the stock market price; thereby taking into full account information relating to the riskiness of an investment in the common stock of NCNG arising from such factors as those here under review. Clearly, investors have available to them information about NCNG's transition to the open access era and the high percentage of sales to alternate fuel customers.

Witness Hinton was asked to read a portion of the appellate decision on NCNG's last rate case, reported at State ex rel. Utilities Comm. v. Public Staff, 323 N.C. 481 (1988). The part of the North Carolina Supreme Court opinion that he read (323 N.C. at 494) held that the Commission acted within its discretion in considering the risk NCNG faced at that time from the volatility of the gas market and the substantial risk of customers switching to oil or obtaining their own gas, especially for NCNG with its high percentage of industrial sales. In response, witness Hinton pointed out that the decision referred to the volatile environment surrounding the 1986 gas market and that the current market as reported by Value Line was characterized by a more stable gas environment and declining gas prices. Witness Hinton also noted that the risk of loss of profitability as a result of NCNG's customers switching to an alternative fuel is substantially decreased with the IST.

In NCNG's last rate case, the Commission considered both the risk created by having a high percentage of sales to alternate fuel customers at a time of volatile gas markets and "...the fact that the risk of N.C.N.G. has decreased as a result of continued approval of the IST..." The Court also approved the Commission's decision to consider the IST as mitigating risk to the Company.' 323 N.C. at 494. Indeed, in an earlier decision, the North Carolina Supreme Court explicitly recognized that the IST places the risk of lost industrial sales not on NCNG's stockholders but rather on the non-industrial customers who have no alternative fuel:

"Seventy-five percent of industrial customers can negotiate lower gas prices by threatening to switch to alternate fuels. Approximately 35% of the Cities' customers have this fuel switching capacity as well. This ability to negotiate lower rates gives the large industrial and

> commercial customers of NCNG and Cities a bargaining power unavailable to residential and small commercial customers. Such power renders NCNG's large industrial and commercial customers, and indirectly Cities, risky ratepayers because they can force NCNG to meet competitive costs in order not to lose substantial sales. This risk justifies a higher rate of return relative to residential and small commercial customers who ultimately bear the burden of these negotiated prices through the IST."

State ex rel. Utilities Comm. v. Carolina Utility Customers Assoc., 323 N.C. 238, 247-48 (1988). (Footnotes omitted; emphasis added.)

Witness Hinton was also asked by Commissioner Duncan about the makeup of the current NCNG industrial customers relative to a prior period when the gas volumes sold to C.F. Industries constituted 25% of the Company's load. He answered that he did not think there was a customer on NCNG's system that represented that high a percentage of the load. Witness Hinton also stated that NCNG's load is more dispersed now among its customers. Company witness Wells's testimony confirmed that 50 to 75 industrial customers have been added during the past five years, which has helped to reduce the dependency on any single large industrial customer for revenues and earnings.

The Commission concludes that the two major business risks referred to by witness Wells and other Company witnesses do not justify an additional equity risk premium in this case. The Commission notes that the high percentage of alternate fuel customers for NCNG and the transition to open access are circumstances that have existed for years, have been widely discussed in regulatory proceedings, and should be quite familiar to informed investors. Therefore, to the extent that these circumstances create business or financial risk for NCNG, such risk will be reflected in the market price of NCNG's stock. Both Dr. Andrews and witness Hinton used market-based models for estimating the investor-required return on equity for NCNG. Consequently, these models have fully reflected the risks here under review. The Commission has relied upon the market-based evidence presented by witnesses Andrews and Hinton in determining the appropriate cost of common equity. Thus, these risks have been once provided for by the Commission in determining NCNG's cost of common equity capital. Therefore it would be entirely inappropriate to provide for additional equity risk premium by further increasing NCNG's cost of common equity as proposed by the Company witnesses.

Therefore, based on the foregoing and the entire evidence of record, the Commission finds and concludes that the two specific business risks referred to by NCNG witnesses do not justify an additional common equity risk premium, and no such premium will be allowed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 80-83

The evidence for this finding of fact is found primarily in the testimony and exhibits of Company witness Andrews and Public Staff witness Hinton.

In his pre-filed testimony, Dr. Andrews employed three different methods in his cost of equity analysis: the constant growth DCF model, the risk premium method and the capital asset pricing model (CAPM).

In applying the constant growth DCF model to the top quartile of a 16 company comparable group, Dr. Andrews determined the investor return requirement to be 14.48%. In applying the DCF model with a consensus forecast of earnings growth for 10 small LDCs, he arrived at an investor return requirement of 13.37%. Using his risk premium method, Dr. Andrews found 15.40% as the cost of common equity to NCNG. Using his CAPM, Dr. Andrews found 16.14% as the cost of common equity to NCNG. From these results, Dr. Andrews estimated that NCNG's cost of common equity capital lay within a range from 14.0% to 15.0%, and he recommended 14.5% as his point estimate of the cost of common equity.

In Dr. Andrews' supplemental testimony filed on October 8, 1991, he revised his cost of common equity downward. Dr. Andrews cited the decline in the dividend yield of NCNG from 6.57% to 5.68%. Dr. Andrews' final cost of common equity recommendation was a range from 13.5% to 14.5% with 14.0% as his point estimate.

The first approach used by Dr. Andrews was the risk premium method in which the cost of equity equals the yield on riskless debt (the risk-free rate) plus a premium related to the assumption of equity risk (the equity risk premium). For his risk-free rate, Dr. Andrews used the income returns to long-term U.S. Government bonds for the first quarter of 1991, which on an annualized basis is 8.2%. For his equity risk premium, Dr. Andrews used the difference, over a 20 year period, between (1) the equity returns on the smallest quintile by capitalization of stocks traded on the New York Stock Exchange, the American Stock Exchange, and certain over-the-counter stocks, and (2) the income returns to long-term government bonds. This showed a 7.2% equity risk premium. By adding the risk-free rate of 8.2% to the equity differential of 7.2%, Dr. Andrews' risk premium method suggested a 15.4% cost of common equity for NCNG.

Dr. Andrews acknowledged in his prefiled testimony, with respect to the equity differential used as the equity risk premium, that:

> "Studies have found varying differentials. However, we do not have in hand a theory as to the level this differential should assume. Moreover, its historical variations are observable but not readily rationalized."

This problem was illustrated during cross-examination when Dr. Andrews agreed that if equity differentials for his small stocks in Andrews Exhibit 4 are averaged over 10 years, instead of over 20 years, the equity risk premium is 0.73% instead of 7.2%. The resulting cost of equity for NCNG would be 8.93%. An 8.93% cost of equity is obviously too low for NCNG. Yet, as Dr. Andrews confirmed, there is no theoretical rationalization as to why a 20 year average would be correct and a 10 year average incorrect for the risk premium method. The Commission also notes that Dr. Andrews also stated that there was "some consensus" that equity premiums over debt should be in the range of 3% - 6%, yet he used an equity premium of 7.2%.

Dr. Andrews stated that in his risk premium analysis he used stocks that on average are riskier than the market as a whole to develop the risk premium for NCNG, but he also acknowledged that by the beta measure NCNG was less risky than the market as a whole. Dr. Andrews sought to justify this approach on the basis that stock price volatility is greater for small stocks, that NCNG is a small stock and that this indicates greater risk. Yet he also agreed that NCNG is a utility stock and that utility stocks are less risky than the market as a whole. The Commission concludes that, while no single risk measure should be relied on exclusively, the beta measure for NCNG is compelling evidence that NCNG stock is less risky than the market as a whole. Dr. Andrews endorsed the beta as "one of the most widely employed devices in handling common stock returns in many contexts." He also testified that "beta is itself a measure of risk."

Witness Hinton presented two beta measures of systematic or non-diversifiable risk, the reported Standard & Poor (S&P) beta and a beta calculated utilizing the Value Line methodology. Both beta coefficients indicated that NCNG is less risky than the market. Witness Hinton also presented other measures of risk that are unique to NCNG -- meaning that the equity investor can eliminate such risk through portfolio diversification. Such measures of risk are the S&P Financial Ratios, S&P Common Stock Rating, and S&P Price Deviation measure. These measures further support the Commission's conclusion that NCNG stock is not a high risk to the equity investor.

Based upon the foregoing and the entire evidence of record, the Commission finds and concludes that, for purposes of this proceeding, minimal weight should be assigned to Dr. Andrews' risk premium methodology. This decision is based on the weight of the evidence which tends to show (1) that the stock of companies selected by Dr. Andrews' on average are significantly more risky than the common stock of NCNG and (2) that there is little theoretical or empirical support underpining the propriety of Dr. Andrews use of a 20-year period for purposes of determining the equity risk premium in this case.

Dr. Andrews' next model was the CAPM. He referred to it as a form of risk premium analysis. Dr. Andrews explained that in the CAPM the cost of equity for a particular stock "is the sum of the risk-free rate plus the differential of a market-wide rate of equity return over the risk-free rate ... multiplied by the stock's characteristic beta." He also included another term which he characterized as the "alpha term" in his CAPM equation to represent what he described as "imperfection in market valuation of a given equity" or an excessive risk premium. Although Dr. Andrews has waived the use of the alpha term at times in the past, he decided to add this term to his CAPM equation in this case.

In applying the CAPM, Dr. Andrews used five years of data for a group of 16 small LDCs, including NCNG. This resulted in an alpha of 5.66%, which was added to a risk-free rate of 8.57%. This sum was then added to the product of a .3679 beta multiplied times an equity risk differential of 5.19%. The result was a cost of common equity for NCNG of 16.14% based on Dr. Andrews' 16 company composite.

The Commission finds that only minimal weight should be accorded the CAPM result in this case in determining the cost of equity for NCNG. To begin with, Dr. Andrews himself recognized that his application of the CAPM was unreliable because the standard errors of estimate of his betas were high. Dr. Andrews acknowledged that in testimony in another case he had stated that the "CAPM's dominance has yielded to other approaches" and that "difficulties were encountered in application" of the CAPM. The Commission also finds little credibility in the use of the alpha term in Dr. Andrews' CAPM. He indicated that normally if a stock was mispriced so as to result in a positive alpha, the market arbitraged that condition out of existence. Both Dr. Andrews and other investment analysts have applied the CAPM without an alpha for this reason. The Commission rejects the notion that 5.66 percentage points should be added to the average cost of common equity for the composite group of 16 small LDCs to account for market imperfections. Without the alpha term, Dr. Andrews' CAPM would produce a cost of equity of 10.48% (16.14% - 5.66%).

The Commission is further convinced of the inadvisability of relying on CAPM results due to the same flaw as in the traditional risk premium method: the time period over which one calculates an equity risk differential can greatly alter the results for no theoretically explainable reason. There is even inconsistency between Dr. Andrews' methods. He uses a "risk-free" rate of 8.2% for his traditional risk premium analysis and a "risk-free" rate of 8.57% for his CAPM analysis. One is based on first quarter 1991 returns; the other is based on five year income returns. Dr. Andrews has also used ten year income returns in past cases.

As his third approach, Dr. Andrews applied the Discounted Cash Flow (DCF) model in two ways to estimate the cost of common equity for NCNG. In this model, "the cost of equity to a corporate issuer is the sum of a one-year dividend yield on current market price plus the growth rate of dividends." Dr. Andrews developed dividend growth rates for each of the 16 companies in his comparable group, based on five years of data. Out of the 16 comparable companies, Dr. Andrews selected the four companies with the highest cost of equity results, which reflected an average cost of equity of 14.48%.

Dr. Andrews indicated a strong preference for historical information as opposed to analysts' forecasts of the future as a basis for his DCF growth rate term. Nonetheless, he did perform a DCF calculation with a consensus forecast of earnings growth rates for 10 small LDCs. This result showed a 13.37% cost of equity. Dr. Andrews considered both the 13.37% and the 14.48% results in developing his recommendation to the Commission.

Dr. Andrews selected a group of 16 companies, including NCNG, in his DCF model (and his CAPM) because they are all publicly traded, they are all small in size and they are all principally in the local gas distribution business. He testified that these companies were the "best available" in terms of being comparable to NCNG. In contrasting his comparable group to those of witness Hinton, Dr. Andrews stated that it was better to have some similarity in size among the companies even if this meant some dissimilarity in financial attributes. The Commission disagrees. If a group of companies is to be screened for comparability in terms of investor expectations, financial attributes are far more relevant than size. Because the group of 10 companies used in Dr. Andrews' consensus forecast DCF is a subset of the 16-company group, it too fails to show comparability to NCNG.

The fact that Dr. Andrews' "comparable" group is not comparable to NCNG is further revealed in Dr. Andrews' own analysis. In applying the DCF analysis, he disregarded the 12 companies with the lower costs of equity. If all 16 companies were comparable to NCNG, as Dr. Andrews contended, it would be appropriate to use the average cost of equity for all 16. This is shown to be 11.68% on Andrews

Exhibit 10. Dr. Andrews' decision to consider only the top quartile of these companies simply skews his results to a higher cost of capital and contradicts his testimony that the group of 16 is comparable.

Public Staff witness Hinton was the only other cost of equity witness. He employed the constant growth DCF model in his analysis. He performed a DCF analysis not just on NCNG, but also on several groups of comparable companies to smooth out any abnormalities. Witness Hinton explained the use of comparable companies as follows:

> "The cost of equity capital is a cost borne by firms whose equity shares are considered to be risk-comparable investments. In order to estimate the investor required rate of return, I have identified companies in the gas distribution industry that exhibit risk measures similar to NCNG."

Witness Hinton also examined comparable risk companies outside the gas distribution industry as a cross-check. Witness Hinton's first comparable group, Group A, was constructed to include natural gas distribution companies that derive at least 95% of their revenues from gas operations. As shown on Exhibit JRH-3, these companies are also comparable to NCNG in terms of their Value Line betas, their S&P stock ratings, their S&P betas, their price volatility as shown in the standard deviation of stock prices, and their fixed charge coverages. The Group A companies were also chosen for their comparability to each other based on risk measures such as the Value Line Safety Rank, Financial Strength, and Price Stability, and the S&P bond rating, that are not calculated for NCNG.

Witness Hinton's Group B of comparable companies was constructed to include natural gas distribution companies that obtain a larger portion of their revenues outside of the natural gas industry, but are otherwise comparable in terms of the Value Line and S&P measures used for Group A. Similarly, Mr. Hinton's selected his Group C and Group D, which are composed of utility companies and non-utility companies, respectively, because they exhibited comparable levels of risk under the measures used for NCNG and Group A.

To estimate investor expectations for NCNG and the comparable companies, witness Hinton analyzed historical growth rates of earnings, dividends, and book value from two sources. Witness Hinton also presented three sources of forecasted data: Value Line forecasts of earnings, dividends, and book value and five year earnings forecast compiled by Zacks and I/B/E/S.

Based on his DCF analyses, Mr. Hinton concluded that the appropriate ranges for the cost of equity are as follows: (1) Group A-12.3% to 12.7%, (2) Group B-11.5% to 12.7%, (3) Group C-11.5% to 12.3%, and (4) Group D-12.0% to 12.8%. From these ranges, witness Hinton concluded that the cost of common equity to NCNG was within the range of 12.3% to 12.7%. His final recommendation to the Commission was 12.5%.

Dr. Andrews on rebuttal noted that the composition of comparable company groups differed between Mr. Hinton and himself. He maintained that witness Hinton's use of larger companies such as those covered by Value Line was inappropriate. As stated above, witness Hinton screened his comparable companies on the basis of broad risk measures that are published by investment analysts and are widely available to investors. The Commission believes that witness Hinton's approach is a realistic and appropriate way of developing comparable company groups for purposes of estimating the investor-required return and that such approach is clearly superior to the techniques employed by Dr. Andrews.

Dr. Andrews contended that Mr. Hinton had incorrectly calculated the dividend yield term in the DCF equation. He subsequently agreed that he did not know if Mr. Hinton had made an error in the calculation of the dividend yield.

Finally, Dr. Andrews opined that the Value Line dividend growth rate forecasts presented in Hinton Exhibit JRH 5 for Group A should have no application to NCNG because the growth rates are so low for some of the companies. The Commission disagrees. The purpose of examining other companies is to determine a cost of equity for investments of comparable risk, not of comparable growth rates. Witness Hinton's companies are comparable in terms of widely accepted risk measures. Whatever growth rates fall out are appropriate for use in the DCF.

During cross-examination witness Hinton was asked questions regarding the return requirement in view of particular risks to which NCNG investors are exposed. Witness Hinton responded that the common equity cost of known risks is included in his DCF analysis because such risks would be reflected in the market price of the stock. He further testified that the price of NCNG's stock and the risk measures he used would account for NCNG's small asset size and lower number of customers relative to other LDCs. Witness Hinton also testified that such factors would account for the transition to open access, the level of sales to alternate fuel customers and any risk of bankruptcy that might face either NCNG or its customers.

The determination of the appropriate rate of return on equity is one of the most significant decisions which the Commission is required to make in any general rate case. In the final analysis, the determination of a fair rate of return on rate base, including a return on common equity, depends on the informed and impartial judgment of the Commission. Whatever return is allowed must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4) to

> "enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its existing investors."

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> "supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States...."

State ex rel. Utilities Comm. v. Duke Power Co., 285 N.C. 377, 388 (1974).

The Commission is mindful of the fact that its conclusion as to the appropriate rate of return must be based on specific findings that address all material issues raised by the parties. State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 699 (1988).

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 F.2d 547 (1980). State ex rel. Utilities Commission v. Rate Bureau, 300 N.C. 381, 269 F.2d 547 (1980). State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E.2d 786 (1982). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. Utilities Commission v. Power Company, 285 N.C. 377, 395, 206 S.E.2d 269 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." Utilities Commission v. Public Staff, 322 N.C. 689, 694, 370 S.E.2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented (and the weight and credibility thereof) in each case.

The Commission cannot guarantee that NCNG will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if we could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds, and thus concludes, that the rates of return approved herein will afford the Company a reasonable opportunity to earn a reasonable return for its stockholders while providing adequate and economical service to its ratepayers.

There are problems and differences of opinion attending the DCF methodology as well as the risk premium methodologies, including the CAPM. Nonetheless, estimates of the cost of common equity capital based on these methods are entitled to be given weight in reaching our final judgment in this case. We conclude, however, that the DCF methodology presented by the witnesses should be given the greater weight in our determination, particularly the evidence presented by witness Hinton.

In Bluefield Waterworks Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), the Court said (at pages 692-693):

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable,

> sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties. (Emphasis added)

Also, in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), the Court said (at page 603):

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . By that standard the return to the equity owner should be commensurate with return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital. (Emphasis added)

We recognize that G.S. 62-133 has adopted the test set forth in Bluefield as the standard to be used in this case. In State ex rel. Utilities Commission v. Morgan, 278 N.C. 235, 238, 179 S.E.2d 419 (1971), Justice Lake stated that, "In this State the test of a fair rate of return is that laid down by the Supreme Court of the United States in the Bluefield Water Company case. . . ." Therefore, under North Carolina law, it is entirely appropriate to give considerable weight to the cost of common equity derived by witness Hinton as a result of his having performed a DCF analysis with respect to four groupings of companies which he determined to be comparable in risk to NCNG.

The Commission has previously presented herein a summary of the DCF analyses performed by witness Hinton. Witness Hinton's DCF analyses ranged from a low of 11.5% to a high of 12.8%. Based upon the entire evidence of record in this case, the Commission finds and concludes that this range, based on the DCF methodology, more accurately than any other methodology reflects and encompasses NCNG's cost of common equity for purposes of this proceeding. Further, the Commission finds and concludes based upon the entire evidence of record that within this range the appropriate point estimate of the cost of NCNG's common equity is 12.7%. This cost rate is slightly above the point estimate of 12.5% recommended by witness Hinton and reflects the upper bound of the 12.3% to 12.7% range found reasonable by this witness.

Finally, the Commission notes that it has placed no weight on the cost of common equity approved in the recent stipulated rate cases between the Public Staff and Piedmont Natural Gas Company, Inc. (Docket No. G-9, Sub 309) and Public Service Company (Docket No. G-5, Sub 280). The Commission realizes that these cases represent a compromise where both sides met and conducted negotiations that involved tradeoffs on numerous issues by both parties. The stipulations filed in both cases state that the specific adjustments "are reasonable only in the context of the overall settlement between the parties." Indeed, NCNG's witness Andrews shows the cost of equity to Public Service Company of North Carolina to be 11.84% (Andrews Exhibit 11), so the results of the settled cases plainly cannot be considered precedential. The Commission thus concludes that the cost of equity for NCNG should be based solely on the substantive evidence in this proceeding.

Based upon the foregoing, the Commission finds and concludes that NCNG should be allowed in this case the opportunity of earning a return on common equity of 12.7%, which includes no allowance for down markets or flotation costs.

Based upon the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in that capital structure, the Commission further finds and concludes that the overall fair rate of return that NCNG should be allowed an opportunity to earn on its rate base is 11.16%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 84

The Commission has previously discussed its findings and conclusions regarding the fair rate of return which North Carolina Natural Gas Corporation should be afforded an opportunity to earn.

The following schedules summarize the gross revenues and the rate of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. These schedules, illustrating the Company's gross revenue requirement, incorporate the findings and conclusions made by the Commission in this Order.

SCHEDULE I
NORTH CAROLINA NATURAL GAS CORPORATION
DOCKET NO. G-21, SUB 293
STATEMENT OF NET OPERATING INCOME
Twelve Months Ended September 30, 1990

Item	Present Rates	Approved Increase	Approved Rates
Gas operating revenue	$143,002,977	$2,564,512	$145,567,489
Operating revenue deductions:			
Cost of gas	100,333,802		100,333,802
Operation and maintenance expenses	15,732,812	6,946	15,739,758
Depreciation	5,955,335		5,955,335
General taxes	6,498,716	82,428	6,581,144
State income taxes	720,067	197,578	917,645
Federal income taxes	2,544,691	774,370	3,319,061
Amortization of ITC	(198,000)		(198,000)
Interest on customer deposits	117,045		117,045
Total operating revenue deductions	131,704,468	1,061,322	132,765,790
Net operating income for return	$ 11,298,509	$1,503,190	$ 12,801,699

SCHEDULE II
NORTH CAROLINA NATURAL GAS CORPORATION
DOCKET NO. G-21, SUB 293
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended September 30, 1990

Item	Amount
Gas plant in service	$186,182,781
Accumulated depreciation	(58,864,822)
Net gas plant in service	127,317,959
Gas in storage	4,874,675
Materials and supplies	2,006,019
All other working capital items	(1,186,051)
Accumulated deferred income taxes	(18,299,972)
Rate base	$114,712,630
Rates of return:	
Present rates	9.85%
Approved rates	11.16%

SCHEDULE III
NORTH CAROLINA NATURAL GAS CORPORATION
Docket No. G-21, Sub 293
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended September 30, 1990

Item	Capitalization Ratio	Rate Base	Embedded Cost Rate	Net Operating Income
		Present Rates		
Long-term debt	51.00%	$ 58,503,441	9.68%	$ 5,663,133
Common equity	49.00%	56,209,189	10.03%	5,635,376
Total	100.00%	$114,712,630		$11,298,509
		Approved Rates		
Long-term debt	51.00%	$ 58,503,441	9.68%	$ 5,663,133
Common equity	49.00%	56,209,189	12.70%	7,138,566
Total	100.00%	$114,712,630		$12,801,699

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 85 - 91

The evidence for these findings of fact is contained in the direct and supplemental testimony and exhibits of Company witness Teele and the direct testimony and exhibits of Public Staff witness Curtis.

The Company proposed to increase facilities charges for all of its rate schedules as follows:

Description	Present	Proposed
Rate 1 - Heat Only	$ 7.00 (9 months per year)	$ 7.50 (12 months per year)
- All Other Customers	$ 5.00	$ 6.50
Rate 2	$ 9.00	$ 11.00
Rate NGV - Per Vehicle	$ 1.00	$ 1.50
Rate 3A	$100.00	$125.00
All Other Industrial Rate Schedules	$200.00	$250.00

The Public Staff included these same increases in facilities charges in its proposed rate design. As no party opposed the increases in facilities charges shown above, the Commission concludes that the facilities charges for NCNG's rate schedules should be increased as proposed by the Company and Public Staff.

Company witness Teele testified that reconnection fees for residential and commercial customers should be increased as follows:

Description		Present	Proposed
Residential -	September - January	$19.42	$43.69
	February - August	19.42	29.13
Commercial -	September - January	$29.13	$58.25
	February - August	29.13	38.84

As justification, witness Teele pointed to the significant increase in costs required to reconnect customers, particularly during the peak light-up months of September through January. Public Staff witness Curtis proposed that these increases in NCNG's reconnection fees be allowed and as no other party has opposed the increases, the Commission concludes that the reconnection fees should be increased as proposed by the Company and Public Staff.

The Company's returned check fee has remained at $5.00 since the Company's 1983 rate case in Docket No. G-21, Sub 235. The Company proposed to increase its return check fee from $5.00 to $15.00 and, as no party opposed NCNG's increase, the Commission concludes that it is reasonable to increase the returned check fee to $15.00.

Witness Curtis recommended that NCNG implement a connect fee for new residential and commercial customers. Witness Curtis explained that this connect fee, although small, would offset some of the administrative costs of the installation of a new service. Witness Curtis pointed out that electric and telephone companies presently charge new customers a connect fee. Witness Curtis determined his connect fee revenue by multiplying his estimate of new customers added each year (3,200) by his recommended $15 connect fee.

NCNG supported implementation of the connect fee as proposed by Public Staff witness Curtis. No other party objected to the implementation of this connect fee. Since the position of the Public Staff is reasonable, and no evidence was offered to the contrary, the Commission concludes that NCNG should implement a connect fee on new customers of $15. This $15 connect fee should be included in the Company's tariffs and its rules and regulations.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 92 - 106

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Teele, Public Staff witness Curtis, the City of Monroe witnesses Keziah and Crook, ALCOA witness Stickney, and Public Works Commission (PWC) witness Blanchard.

COST-OF-SERVICE STUDIES

NCNG witness Teele prepared a cost-of-service study under existing rates and one based on the Company's proposed rates. These are shown in Teele Exhibit 14, pages 2 and 3.

Witness Teele's prefiled direct testimony indicated that an estimated cost-of-service study was used to allocate revenues, expenses, rate base and taxes. He further testified that while an estimated cost-of-service study provides useful information, a number of other principles and other factors have to be considered.

Witness Teele, in regard to rate of return by customer class, pointed out that, under the Company's cost-of-service study, in order for a customer class to make any contribution at all to net income, that class must yield an overall rate of return of at least 4.94%. According to witness Teele, a return of that size is necessary for the class to cover the cost of debt. The Commission notes that the relationship between risk and return and the existence of variations in levels of risk between rate classes are well established in this and other proceedings. It does not necessarily follow that all customer classes must earn the same rate of return in order to cover debt. It would be inappropriate to install debt coverage as an inviolate floor under class returns, making it superior to all other considerations. However, the Commission acknowledges that coverage of debt may be an appropriate factor to consider, among other factors, in allocating costs.

Public Staff witness Curtis also presented estimated cost-of-service studies. Revised Curtis Exhibit E reflects the summary sheet of a cost-of-service study reflecting the changes in revenues resulting from the Commission's approval of the rate reductions proposed in NCNG's most recent PGA and the correction of the original allocation of revenues. Revised Curtis Exhibit F reflects the summary sheet to witness Curtis' revised cost-of-service study under rates proposed by the Public Staff.

Witness Curtis testified that he reviewed his cost-of-service studies and determined in which direction the rate for each customer class should be moved. He further testified that since cost-of-service studies are subjective and judgmental at best, he did not depend upon them solely. He described his cost-of-service studies as useful as a guide, but like other such studies, they cannot definitively show the returns paid by each class.

Aside from different sales and revenue levels, witness Teele and witness Curtis both testified that the only material difference in the estimated cost-of-service studies prepared by them related to the treatment of distribution mains. More specifically, the difference was identified as how the demand component of the distribution mains is allocated. Witness Teele allocated all of the demand-related component of the distribution mains to the residential and commercial classes. Witness Teele allocated none of the demand-related component of distribution mains to any of the industrial customers. He acknowledged, however, that not all of NCNG's industrial customers are on transmission mains and that some are on distribution mains. Witness Curtis allocated the demand component of distribution mains based on 50% being peak demand and 50% being normal annual sales. This has the effect of allocating some of the demand component of distribution mains to the industrial classes of customers. Because of the creation of a new rate schedule, Rate Schedule 9, for a single customer for which the Company has no investment in distribution mains, witness Curtis' allocation had the effect of allocating some distribution mains to that customer. Witness Curtis conceded that it appears inappropriate under these circumstances to allocate the demand component of distribution mains to the sole customer in Rate Schedule 9. However, witness Curtis maintained that it appears to be even more inappropriate to allocate all of the demand component of distribution mains to the residential and commercial customers and none to the other industrial customers, some of whom are on distribution mains. Witness Curtis suggested that the allocation of distribution mains to Rate Schedule 9 can be corrected by reallocating that small amount of distribution mains to all of the other customer classes.

CUCA's cross-examination centered on the treatment of distribution plant. CUCA favored NCNG's allocation of distribution mains and urged the adoption of equalized rates of return among the customer classes.

Federal Paper Board, the City of Monroe, ALCOA and the PWC also focused on the disparities among the various returns by rate classes and generally urged the Commission to move towards, if not adopt, rates based on equalized returns.

The Commission has consistently maintained and held that it would not be appropriate to design natural gas rates solely on the basis of estimated cost-of-service studies. The Supreme Court of North Carolina has held that factors other than cost of service should be considered in setting utility rates. In State ex rel. Utilities Commission v. N. C. Textile Manufacturers Assoc., 313 N.C. 215, 222, 238 S.E.2d 264, 269 (1985), the Court held:

> "In determining whether rate differences constitute unreasonable discrimination, a number of factors should be considered: '(1) quantity of use, (2) time of use, (3) manner of service, and (4) cost of rendering the two services.' Utilities Comm. v. Oil Co., 302 N.C. 14, 23, 273 S.E.2d 232, 238 (1980). Other factors to be considered include 'competitive conditions, consumption characteristics of the

several classes and the value of service to each class, which is indicated to some extent by the cost of alternate fuels available. Utilities Comm. v. City of Durham, 282 N.C. 308, 314-15, 193 S.E.2d 95, 100 (1972)."

The Supreme Court examined this matter again in State ex rel. Utilities Commission v. Carolina Utility Customers Association, 323 N.C. 238, 372 S.E.2d 692 (1988) (referred to hereinafter as "the Sub 235 remand case"). In that case, CUCA and other parties challenged the Commission's decision in an NCNG general rate case, holding that the differences in rates of return among NCNG's various customer classes were not unreasonably discriminatory nor unjust and unreasonable. The Court found that the Commission had made adequate findings and conclusions and that the Commission had drawn "legitimate distinctions" which justify maintaining large industrial customers' rates of return at a higher level than residential, commercial, and small industrial customers' rates of return. The Court held, "while an assessment of the Commission's Order based simply on the cost-of-service evidence might suggest the adopted rates are unreasonably discriminatory, the Commission's analysis of the non-cost factors permitted in our case law is sufficient to justify the Commission's decision." Id at 252.

The Cities appealed NCNG's next general rate case, Docket No. G-21, Sub 255, on the ground that the Commission had not adequately, through appropriate findings supported by evidence, justified the differences in the rates of return for Cities compared to NCNG's other customer classes. The Supreme Court found that the Commission had supported its conclusions on the discrimination issue with evidentially supported factual findings that it had determined in its administrative expertise do justify the differences in rates of return. State ex rel. Utilities Commission v. Public Staff, 323 N.C. 481, 374 S.E.2d 361 (1988) (referred to hereinafter as "the Sub 255 case").

The Supreme Court examined this matter most recently in State ex rel. Utilities Commission v. Carolina Utility Customers Association, 328 N.C. 37, 399 S.E.2d 98 (1991). In this case, the Court once again held that the Commission did not have to establish rates based solely on cost-of-service considerations.

The Commission reaffirms its previous decisions not to design natural gas rates solely on the basis of estimated cost-of-service studies and rejects NCNG's position that one cost-of-service study should be adopted. Witness Teele conceded on cross-examination that he had previously testified in the Sub 235 remand case that "there are few, if any, hard and fast cookbook recipes that govern the preparation of a fully allocated cost-of-service study." He testified that he agreed with that previous testimony and further testified that while there is a NARUC manual, the real question is how the preparer applies his or her judgment and that honest differences of opinion exist among knowledgeable experts as to how fixed costs should be allocated. Witness Teele filed 18 cost-of-service studies in the Sub 235 remand case, which were based on three methodologies with six different sets of assumptions. A wide range of returns were shown, from 4% to 15% for Rate Schedule 2 and from 152% to negative 4.91% for Rate Schedule 6. Witness Teele further admitted that his conclusion in the Sub 235 remand case was that the historic rate differentials should be maintained, with the residential class paying the highest rate, but no further increase was needed simply on the basis of some estimated cost-of-service study that contained allocations of cost that were at best arbitrary and at their worst could be considered unfair.

The Commission agrees with witness Teele's previously stated opinion as to the value of estimated cost-of-service studies. The preparation of a fully allocated cost-of-service study involves cost classifications and then allocations of every item on the Company's books. Witness Curtis used 43 different allocation factors, while witness Teele used 51. While the area of material difference between NCNG and the Public Staff in this particular case seems relatively narrow, the difference in the allocation of the demand-related component of the distribution mains is one of the most controversial parts of the allocation process. With regard to the allocation of the demand component of distribution mains, unless rate schedules are developed that group customers by location and by whether or not the customer paid for the extension of service, precise allocations are impossible. It is for these reasons that the Commission rejects the argument that it should adopt the Company's estimated cost-of-service study and use it as the major factor in setting rates. The ultimate adoption of one estimated cost-of-service study would lead to a proliferation of proposed cost-of-service studies and lengthy cross-examination into each of the individual cost allocation factors. The Company conceded in response to cross-examination that as transportation and negotiations increase, as they have since 1985 when the Sub 235 case was heard on remand, cost-of-service studies become less important and value of service becomes more important.

The Commission notes that in the recent Order Granting Partial Rate Increase in Public Service Company of North Carolina, Inc.'s, general rate case in Docket No. G-5, Sub 280, dated November 1, 1991, it specifically found it was not reasonable to adopt the goal of solely cost-based rates.

Because estimated cost-of-service studies are subjective and judgmental, it would not be reasonable to adopt one cost-of-service study and use it as the major factor in setting rates.

RATE DESIGN

The evidence concerning rate design is found in the testimony and exhibits of NCNG witness Teele, Public Staff witness Curtis, the City of Monroe witnesses Keziah and Crook, ALCOA witness Stickney, and PWC witness Blanchard.

As the factors he considered in addition to the estimated cost of service, NCNG witness Teele listed the following: (1) value of service and competitive conditions, measured principally by prices of alternative fuels and other economic factors existing in the marketplace including the ability to negotiate rates; (2) usage characteristics; (3) historical rate structure and the relationship between the rates; (4) national and state policies; (5) changes in the industry; (6) the equipment and other facilities which the Company must provide and maintain in order to the meet the requirements of its customers; (7) the need for energy conservation, but also the need to develop more off-peak usage for certain classes of customers; and (8) the ease of administration of the rates established.

Witness Teele described the factors he listed as being considered to some extent in an estimated cost-of-service study, but generally incapable of precise quantification. He further testified that the person establishing the actual rates to be charged must use his or her expert judgment and weigh these additional factors along with the results of the estimated cost-of-service studies. He described the consequences that would result from setting industrial rates solely on the basis of estimated cost of service. He urged the Commission, however, to adopt his estimated cost-of-service study and to use it to a larger degree than in the past.

Witness Teele further testified that he gave his estimated cost-of-service studies and the prices of alternate fuels the greatest weight.

Witness Curtis testified that he considered a number of factors in addition to cost of service for rate design purposes, including (1) the value of service to the customer; (2) the type and priority of service received by the customer, and if the service is interruptible, the frequency of interruptions; (3) the alternate fuel capabilities of the various customer classes; (4) the historic rate differentials among the various classes of customers; (5) the quantity of use; (6) the manner of use; (7) the time of use; (8) the competitive conditions in the market place related to the acquisition of new customers; (9) the encouragement of growth; and (10) the revenue stability of the utility.

With regard to whether rate design should equalize the returns shown in estimated cost-of-service studies, witness Curtis pointed out that the Commission consistently has rejected proposals for equalized class returns, including such a proposal in NCNG's last rate case. He further testified as to the reasons why the Commission should not set equalized class returns as a goal in this case. First, any attempt to equalize returns requires that the Commission rely on a single cost-of-service study. Since such studies are subjective and judgmental, the Commission should continue to adhere to its past practice of not relying on any single study. Second, equalized returns imply that the cost of serving varying customer classes can be compared fairly in a cost study. This is not the case because large customers have alternate fuels and can negotiate, leaving the smaller customers to make up any negotiations losses through the IST. Third, alternate fuel customers should be charged on a "value of service" basis, because they can choose between gas and oil or propane depending upon which fuel offers greater value. The fourth, and last, reason was that the high-priority customers already pay a much higher rate per unit of gas. They have consistently shouldered the greater part of rate increases, particularly in NCNG's last rate case. It would be inequitable to again substantially increase their rates, while continuing to substantially decrease the rates for large commercial and industrial customers.

CUCA argued that the appropriate use of alternate fuel prices in designing natural gas rates is as a "ceiling" above which otherwise cost-based natural gas rates should not be allowed to rise. CUCA pointed to the extensive alternate fuel price information contained in the record of this proceeding and maintained that the rates proposed by both the Company and the Public Staff for residential and small commercial customers are below the prices of available alternate fuels while the industrial rates proposed by both NCNG and the Public Staff are within the range of alternate fuel prices reflected in the record. CUCA asked the Commission to raise NCNG's residential and small commercial rates while lowering its industrial rates. NCNG responded by pointing out the greater financial risk posed to the Company by fuel-switchable industrial customers. The Company stressed the importance of being able to negotiate gas prices below the tariff rate when alternate fuel prices are low, in order to lessen the risk of losing customers. However, NCNG stated that it was equally important that the tariff rate be set so as to result in a return being paid by these customers when alternate fuel prices are high that will compensate the Company for the higher risk of serving these customers. The Commission finds the Company's arguments compelling. Value of service pricing is not a one-way gate, as CUCA would like it to be. It cannot be invoked by industrial customers when alternate fuel prices relative to gas prices fall, only to be abandoned in favor of strict cost-of-service pricing when the prices of alternate fuels relative to gas rise. The higher risks posed in serving customers who can easily switch require adequate compensation. The Commission therefore concludes that alternate fuel prices should not act as a cap on natural gas rates.

The City of Monroe witness Keziah testified about the benefits to the citizens of Monroe resulting from the provision of natural gas service by the City and asked the Commission to consider the impacts on the City's ability to compete with NCNG and other municipalities for new and relocating businesses and to provide service to its customers at reasonable rates. He further requested that the Commission support, or at least not prevent, the City's efforts to seek out and secure more economic gas-supplier arrangements. Witness Crook testified about the City's concerns with respect to NCNG's proposed service agreement and ten-year contract term.

ALCOA witness Stickney urged the Commission to approve rates that yielded returns that more closely approximated the overall approved return.

PWC witness Blanchard testified regarding the need to go further than NCNG proposes in equalizing class rates of return in order to recognize the role of the PWC as a gas customer of NCNG and to be fair to the electric customers of the PWC for whom all the natural gas purchased from NCNG is used.

With respect to NCNG's contention that the North Carolina Supreme Court issued a mandate in its earlier decisions that the Commission equalize the class rates of return, the Commission finds that there is no language in the Supreme Court's opinion in the Sub 235 remand case or in the Sub 255 case that constitutes such a mandate. The only language referring to moving in the direction of more nearly equalizing the rates of return appears near the end of the Sub 235 remand opinion. After writing eight pages as to why rates should not be based solely on cost-of-service studies and how the Commission's conclusions with respect to non-cost factors were supported by the evidence, the Court noted as particularly significant that the rate design adopted by the Commission had not resulted in any increase in the rates of the Cities, while the rates of NCNG's residential, commercial and small industrial classes had been increased. The Court then noted that "the approved rates at least move in the direction of more nearly equalizing the rates of return among all NCNG's customer classes." Id. at 251. This language follows a detailed discussion and a holding that "[i]n analyzing and distinguishing the application of these [non-cost] factors to the opposing customer classes, the Commission drew legitimate distinctions which justify its decision to maintain industrial and Cities' rates of return at a higher level than residential and commercial and small industrial rates." Id. at 250-51. Surely a mandate such as NCNG contends was made would have been expressed more clearly and with more force.

In the Sub 255 case, the Court held the approved rates to be reasonable and merely noted that the approved rates moved the residential return to a positive one. This could be interpreted at best as an indication that rates yielding negative returns might or might not pass appellate scrutiny. Although negative returns had been involved in the two previous NCNG rate cases, they are not an issue in this case.

The law is well-established that factors other than estimated cost of service should be considered in setting utility rates. The Supreme Court has listed, discussed and approved the Commission's use of the factors set forth in witness Teele's and witness Curtis' testimony in a number of cases over the last decade, as previously discussed. Designing rates to equalize class rates of return would require the Commission to virtually ignore all of these other factors. The Commission rejects such an interpretation of the Supreme Court's opinions and again concludes that class rates of return should not be equalized and that the factors previously approved by the Court must be considered when rates are designed.

With regard to equalized rates of return, it has been well-established in prior cases and by testimony in this record, that return is a function of risk and that different customer classes present different risk profiles. Further, the rates of return among customer classes, as shown on estimated cost-of-service studies, are not directly comparable. The rates of return for customers who have no alternate fuels readily available, such as residential customers, should not be compared directly to the rates of return for those customers who do in fact have alternate fuels that can be switched to in a matter of minutes, such as many the industrial customers. Rates of return for customers who cannot negotiate their rates with the Company should not be directly compared to rates of return for those customers who can and do in fact negotiate. The services provided are not directly comparable. Thus the establishment of rates in this proceeding based solely upon an adopted cost-of-service study with the resulting equalized rates of return for all rate classes clearly would be unjust, unreasonable and inconsistent with the evidence.

The Commission recognizes that the residential and certain industrial and commercial customers do not generally have the ability to switch rapidly to an alternate fuel, nor are they able to negotiate their rates. The risk to NCNG of maintaining its margin on service to these customers is significantly less than the risk to the Company of maintaining its margins on service to large industrial customers who can negotiate, absent an IST. Furthermore, the use of an IST places the additional risks and costs on the residential and other customers who cannot negotiate and requires them to participate in the maintenance of margins on service to large industrial customers. In addition, because the impact of losing one large industrial or commercial customer far exceeds the impact of losing one residential or small commercial customer, the large customers create a greater risk. All of these increased risks of serving the industrial customers justify a higher rate of return for the rate schedules under which they receive service.

Turning now to the question of the magnitude of the increase NCNG is proposing for the residential class, the Commission notes that because of the allocation of the vast majority of NCNG's investment between its 1986 rate case (the Sub 255 case) and this case to the residential and commercial classes, the returns these classes are shown to be paying by both witness Teele's and witness Curtis' estimated cost-of-service studies under existing rates are significantly lower than the returns under proposed rates in the last rate case. Substantially all of the increase in the Sub 255 case was placed on the residential and commercial classes, causing residential rates to go up 16%. This non-gas related increase in rates has not been changed since NCNG's last rate case, yet the return both estimated cost-of-service studies show the residential class to be paying has dropped. Under this scenario, the only way to move the returns as shown by estimated cost-of-service studies closer to the average return in the absolute sense would be to place increases on the residential class of the magnitude of the 34% increase in non-gas costs recommended by witness Teele. This proposed increase is cushioned right now by the decreases in the cost of gas that were approved effective October 1, 1991, in NCNG's most recent PGA proceeding. The Company has testified, however, that the gas surplus bubble is expected to burst soon with the result that gas prices will be going up over the next few years. If NCNG's gas costs go up, those increase will be passed on to NCNG's customers through a PGA proceeding, which will not affect the 34% non-gas cost increase in residential rates being requested in this case.

The Commission is concerned that an increase of the magnitude requested by the Company for service to its captive customers, even though currently offset in part by gas costs reductions, might cause substantial hardships to these customers. These customers already pay the highest per unit price of gas on NCNG's system. The uncontradicted evidence shows that gas costs have decreased 25% from 1983 through 1990. During the same time period, the rates of the industrial classes of customers have decreased 31%, while the rates of the residential class have decreased only 4%. Because the rates of the residential class of customers have not decreased in the same proportion as the cost of gas has decreased, the residential class has been paying a steadily increasing percentage of NCNG's non-gas costs. The evidence also shows that the recently approved residential rates of Piedmont and Public Service are lower than those proposed by NCNG.

The Commission has historically concluded (and been upheld by the North Carolina Supreme Court) that specific customer classes should not receive rate increases which, in light of all the surrounding facts and circumstances, result in "rate shock." In determining whether a specific class increase results in "rate shock," the Commission considers the utility's historic rate design, as well as other relevant facts and circumstances. Placing a 34% rate increase on the residential class as proposed by the Company would place an unreasonable burden on that class relative to their historical rates. The rate design approved by the Commission will not result in "rate shock" to any class of customers served by NCNG.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 107 - 130

NEW RATE SCHEDULES

The evidence for these findings of fact and conclusions is contained in the direct and supplemental testimony and exhibits of Company witnesses Wells and Teele and in the testimony of City of Monroe witnesses Keziah and Crook.

The Company proposed to establish the following new rate schedules to reflect two-part, demand/commodity rates for certain large firm service customers:

Description	Sales Rate Schedule	Companion Transportation Rate Schedule	Contract Demand (Dt/Day)
General Service to Municipalities and Public Authorities	RE-2	T-6	41,000
Service to Large Float Glass Furnaces (Priority 5)	9	T-5	9,500
Military Bases with Contract Demand >3,000 Dt/Day	10	T-10	5,200

Rates proposed by the Company and the Public Staff for municipal natural gas distribution systems, for large float glass furnaces and certain military bases under the new rate schedules shown above include a contract demand charge and a commodity charge. According to Company witness Teele, the dramatic changes experienced in the natural gas industry following the enactment of the Natural Gas Policy Act of 1978 and the development of "open access" interstate pipelines have resulted in significant alterations in the cost of purchasing and obtaining the delivery of natural gas for resale. These changes have effectively raised the cost of providing gas service to firm customers and reduced the cost of providing gas services to interruptible customers as a result of increasing fixed gas costs and declining commodity costs. With increasing fixed gas costs, rates with separately stated demand charges more accurately reflect the cost of providing firm service than pure commodity rates.

The Company's proposal for Rate Schedules RE-2, 9 and 10 is to provide firm service up to the respective level of contract demand. Customers on these rate schedules are not entitled to firm service beyond the level of their individual contract demands. If such customers overrun their daily contract demands, they would pay NCNG for the incremental volumes at a 100% load factor rate if NCNG is not curtailing service to its other customers. In the event NCNG is curtailing service to its non-firm customers, then any daily overruns over the individual contract demand levels that would otherwise be subject to curtailment would be subject to charges at emergency gas rates. Also, in the event of force majeure conditions, the customers served under these two-part rates would be subject to interruption on the same basis as the Company's interruptible customers under the provisions of Commission Rule R6-19.2.

Customers served under Rate Schedules RE-2, 9 and 10 have the option of receiving firm sales service from the Company or they may purchase their own gas supplies and transport the gas on NCNG's system. However, the Company is never required to transport gas on a firm basis unless its customers have arranged for transportation on the interstate pipeline system of either Transco or Columbia. NCNG proposed in this proceeding to assign firm transportation capacity on Transco to any of the customers on Rate Schedules RE-2, 9 and 10 subject to availability of capacity assignment programs authorized by FERC. Such capacity assignment programs would also be subject to the approval of this Commission and on terms that are commercially acceptable to NCNG and which do not shift costs to other customer classes or result in the loss of needed capacity to serve NCNG's core market residential and commercial customers on peak days or otherwise during emergency conditions. The Commission notes that, at the time of the hearings, no such FERC approved capacity assignment program existed. Any terms and conditions which might be attached by the FERC or the various parties are unknown. The Commission concludes that it would be premature for the Commission to authorize a capacity assignment program in this proceeding. NCNG's proposed tariffs should be modified to reflect this change.

RATE SCHEDULES RE-2 AND T-6

Many factors have to be taken into account in setting the rates for NCNG's municipal customers. The Cities generally serve a mix of customers similar to that served by NCNG. They are in many respects unique. NCNG witness Teele testified that the Cities do not operate at as good a load factor as NCNG's industrial customers. The Cities have industrial customers with alternate fuels who must be negotiated with if the prices of alternate fuels fall below that of natural gas. Likewise, the increased risk associated with serving a substantial industrial market indirectly through the Cities under Rate Schedules RE-2 and SM-1 favors a higher rate of return for these rate schedules. The Cities also contribute greatly to NCNG's peak load. The municipal rate schedule is intended to reflect an approximate composite of the priorities of service (mix of customers) represented by the Cities. An estimated cost-of-service study does not capture many of these factors. NCNG is proposing to change the municipal sales rate from RE-1 to RE-2. The difference is that RE-2 is a two-part rate with a demand charge of $8.50 per dekatherm of daily demand and a lower commodity rate for the municipal customers. This schedule would provide firm service up to the level of contract demand, except for limited interruptions.

Company witness Teele testified that two of the four municipal customers expressed an interest in a demand/commodity rate. He also testified to the need to establish demand charges for customers that require firm service. Witness Teele testified that it was necessary to go to a two-part rate because of the higher level of pipeline and producer fixed charges. Since the imposition of a demand charge results in a lower commodity rate, the Cities should be better able to market their gas and have an incentive to improve their load factors.

Public Staff witness Curtis testified that the imposition of a demand charge reduced the risk the Company incurred in serving a customer that did not have a demand charge before and that he took that into account in the final rate design he proposed.

The City of Monroe was the only party to offer testimony in opposition to the establishment of Rate Schedule RE-2. City witness Keziah testified that NCNG's proposed rates would result in increased rates to all customers on Monroes's system. Witness Keziah asked the Commission to evaluate NCNG's proposals in light of the City's ability to compete with NCNG and other municipalities for new and relocating businesses. Witness Keziah further requested that the Commission support or at least not prevent the City's efforts to seek out and secure more economic gas supplier arrangements.

City witness Crook testified that the RE-2 rate class was being asked to assist the Company by signing a commitment for a firm supply of gas and that there should be some benefit reflected in rates for sheltering the Company from some risk. He termed the proposed increase in rates excessive and added that the terms and conditions of service in the proposed RE-2 rate schedule were burdensome and unreasonable. In addition to the Company's proposed rates, witness Crook objected to the sole provider provisions, the inability of the RE-2 customer to reduce contract volumes, possible difficulty in increasing the customer's contract volumes and curtailment provisions. Witness Crook furthermore objected to the ten-year term of NCNG's proposed service agreement and cited the potential for changes in the Company's rates as a factor making a ten-year commitment very risky. Witness Crook testified on cross examination that if Monroe lost a major customer, the City would not be able to reduce its contract demand. The City would like the option to resell its capacity on NCNG if its own sale volumes fall. He acknowledged that, while Monroe's contract demand with NCNG has been 4,500 Dts per day since 1970, NCNG has sold Monroe approximately 9,600 Dts on Monroe's peak day in the past year. He also acknowledged that NCNG has looped a line in Union County that benefitted Monroe.

Company witness Wells testified that the Company could not afford to sign long-term contracts for firm gas for the City of Monroe without a long-term commitment from the City. Witness Wells testified that the 8,000 Dts per day contract level proposed to Monroe was the Company's estimate of the minimum needed by Monroe on a "designed winter base" when all of the City's interruptible load is off. He added that 9,592 Dts was the largest daily volume taken by the City in 1991. He recommended that, in the event that an RE-2 customer cannot come to terms with the Company on a contract demand level, the level, pending negotiation of a contract, should be set on the customer's highest peak day volume during the last five years. Witness Wells agreed with Monroe that the level covered by the demand charge should not be subject to curtailment except in the event of a force majeure situation. Witness Wells testified that the long-term contracts that NCNG must sign to meet Monroe's needs are also subject to the same vagaries that witness Crook was concerned with. He also pointed out that the proposed RE-2 demand charge was considerably lower than the demand charge paid by NCNG under its contract with Transco.

The Company agreed to modify its Rules and Regulations to limit the curtailment of customers paying demand charges below contract demand levels to force majeure situations. It also agreed that the sale of gas above contract demand levels would be at a 100% load factor rate as long as NCNG was not curtailing its other customers, and that sales would be charged under Rate Schedule E-1 only in the event that curtailment was in effect. Two of the four municipal customers have requested a demand/commodity rate. Increased payments of demand charges to pipelines and producers make the inclusion of a demand charge in municipal rates appropriate. It would not be appropriate to require the Company to enter into long-term agreements with producers and pipelines to serve municipal customers without some commitment from the municipal customers. Pending the outcome of Monroe's negotiations with NCNG, the Commission wishes to treat Monroe fairly in relation to the other municipal customers. The establishment of a two-part rate necessitates the establishment of a maximum daily quantity to which the demand charge can be applied. Monroe's proposal that the interim demand level be set on a monthly basis is unreasonable. The Company proposed to set the interim demand charge on the City's highest daily take in the last five years, with an annual upward rachet. The Company argued that demand charges are necessary to help cover the fixed costs paid to producers and pipelines. These fixed costs secure capacity to meet demand on the Company's peak day. It was also noted that municipalities are a unique mix of residential, commercial and industrial customers. The record shows that Monroe's highest volume of gas taken on a single day in the last four years included some industrial load. Company witness Wells testified that the 8,000 Dts per day contract demand proposed for Monroe by the Company represented the Company's estimate of Monroe's demand without interruptible load. For these reasons, the Commission finds that an RE-2 customer's demand level, prior to the signing of a contract, shall be set at the customer's highest volume of gas taken on NCNG's peak day over the five previous years. Demand charges are intended to reserve capacity on NCNG's system on the Company's peak day. The Commission concludes that it is more appropriate to base the customer's interim demand level on the volume of gas taken by the customer on the Company's peak day, rather than the greatest volume taken by a customer on any day, since the customer's highest day may be a day on which interruptible loads are being served.

The Commission concludes that the establishment of Rate Schedule RE-2 in place of RE-1, and with corresponding transportation rate T-6, is reasonable and appropriate, subject to modification of rates as otherwise provided in this Order.

The Commission declines to act on Monroe's request to "offer guidance" in its negotiations with NCNG. In the event that the parties cannot come to terms, a complaint proceeding could be initiated before the Commission.

RATE SCHEDULES 9 AND T-5

NCNG has proposed to establish a two-part Rate Schedule 9 and transportation rate T-5 with a $7.00 per DT demand charge to serve Large Float Glass Furnaces. Libby-Owens-Ford Company (L-O-F) is the only customer in the proposed rate class. L-O-F is the largest consumer of natural gas in the State of North Carolina. L-O-F operates at a very high load factor of 95% to 100%. In May 1990, L-O-F entered into a 15-year contract with the Company for firm service. The agreement between NCNG and L-O-F provides for interruption of natural gas service in the event of "force majeure, the demands of the Company's residential, commercial and other higher priority customers under the Commission's approved curtailment plan, other conditions beyond the control of the Company or Customer, lack of sufficient delivery capacity, and when provided by the Rules and Regulations of the North Carolina Utilities Commission." Company witness Teele testified that the rates proposed by the Company were in accordance with the 15-year contract signed by the Company and L-O-F. Witness Teele stated that the commodity sales rates and resulting transportation rates proposed by Public Staff witness Curtis for Rate 9 and Rate T-5 are higher than the rates proposed by the Company. Witness Teele further testified that the transportation rate proposed by the Public Staff would violate the contract signed by the customer in May 1990. He acknowledged that the Commission is free to increase or decrease the rates charged to L-O-F, but stated that the Company preferred that the agreed-to rates be maintained. He pointed out that under the cost-of-service studies of both the Company and the Public Staff, L-O-F provided an above-average rate of return (18.02% according to the Company's estimated cost-of-service study and 50.03% according to the Public Staff's estimated cost-of-service study). On cross-examination, witness Teele acknowledged that the contract had not been submitted to the Commission for approval.

As was noted in the earlier discussion of cost of service, Public Staff witness Curtis acknowledged that the Public Staff's cost-of-service study had allocated distribution mains to Rate Schedule 9, even though NCNG has no investment in distribution mains to serve L-O-F. Witness Curtis recommended that the distribution mains allocated to Rate Schedule 9 in his cost-of-service study be reallocated to all other customer classes.

In considering Rate Schedule 9, the Commission retains its right to set rates, free of constraints imposed by any contract between the utility and its customer. State ex rel. Utilities Commission v. VEPCO, 285 N.C. 398, 206 S.E.2d 283 (1974). The proposed contract rates are but one of many factors considered by the Commission in this proceeding. The Public Staff did not present convincing justification to support adoption of its proposed rates for this Rate Schedule. Therefore, the Commission concludes that the establishment of Rate Schedules 9 and T-5 as filed is reasonable and appropriate for purposes of this proceeding for the reasons stated by NCNG in its testimony.

RATE SCHEDULES 10 AND T-10

The Company's proposal to establish two-part Rate Schedules 10 and T-10 with a $7.00 per Dt demand charge for Service to Military Bases with Contract Demand Greater Than 3,000 Dt per day grew out of discussions with authorities at Fort Bragg. Under NCNG's existing rate structure, the Fort Bragg military base has been served under Rate Schedule 1 for residential use in barracks' and Rate Schedule 6 for boiler fuel requirements. Prior to this proceeding, the authorities at Fort Bragg requested NCNG to consolidate their service into one rate schedule in a manner similar to the existing schedules for municipal gas distribution systems. The Company's proposed establishment of Rate Schedules 10 and T-10 recognizes the unique characteristics of serving a large military base. The establishment of Rate Schedules 10 and T-10 was not opposed by any party. The Commission concludes that the establishment of Rate Schedules 10 and T-10 is reasonable and appropriate subject to modification of rates as otherwise provided in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 131 - 137

Public Works Commission (PWC) witness Blanchard suggested that the Commission establish a new rate schedule for customers using natural gas for the purpose of generating electricity. He testified that the rate of return provided by PWC should be lower than proposed by the Company. According to witness Blanchard, gas sold to PWC constitutes about one-half of the test year volumes taken under Rate Schedules 6 and T-1. In view of PWC's size, witness Blanchard testified that the establishment of a separate rate schedule for electric generation customers would be reasonable and appropriate. He testified that approximately 50% of PWC's electric load went to serve residential customers and therefore PWC's residential electric customers were subsidizing NCNG's residential and commercial gas customers. However, Mr Blanchard did not suggest a proposed rate for electric generation customers or describe the manner in which such a rate might be developed. Under cross-examination, witness Blanchard conceded that gas sold at negotiated rates was totaled under Rate Schedule S-1, so PWC's share of test year volumes in Rate Schedules 6, T-1, and S-1 was about 30%. He stated that PWC does perform cost-of-service studies and that PWC's residential customers provide a 7% to 8% rate of return compared to a 16% return from commercial customers. Furthermore, he conceded that all of PWC's electric customers received the same firm service with no provisions for negotiation or transportation. Witness Blanchard also testified on cross- examination that PWC transfers some money to the City of Fayetteville and finances its expansion using municipal bonds. He stated that PWC's alternate fuel is #2 fuel oil and that gas is currently cheaper. Other than witness Blanchard's request for a lower rate of return, PWC did not propose specific rates, terms, or conditions for its proposed electric generation rate class. In the absence of more detailed information concerning the cost of serving PWC, the Commission cannot conclude that it should establish an electric generation rate in this proceeding. Company witness Teele testified that NCNG was willing to develop specific rate schedules similar to Rate Schedule 9 following discussions between the Company and the affected customer. Although the Commission declines to establish a separate rate schedule for electric generation customers in this proceeding, the Public Works Commission remains free to propose such a schedule along with appropriate accompanying information in NCNG' next general rate case.

In his prefiled testimony and exhibits, Company witness Teele proposed to modify Rate Schedule 6 to make it available to any customer "...having requirements for natural gas for boiler fuel or electric power generation over 15,000 therms per day (over 1,500 MCF per day) which meet the criteria set forth in North Carolina Utilities Commission Rule R6-19.2 for priorities 7, 8, and 9..." Since PWC is currently served under Rate Schedule 6, the Company's proposed modification is a matter of form. In view of the fact that NCNG's proposed change would more accurately describe the type of customers receiving service under Rate Schedule 6, the Commission concludes that the Company's proposal is reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 138

After a careful consideration of all the evidence presented in this proceeding, the Commission concludes that the rate design approved by this Order, as set forth in Appendix A, is reasonable and appropriate.

NCNG has been granted a general rate increase of $2,564,512 in this proceeding, which has been allocated among the various customer rate classes as follows:

	Annual Revenue Increase(Decrease)	Percent of Total
Residential	$ 2.16 million	84%
Commercial	.44 million	17%
Industrial	.41 million	16%
Municipal	(.53) million	-21%
Miscellaneous	.09 million	4%
Total	$ 2.57 million	100%

Under the rate design adopted by the Commission in this case, residential and commercial rates have been increased by a total of $2.6 million, while industrial and miscellaneous rates have been increased only slightly and municipal rates have been decreased. Both NCNG and the Public Staff recommended a rate decrease for municipal customers. The Commission has adopted the percentage decrease for municipal customers recommended by the Company. Except for the rate increase of only 0.6% placed on the industrial rate class, substantially all of the revenue increase granted to NCNG in this docket was placed on residential and commercial customers. This same type of rate design was also generally followed in NCNG's last general rate case in 1986, when substantially all of the rate increase was placed on residential and commercial customers whose rates were increased by approximately 16% and 6%, respectively, based upon an overall average rate increase of 4.72%. Considering the magnitude of the rate increases placed upon residential and commercial customers in this case and the 1986 case, the Commission concludes that the approved rates result in a fair distribution of the overall rate increase granted to NCNG among the customer classes and will result in class rates of return that are both positive and closer to the overall rate of return than the returns under existing rates. The approved rates also reflect the relative risk to the Company of serving each class of customers. In reaching this decision, the Commission has given careful consideration to and has weighed and balanced all of the factors discussed by this Commission in previous Orders and approved by the North Carolina Supreme Court in the opinions cited in this Order. The rates to be developed in accordance with Appendix A will produce approximately the following percentage rate changes by customer class, shown both before and after the latest PGA filing:

RATE SCHEDULES BY CUSTOMER TYPE	AFTER LATEST PGA FILING	BEFORE LATEST PGA FILING
RESIDENTIAL	7.4%	-9.0%
COMMERCIAL	1.9%	-16.1%
INDUSTRIAL	0.6%	-10.6%
MUNICIPALS	-2.6%	-8.6%
TOTAL COMPANY	1.8%	-10.8%

The rates to be calculated under the constraints of Appendix A are just and reasonable and do not unreasonably discriminate among the various classes of NCNG's customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 139 - 140

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Teele and Public Staff witness Curtis.

Public Staff Witness Curtis filed a fixed gas cost allocation by rate class in his supplemental testimony filed October 8, 1991, in Revised Exhibit G. The purpose of this fixed gas cost allocation calculation is to show the recovery rates by rate class that will be effective for recovering NCNG's fixed gas costs. In addition to using the recovery rates for purposes of a fixed gas cost true-up, the fixed gas cost recovery rates will be used in calculating the portion of the bill to which the Weather Normalization Adjustment factor will apply. NCNG, through witness Teele, also provided a fixed gas cost allocations by rate class which would be used for recovery rates by rate class and for weather normalization. The recovery rates proposed by the Public Staff and NCNG are similar in that Rate 1 (Residential) customers would be charged the highest recovery rate and industrial customers in Rate 6 would be charged the lowest fixed gas cost recovery rate.

The Commission finds that the Public Staff's methodology is more reflective of how the costs are incurred. Accordingly, the Commission concludes that the fixed gas costs recovery rates proposed by the Public Staff are appropriate for use in calculating fixed gas cost recovery in Riders A and B and for the implementation of the Weather Normalization Adjustment factor (Rider C).

The applicable rate per dt are as follows:

Rate Schedule 1	$.9419
Rate Schedule 2	.6781
Rate Schedule 3A	.3984
Rate Schedule 3B	.3407
Rate Schedule 4	.3992
Rate Schedule 5	.2476
Rate Schedule 6	.2174
Rate Schedule 9	.3508
Rate Schedule 10	.4321
Rate Schedule RE-2	.5635
Rate Schedule S-1	.2458
Rate Schedule SM-1	.2933

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 141 - 146

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Teele and Public Staff witness Curtis.

The Company, the Public Staff and CUCA all supported the concept of summer/winter differentials in filed tariff rates.

Describing it as a major rate design change, witness Teele proposed summer/winter rates for all rate schedules. He recommended that this be accomplished by establishing separate Weighted Average Cost of Gas (WACOG) for the summer and winter. He originally testified that this change is necessary to reflect the seasonal swings in demand as well as changes in the commodity cost of gas and prices of alternate fuels. In his additional supplemental direct testimony, witness Teele changed his rate design so that the entire summer/winter differential is due entirely to seasonal changes in commodity gas costs.

Witness Curtis testified in his updated testimony that the summer/winter differential in tariff rates should reflect the seasonal differential in fixed gas costs, not commodity.

A summer/winter differential should reflect the fact that costs other than the commodity cost of gas (such as storage fees, injection and withdrawal charges and capacity charges) experience seasonal swings. Increased costs related to increased demand in the winter should be assigned to the various rate classes and included in the summer/winter differential in the approved tariff rates. Seasonal differences in the commodity cost of gas generally apply to all classes of customers and have historically been recognized through PGA proceedings. The Commission concludes that the Company did not provide a compelling argument for accepting its proposal to reflect seasonal changes solely in the commodity cost of gas, with no consideration given the seasonal changes in demand-related costs. A differential of the magnitude recommended by the Public Staff is appropriate except for Rate Schedules 9 and T-5, which have been approved by the Commission as filed.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 147 - 159

The evidence supporting these findings of fact is contained in the testimony of NCNG witness Teele and Public Staff witness Curtis.

NCNG witness Teele originally proposed to calculate transportation rates by subtracting a seasonal weighted average cost of gas from his proposed tariff rates which contained a summer/winter differential based on changes in the commodity cost of gas and changes in demand or fixed costs. As shown by the example on Public Staff Teele Rebuttal Exhibit 4, this resulted in a much smaller differential between the summer and winter transportation rates than in the summer and winter tariff rates.

In his additional supplemental direct testimony, witness Teele changed his rate design so that the entire summer/winter differential in his proposed tariff rates is due entirely to seasonal changes in gas costs. Because the differential in both the tariff rates and the weighted average cost of gas (WACOG) reflect the seasonal differential in the commodity cost of gas, the subtraction of NCNG's proposed summer and winter WACOGs then yielded transportation rates that were the same for the summer and winter periods. This also is illustrated on Public Staff Teele Rebuttal Exhibit 4.

Public Staff witness Curtis testified that his proposal to subtract an annual average cost of gas from tariff rates that properly reflect the summer/winter differential in demand-related costs yielded full margin transportation rates as the Commission has defined that term for the past decade.

He further testified that his methodology maintains the same summer/winter differential for a transportation customer as for a sales customer paying the filed tariff rate.

As was noted previously in the discussion of summer/winter differentials, seasonal differences in commodity costs have historically been recognized through the use of the Purchased Gas Adjustment. The Commission concludes that the Company did not present a sufficiently compelling argument to convince the Commission to depart from historical rate design methodology.

With respect to the continuation of full margin transportation rates, the Commission reiterates its previous conclusions that full margin transportation rates are fair and reasonable and are not discriminatory. In the past the Commission has found no justification for a difference between the margins earned on the four North Carolina local distribution companies' sales rate schedules and their transportation rate schedules. The utility should be neutral as to whether a customer transports or buys natural gas under a filed tariff rate. In order for a utility to be neutral, a transportation customer should pay the same fixed costs it would pay as a sales customer. In making this determination, the Commission has considered all of the relevant factors it considered in designing the sales rates.

It is obvious to the Commission and supported by NCNG's own testimony that the services performed by NCNG for a customer who transport are virtually the same services it performs for a sales only customer. The evidence is uncontradicted that all but one of NCNG's customers who pay transportation fees to transport their own supply of natural gas have contracts for interruptible service with an interstate pipeline. Interstate pipeline transportation is unavailable in the winter except to customers with contracts for firm service because of capacity constraints. Interruptions can occur at other times, such as when Transco is replenishing its supplies in storage further north or when there is a hurricane in the Gulf of Mexico. NCNG's transportation customers become its sales customers whenever they cannot transport their own supplies of natural gas, unless they switch to their alternate fuels.

The North Carolina Supreme Court has held that it was not unjust and unreasonable as a matter of law for a utility to earn the same margin on transported gas that it earns on its own retail sales of gas. State ex rel. Utilities Commission v. N.C. Textile Manufacturers Association, 313 N.C. 215, 328 S.E.2d 264 (1985). The Commission therefore concludes that full margin transportation rates are just and reasonable and do not unreasonably discriminate among NCNG's various classes of customers.

Concluding that full margin transportation rates are appropriate does not resolve the issue of whether the Commission's traditional method of calculating transportation rates should be maintained or NCNG's proposed new methodology accepted. Having found that a summer/winter differential in tariff rates should reflect the seasonal changes in demand-related costs and that NCNG's proposal to reflect only the seasonal differences in the commodity cost of gas in tariff rates is unreasonable, the conclusion that NCNG's proposed new methodology of calculating transportation rates is unreasonable must follow. Under NCNG's proposed methodology a customer would not pay the same amount of fixed costs while transporting as it would pay when it switched to being a sales customer in the winter or at other times its transportation on an interstate pipeline was interrupted. Thus, NCNG's proposed methodology does not produce full margin transportation rates, as that term previously has been defined and adopted by this Commission and upheld by the Supreme Court, and therefore does not produce transportation rates that are just and reasonable.

The Commission previously has concluded that a seasonal differential of the magnitude recommended by the Public Staff is appropriate, except in regard to Rate Schedules 9 and T-5. The Commission further concludes that an annual weighted average cost of gas of $2.5293/dt should be used to calculate transportation rates, as recommended by the Public Staff. The transportation rates resulting from the subtraction of this annual cost of gas (along with gross receipts tax and any temporary increments or decrements) from the seasonal tariff rates approved herein cause the transportation customers to pay the same fixed cost differential between the summer and winter seasons as the sales customers. They constitute fair and reasonable transportation rates that do not unreasonably discriminate among NCNG's various classes of customers.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 160-164

INTRODUCTION

The evidence for these findings of fact is found in the testimony and exhibits of Public Staff witness Hoard and Company witnesses Teele and Wells.

Company witness Teele proposed essentially the same Industrial Sales Tracker (IST) as that approved by the Commission in the Company's last general rate case, Docket No. G-21, Sub 255, with one significant modification. Mr. Teele proposed that the Sub 255 IST be modified to incorporate capital costs related to IST customer growth. This modification is found at section (or numbered paragraph) thirteen of the Company's proposed IST.

Public Staff witness Hoard recommended two major modifications to the Company's proposed IST: (1) reduce the base period margin by the IST portion of demand and storage charges to arrive at an amount he refers to as "base period gross profit," and (2) delete numbered paragraph thirteen of the Company's proposed IST. He also recommended several minor wording changes.

UNCONTESTED ISSUES

Minor Wording Changes

Mr. Hoard recommended several minor wording changes in the Industrial Sales Tracker - Rider A. The Company did not dispute any of these minor wording changes.

Since Public Staff witness Hoard's recommended minor wording changes are reasonable, and no evidence has been offered to the contrary, the Commission finds these changes appropriate.

Exclusion of Demand and Storage Charges

Demand and storage charges are defined in the approved Rider B Purchased Gas Adjustment Procedures as follows:

> "Demand and Storage Charges shall mean all charges payable by the Company to others for the transportation or storage of system supply gas which are not based on the actual volume of gas purchased, stored or transported by the Company. However, if the service being purchased is in the nature of capacity or storage, the related cost will be deemed a demand or storage charge even if it is to be paid on the basis of actual volumes purchased or transported."

Public Staff witness Hoard recommended that the base period margin be reduced by the IST portion of demand and storage charges to arrive at an amount which he refers to as the "base period gross profit." Mr. Hoard explained his recommendation as follows:

> "Since demand and storage charges incurred by the Company are trued-up with those recovered in my recommended PGA Procedures, it would be inappropriate to true-up the IST portion of those same costs through the IST mechanism. In my opinion, requiring a true-up of demand and storage charges through the PGA and IST would result in double-counting. I recommended that the IST be modified instead of the PGA Procedures, so that NCNG's PGA Procedures can conform with the other gas companies as nearly as possible."

Company witness Teele agreed with Public Staff witness Hoard on this matter.

The Commission finds Mr. Hoard's recommendation to be reasonable and appropriate, and therefore concludes that demand and storage charges should be excluded from the IST base period margin, and that the resulting amounts be referred to as "base period gross profit."

PURPOSE OF THE IST

The parties disagreed on the purpose of the IST and who is protected by the IST. Due to potential policy impacts, the Commission will now address this issue.

Public Staff witness Hoard testified that the purpose of the IST is to stabilize the Company's margin on the sale or transportation of gas to industrial customers having heavy oil as their alternative fuel. He further testified that "the IST protects the Company against margin losses due to volume or margin rate declines on transactions with IST customers."

Company witness Teele testified that the IST also "protects core market customers when the price of heavy oil increases and/or IST volumes increase." In support of this point, Mr. Teele stated that the IST has returned several million dollars to core market customers over the years, including $3.7 million in the 12-months ended October 31, 1990, and $8.0 million for 10-months ended August 31, 1991.

Public Staff witness Hoard disagreed with Mr. Teele. Mr. Hoard testified that the refunds to non-IST customers occurred because the IST base period margin set in the last rate case included significant IST volumes priced-out at rates below tariffed rates, and if the IST volumes were priced-out at tariffed rates, it is likely that there would have been a surcharge on non-IST customers instead of a refund. Mr. Hoard also testified that the IST allows the Company to recover from non-IST customers margin losses due to IST price discounts or volume losses.

The Commission has reviewed the evidence on this matter and concludes that the purpose of the IST is to stabilize the Company's gross profit on the sale or transportation of gas to industrial customers having heavy oil as their alternative fuel, and that the IST protects the Company against gross profit losses due to volume or gross profit rate declines on transactions with IST customers. The Commission further concludes that the IST also benefits core market customers when the price of heating oil increases and/or IST volumes increase.

PARAGRAPH THIRTEEN

Another area of disagreement between the Company and the Public Staff concerns Company witness Teele's proposal at numbered paragraph thirteen of his proposed Rider A Industrial Sales Tracker to incorporate the capital costs related to IST customer growth in the IST base period gross profit.

Mr. Teele testified that paragraph thirteen should be included in the IST for the following reasons:

> "(1) It is equitable, and it is necessary in order for the Company to expand without being penalized and/or to be <u>required to file general rate cases every year.</u>
>
> (2) There is substantial pressure on our Company to expand into unserved areas and the provisions contained in paragraph thirteen are one way to help make that happen without <u>the necessity to have frequent and costly general rate cases as apparently the Public Staff would prefer that we have.</u>" (Emphasis added.)

Mr. Teele also offered the following testimony in support of his proposal:

> "When we add new industrial non-IST customers, we are allowed to retain as revenues whatever margin we can earn up to the full tariff rates from the sale of that gas. What we are asking for in Paragraph 13 is a similar-type arrangement in which the Company would not be penalized for adding new investment to serve large industrial customers having heavy oil as their alternative fuel. Based on our prior experience and industrial prospects now in the works, there would likely be no more than three or four new IST customers added each year. Therefore, <u>we are not likely to have significant changes in the IST base period margins each year resulting from the application of Paragraph 13.</u>" (Emphasis added.)

Public Staff witness Hoard recommended that the Commission not adopt the Company's paragraph thirteen proposal for the following reasons:

"(1) Incorporating the costs of growth into the IST base period [gross profit or margin] is inconsistent with the purpose for having an IST. The purpose of the IST is to ensure that the Company collects the base period margin determined in this rate case proceeding. Reflecting the costs of growth in the base period margin ensures that the Company will collect a base period margin which is <u>greater than</u> that determined by the Commission in this rate case proceeding. The effect of NCNG's proposal would be similar to adding rate base and non-gas expenses to its rate structure without coming in for a general rate case.

(2) It is inappropriate to incorporate growth in the IST base period margin without analyzing other cost of service factors. The base period margin should be increased for growth only in rate case proceedings, since a rate case proceeding is the appropriate forum for analyzing all cost of service components. If the costs of growth are incorporated in the IST formula, NCNG could show an undercollection of IST base period margins at the same time it is earning large profits in other markets. In a rate case proceeding, these two events could be offset against each other without impacting customers' rates. Under the Company's proposal, however, the Company would be permitted to collect the IST undercollection through a surcharge on customers' rates.

(3) The current IST has not kept the Company from earning its allowed rate of return on equity. Since the Company's last rate order from the Commission on November 10, 1986, the Company has earned the following rates of return on common equity:

Fiscal Year Ended	Return on Equity %
September 30, 1987	16.7%
September 30, 1988	17.9
September 30, 1989	18.5
September 30, 1990	15.7

These rates of return compare to the Commission's 1986 allowed rate of return on equity of 14.0%. It should be noted that these lofty returns were earned despite close to normal weather and well-above average residential customer growth rates. These greater-than allowed returns were earned even though the operating environment was adverse.

In my opinion, the current IST formula does not need to be modified to provide greater protection against deterioration in earnings due to growth.

(4) The Company's IST proposal suffers from essentially the same flaw as the Sub 235 IST formula which was overturned by the Supreme Court of North Carolina. That IST excluded new IST-type customer volumes from the under/overcollection calculation of IST base

period margins. The Commission's purpose for excluding those new customers from the IST was to allow NCNG to earn some return on the new plant investments it would need to make to attach new customers to its system.

Although the technical mechanics of the Company's current IST differ from the Sub 235 IST, the purpose and result of the current proposal are essentially the same as the Supreme Court rejected in the Sub 235 IST."

The Commission is not convinced by the Public Staff's last argument. In Docket No.G-21, Sub 235, both the Public Staff and NCNG proposed the exclusion from the IST of new customers who have heavy oil as their alternate fuel in order to allow NCNG to earn some return on new plant investment which might be necessary to connect such customers and thus encourage expansion. The Commission excluded all new IST-type customers on that basis. In State ex rel. Utilities Commission v. N.C. Textile Manufacturers Association, Inc., 313 N.C. 215, 328 S.E.2d 264 (1985), the Supreme Court held that excluding new IST customers from the IST was unjust and unreasonable as a matter of law. The Court instructed the Commission to include new industrial and large commercial customers with heavy fuel oil as an alternate fuel in any IST which it might adopt. However, the Supreme Court did not reject the purpose of allowing recovery of cost. The Court simply determined that it was improper to allow such an "imprecise method" as retaining all profits from new customers. 313 N.C. at 228, 229.

The Commission finds the Public Staff's other arguments more convincing. The Commission's conclusion on the appropriateness of approving IST numbered paragraph thirteen hinges on the following issues:

(1) Is it equitable to exclude paragraph thirteen from the IST?

(2) Does the Company's current IST discourage industrial growth?

(3) Is it appropriate to incorporate into the IST a formula which would automatically build into rates a rate of return on new investments?

The Commission will now evaluate each of these issues.

Issue (1): Is it equitable to exclude paragraph thirteen from the IST?

The Commission has previously concluded that the IST protects NCNG from gross profit losses due to price discounts or volume declines on transactions with customers having heavy oil as their alternative fuel. The non-IST customers are protecting NCNG against the possible loss of gross profits from IST customers. The cost to NCNG of this is the forfeiture of gross profit gains from IST customers until the Company's next general rate case.

Also, paragraph thirteen is contrary to the Commission's policy which has been not to allow recovery of capital costs outside of rate cases. Other LDCs are not allowed to adjust their rate structure to recover capital investment related to growth, except in rate cases, and it would not be fair to give it just to NCNG. If NCNG wants to retain gross profits from new customers as an offset to the capital costs of adding new customers, the fair approach would be simply to eliminate the IST. This is how it works with other LDCs. NCNG has chosen to keep the IST, and the IST uniquely protects NCNG against gross profit loss from alternate fuel customers. Therefore, it is only fair that the IST continue to pass gross profit gains on to the non-IST customers who pick up the gross profit losses.

We conclude that it is equitable to exclude numbered paragraph thirteen from the IST.

Issue (2): Does the Company's current IST discourage industrial growth?

From a short-term perspective, the Company's current IST leaves NCNG with little financial incentive to add additional IST customers to the system, since the Company doesn't receive any margins from these customers until the Company's next rate case. However, the life of the investment required to hook-up IST customers is more important. The Company could be giving up short-term profits if it invested funds to hook-up the new IST customer, but the Company would benefit from long-term profits as well as load factor improvements. We conclude that the Company's current IST should not discourage industrial growth.

Issue (3): Is it appropriate to incorporate into the IST a formula which would automatically build into rates a rate of return on new investment?

The PGA Procedures approved herein allow NCNG to recover from ratepayers all of its prudently incurred gas costs. The PGA Procedures also protect the Company against negotiated losses on non-IST volumes due to price discounting. In addition, the current IST ensures the Company that it will collect a set dollar amount of gross profit from customers with the ability to use heavy oil as an alternative fuel. These trackers, combined, provide protection by covering a very substantial portion of the Company's cost of service. Paragraph thirteen would provide additional coverage in the form of a rate of return tracker for IST customers. This occurs because the proposed change to the IST would allow NCNG to keep the approved rate of return, and other capital costs related to its investment in new IST customers, as an add-on to the gross profit level that is virtually guaranteed by the IST mechanism.

We conclude that it would be inappropriate for the IST formula to virtually guarantee a rate of return on new investment. Rate cases are the appropriate forum for incorporating growth into the Company's rates, since they are the only forum where all cost of service factors are evaluated. Otherwise, under paragraph thirteen, ratepayers could be required to pay higher rates to cover additional IST investment, while at the same time the Company was earning a higher than allowed rate of return in the non-IST market. The potential to earn a return higher than the allowed rate of return could occur due to a variety of reasons. One possible scenario would be if a non-IST customer, such as the Fayetteville Public Works Commission, used significantly more gas than is reflected in the end-of-period volumes in this case. The evidence in this case shows that NCNG has consistently earned well above its allowed return even without incorporating the cost of growth into its IST base period margin. Moreover, a formula that tracks rate of return on new investment would be a radical departure from long-established Commission policy.

SUMMARY CONCLUSION

The Commission concludes that it is not appropriate to incorporate growth into the IST base period margin. Therefore, the proposed section thirteen should not be adopted. Based on the foregoing, the Commission concludes that the Rider A Industrial Sales Tracker (IST) as recommended by the Public Staff is reasonable and should be included in the rate structure of the Company.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 165 - 180

INTRODUCTION

The evidence for these findings of fact is found in the testimony of Public Staff witnesses Hoard and Curtis and Company witness Teele. In addition, the Commission takes judicial notice of the official record in Docket No. G-100, Sub 58.

Public Staff witness Hoard recommended numerous modifications to the Company's proposed Rider B PGA Procedures. Company witness Teele commented as follows regarding these modifications:

> "NCNG generally agrees with Public Staff's revisions to the Purchased Gas Adjustment Procedures - Rider B. However, we want these tariff provisions to be subject to the outcome of the rulemaking proceeding in Docket No. G-100, Sub 58. All four of the North Carolina LDCs filed joint comments with the Commission on September 23, 1991 in this docket. In those comments, some positions are taken by LDCs that differ from Hoard Exhibit 1. Chief among these difference are these two:
>
> (1) Certain definitions are different from those drafted by witness Hoard.
>
> (2) We believe that new storage or pipeline demand or capacity costs should be included in gas costs to be recovered in rates in this PGA rider subject to the outcome of the rulemaking proceedings in Docket No. G-100, Sub 58."

In addition, Company witness Teele stated that he agreed with Public Staff witness Hoard's recommendation regarding the disposition of margins earned by Cape Fear Energy Corporation on the sale of natural gas to transportation customers on the NCNG system and his recommendation regarding negotiated losses.

In response to Public Staff witness Hoard's recommendation that all additional margins earned on off-system gas sales be credited to the deferred account, Mr. Teele proposed that only 50% of the additional margin on these sales be recorded in the deferred account. Also, Mr. Teele proposed that the interest rate on the deferred account be set at the lesser of 10% or the prime interest rate, as compared with Public Staff witness Hoard's recommendation that the interest rate be set at 10%.

UNCONTESTED ISSUES

Several of the PGA Procedures modifications were uncontested by the parties.

Since the Public Staff's position is reasonable, and no evidence was offered to the contrary, the Commission concludes the following:

(1) The PGA Procedures should require that the Company compare the actual commodity cost of gas incurred, expressed on a per unit basis, with the Base Cost of Gas, and that the per unit difference should then be multiplied by the volumes purchased, net of storage injections and withdrawals, to determine the under or overrecovery of commodity gas costs to be recorded in the Deferred Gas Cost Account.

(2) The PGA Procedures should require that the Company compare the demand and storage charges collected in the Company's rates to the actual demand and storage charges incurred each month, and that any difference be recorded in the Deferred Gas Cost Account.

(3) The Company should record in the Deferred Gas Cost Account the margins earned by Cape Fear Energy Corporation for gas marketing or brokering services provided to transporting end users, less $.02 per dekatherm.

(4) The Company should record in the Deferred Gas Cost Account all excess margins earned on sales of emergency gas to non-IST customers. The excess margins are computed by comparing all revenues received by the Company, less gross receipts taxes, to the revenue less gross receipts taxes which would have been received if the quantity of gas had been sold under the customer's regular rate.

(5) The Company may negotiate with non-IST commercial and industrial customers on its sales and transportation rates to avoid the loss of deliveries to these non-IST customers. All margin loss from these customers shall be accumulated in the Deferred Gas Cost Account. Such margin loss shall be based on the Company's tariff rates.

(6) The Company should true-up on an annual basis the gas costs associated with Company Use and Unaccounted For Volumes. This true-up should be computed by comparing the actual Company Use and Unaccounted For Volumes during the true-up period with the Company Use and Unaccounted For Volumes reflected in rates during the twelve-month true-up period, and multiplying the difference by the applicable Base Cost of Gas. The first annual true-up period should be the year ending June 30, 1993.

(7) The Company should maintain separate account categories for Deferred Gas Cost Account transactions that relate to (1) all customers and (2) sales only customers.

(8) The Company should analyze the balances in the current deferred gas cost accounts on a first-in, first-out basis consistent with the Commission's definition of demand and storage charges and commodity gas costs set forth in the approved PGA Procedures. This analysis should be performed concurrent with this Order's date.

ADDITIONAL PIPELINE CAPACITY AND STORAGE

Mr. Teele and Mr. Hoard differed on whether the costs of capacity and storage that are added after the rate case should be included in the demand and storage charge true-up. Public Staff witness Hoard also offered the following testimony regarding this issue:

"In Piedmont's last general rate case, the issue of a true-up for added capacity and storage charges was postponed for decision in the G-100, Sub 58, rulemaking. The Public Staff would not object if the Commission likewise decided for NCNG that the issue of how to handle added storage and capacity should be addressed in the Commission's pending rulemaking proceeding. Monies collected by the Company for added capacity would then be collected on a provisional basis, pending resolution of this issue in G-100, Sub 58."

Company witness Teele agreed with the Public Staff's suggestion to defer this issue until the Commission's Order in Docket No.G-100, Sub 58.

The Commission takes judicial notice that on July 8, 1991, the General Assembly enacted Chapter 598 of the 1991 Sessions Laws. This legislation amends Chapter 62 of the General Statutes by adding G.S. 62-133.4. The statute authorizes the Commission to allow rate changes "occasioned by changes in the cost of natural gas supply and transportation..." G.S. 62-133.4(e) provides that the "costs" subject to the statute shall be "defined by Commission rule or order and may include all costs related to the purchase and transportation of natural gas to the natural gas local distribution company's system."

The Commission has initiated Docket No. G-100, Sub 58, to define "costs" for purposes of G.S. 62-133.4 and to provide for the implementation of this statute. Since the pending rulemaking in G-100, Sub 58, will address the issue of additional capacity and storage for all the LDCs, the Commission concludes that resolution of this issue for NCNG should coincide with the rulemaking for all LDCs instead of in the present docket. This approach is consistent with the Commission's Order in Piedmont's rate case, Docket No. G-9, Sub 309, and in Public Service's rate case, Docket No. G-5, Sub 280. To protect all parties, it is reasonable for NCNG to collect any costs of added capacity or storage through the Rider B procedures, but any monies so collected which are associated with additional pipeline capacity and storage should be placed in a deferred account pending their disposition by the Commission in Docket No. G-100, Sub 58.

BASE COST OF GAS

Public Staff witness Curtis has incorporated in his rate design recommendation an annual Base Cost of Gas of $2.5293 per dekatherm. Company witness Teele, in contrast, proposed a seasonal Weighted Average Cost of Gas

(WACOG) approach in his rate design recommendation. The WACOG approach results in a summer Base Cost of Gas of $2.2205 per dekatherm and a winter Base Cost of Gas of $2.7348 per dekatherm.

Besides the rate design aspect, the parties also differ on the commodity cost of gas amount and the volumes of gas purchased. Below is presented a summary of the Company and Public Staff annual Base Cost of Gas amounts:

	Company	Public Staff
Commodity cost of gas	$81,098,255	$80,854,237
Purchases (dekatherms)	32,079,791	31,967,237
Base Cost of Gas	$ 2.5280/dt	$ 2.5293/dt

The Commission has concluded elsewhere herein that it is appropriate for purposes of this case to use a single annual Base Cost of Gas rate instead of the two seasonal Base Cost of Gas rates proposed by the Company. In addition, the Commission concluded that the appropriate annual Base Cost of Gas for use in this proceeding is $2.5293 per dekatherm. Based on these findings, the Commission therefore concludes that the Base Cost of Gas appropriate for use in conjunction with the PGA Procedures is an annual rate of $2.5293 per dekatherm. This rate is computed by dividing the annual commodity cost of gas of $80,854,237 by the annual gas supply volumes of 31,967,273 dts.

FIXED CHARGE RATE

The Fixed Charge Rate is the demand and storage costs, expressed on a per dekatherm basis, applicable to each rate class. Rates are not based solely on cost of service, but it is still necessary to impute a certain level of demand and storage costs to each rate class for purposes of the Weather Normalization Adjustment, for determining the IST gross profits, and for calculating the demand and storage charge true-up under the Rider B PGA procedures. The issue in controversy is (1) how post-rate case changes in the amount of demand and storage charges should be incorporated in the Fixed Charge Rates and (2) how overcollections and undercollections of demand and storage charges should be flowed back to ratepayers or collected from ratepayers.

Public Staff witness Hoard recommended that the Fixed Charge Rate be adjusted on a flat per dekatherm basis whenever the amount of demand and storage charges collected in the Company's rates is changed in a PGA. Mr. Hoard reasoned that:

(1) This approach is consistent with how demand and storage charge changes have been reflected in rates outside of general rate case proceedings in the past.

(2) This approach is easy to administer, and PGA changes can be processed in a relatively short period of time.

(3) Rate differentials between rate classes are maintained with this approach.

(4) This approach is currently used for Piedmont and is proposed for Public Service.

During the cross-examination of Public staff witness Hoard, CUCA raised the issue of spreading changes in demand and storage charges between the rate classes based upon the ratios of the rate class - specific fixed charge rates determined by cost of service in this rate case, instead of on a flat per dekatherm basis. CUCA also raised the issue of how demand and storage charge underrecoveries, which are recorded in the Deferred Gas Cost Account, are to be recovered from ratepayers. CUCA questioned the Public Staff's recommendation that these underrecoveries be collected by the Company through a flat per dekatherm increment in rates.

Public Staff witness Hoard responded that the PGA Procedures should be reasonably accurate but shouldn't require the Commission to go through the same procedures as a rate case. Mr. Hoard explained:

> "We don't want to have a four-day hearing to decide gas-cost adjustments and how much to change those. We need to change them instantaneously or pretty quickly. If we were to go through the cost-of-service study, it would take us some time to work up that cost-of-service study, and it would take the Company some time to prepare that, and if we had to have a hearing here--maybe the same people would be here, and maybe you'd be crossing me or Mr. Curtis again...and we would have some discussion about what is the appropriate mechanism to allocate, you know, this service and that service. We'd be going through the same, or a very similar, cross-examination in that proceeding. I think that would defeat the purpose of having a gas cost adjustment procedure that is quick."

Mr. Hoard also pointed out the expedited nature of PGA proceedings and the impracticality of holding a "full-blown hearing to litigate whether the cost of service is accurate for the PGA proceeding." Mr. Hoard testified that it would be inappropriate to rely upon the proportional differences in fixed charges per class from the cost-of-service study used in the last general rate case because that would not recognize all of the factors that changed, such as demand and volume changes.

Company witness Wells also provided some testimony relevant to the issue of how changes in demand and storage charges should be reflected in PGA proceedings. Mr. Wells testified that 85% of volumes associated with the new Southern Expansion capacity went to industrial customers during the 1990-91 winter season. Use of old rate case cost-of-service ratios would have assigned a much lower portion of the new capacity costs to industrial customers than 85%. Mr. Wells' testimony indicates that the cost responsibility for a new fixed cost may be entirely different from the cost-of-service allocations for old fixed costs. Also, a change in the fixed costs for existing services may occur at a time when the degree of utilization of those services by the various classes has shifted greatly since the cost-of-service study was performed. In both situations, CUCA's and NCNG's apparent desire to preserve the proportional differences in fixed costs from the rate case cost-of-service study would necessarily cause an improper allocation between the classes. The only solution would be to perform a new cost-of-service study every time fixed costs changes. This is not practical to do between rate cases.

During CUCA cross-examination of Company witness Teele, Mr. Teele agreed with the CUCA suggestion that the Commission should consider the development of some process that tracked fixed gas costs through PGA proceedings on a cost-of-service basis rather than a flat per dekatherm basis.

CUCA also questioned Witness Hoard with regard to how an underrecovery of fixed gas costs is recovered from customers. CUCA suggested that any underrecovery of fixed gas costs should be collected from customers with customer class-specific rates, instead of the flat per dekatherm approach recommended by Mr. Hoard. Mr. Hoard stated that the deferred accounts are presently not maintained on a customer class basis.

The Commission has reviewed the evidence and concludes that the PGA Procedures should require that adjustments to the Company's Fixed Charge Rates due to changes in demand and storage charges, and increments and decrements resulting from past demand and storage charge underrecoveries or overrecoveries, should both be computed on a flat per dekatherm basis. This approach is reasonable and proper because it will maintain on an absolute basis the rate class differentials determined in this rate case, is easy to administer, and is consistent with the procedures utilized by the other local distribution companies regulated by this Commission.

The Commission does note, however, from the filings made by the parties to Docket No. G-100,Sub 58, that these two issues remain unresolved in such rulemaking proceeding and will be ultimately resolved by further decision of the Commission in that docket.

INTEREST RATE ON THE DEFERRED ACCOUNT

Company witness Teele proposed that the interest rate on the Deferred Gas Cost Account be set at the lesser of 10% or the prime interest rate. Mr. Teele reasoned that "it doesn't make good business sense to be required to pay customers at above-market interest rates."

Public Staff witness Hoard recommended that the interest rate on the Deferred Gas Cost Account be set at annual rate of 10%, and that the interest be compounded monthly. Mr. Hoard testified that this would be consistent with the interest rate approved for Piedmont and Public Service.

The Commission notes that monies in the Deferred Gas Cost Account represent amounts owed by the Company to customers. These monies are to be flowed back to customers.

The Commission concludes that the interest rate on the Deferred Gas Cost Account should be accrued each month on the average balance in the Deferred Gas Cost Account at the annual rate of 10%, compounded monthly.

SALES OF GAS TO OFF-SYSTEM ENTITIES

NCNG has earned margins on off-system sales of LNG to various off-system entities, including Public Service Company of North Carolina Inc., over the last several years. For example, during the test year, NCNG received $199,006 of margins on sales of LNG to off-system entities other than Public Service. Neither the Company nor the Public Staff's revenues and expenses reflects, however, any off-system sales, other than certain firm sales to Public Service.

Public Staff witness Hoard recommended that the Company record in the Deferred Gas Cost Account all additional margins earned on sales of gas to off-system entities, including Public Service Company of North Carolina. The only exception is the firm sale to Public Service that has been pro formed into revenues in this case. The additional margins are computed by comparing all revenue received by the Company, less the cost of gas and gross receipts taxes, to the revenue less the cost of gas and gross receipts taxes reflected for sales of gas to off-system entitles, including Public Service Company of North Carolina, included by the Commission in the Company's last general rate case order.

Mr. Hoard supported his recommendation with the following testimony:

> "The entire cost of the Company's LNG facility is included in the Company's rate base, and the Company's on-system customers are paying the return, depreciation, and operating costs associated with the facility. It is inequitable for the Company's on-system customers to pay the entire costs related to the LNG facility without receiving the margins resulting from off-system gas sales."

Company witness Teele proposed that 50% of the margins on off-system sales, other than to Public Service Company, be credited to the deferred account. Mr. Teele offered the following testimony in support of his proposal:

> "As a compromise, we propose 50% as an equitable sharing. If off-system sales are going to be made, then the Company needs to have some economic incentive to make them. If our realized margin is going to be zero, then we effectively have no economic incentive to take the risk associated with such a sale. Many LDCs and municipal gas systems in the Southeastern United States have peak-day problems or other gas supply problems that we may be able to address. If we are allowed to retain 50% of the margin and our customers receive the benefit of the other 50%, then it seems to us that is a "win-win" situation that should be encouraged."

The Commission notes that the Company's ability to provide gas to off-system entities is the result of having capacity available beyond that required to serve the needs of its on-system customers. The Commission does not propose, in this proceeding, that any portion of the LNG facility be considered excess capacity, and be removed from rate base. However, it is abundantly clear that ratepayers should receive all of the margins on off-system sales of LNG, since they are bearing all of the costs related to the facility. We find that it would be inequitable for ratepayers to receive only 50% of the margins while at the same time bearing all of the costs.

Furthermore, the Commission rejects the argument that NCNG needs an "economic incentive" to make sales from its extra capacity and supply. The Company has a public service obligation to keep costs as low as possible for ratepayers. This obligation extends to flowing all margins from off-system sales back to ratepayers where the costs supporting those sales have been included in jurisdictional rates. NCNG's proposed 50%-50% "equitable sharing" of these margins would have ratepayers subsidizing non-jurisdictional profits for NCNG. Such a result would be improper.

With regard to sales of gas to Public Service Company of North Carolina, Inc., the Commission notes that the cost of service under approved rates reflects $1,833,102 of revenues and $569,092 in cost of gas for these sales. These amounts pertain solely to the Company's contractual obligation to provide 225,000 dekatherms of firm gas supply to Public Service. No amount has been reflected in revenues or the cost of gas under approved rates for sales of gas above and beyond the 225,000 dekatherms of NCNG's firm commitment to Public Service.

Of course, the actual cost of any gas sold to Public Service would be recovered from ratepayers by NCNG through its Rider B PGA Procedures. In addition, NCNG's cost for connecting with Public Service Company's system is included in rate base, and ratepayers are paying a return, as well as the operating costs and depreciation expense, associated with this transmission line. Therefore, since NCNG ratepayers are bearing all of the costs on sales of gas to Public Service Company, ratepayers should receive all the margins earned by NCNG on sales of gas to Public Service Company.

The Commission concludes the following:

(1) The Company should record in the Deferred Gas Cost Account all additional margins earned on sales of gas to off-system entities, including Public Service Company of North Carolina, Inc. The additional margins are computed by comparing all revenue received by the Company, less the cost of gas and gross receipts taxes, to the revenue less the cost of gas and gross receipts taxes reflected for sales of gas to off-system entities, including Public Service Company of North Carolina, Inc., included by the Commission in the cost of service in this proceeding.

(2) The cost of service in this proceeding reflects $1,833,102 of revenue, $569,092 of cost of gas, and $59,026 of gross receipts taxes, for a margin of $1,204,984 related to sales of gas to off-system entities. The entire amount reflected in this proceeding for sales of gas to off-system entities relates to firm sales of gas to Public Service Company of North Carolina, Inc.

SUMMARY CONCLUSION

The Rider B Purchased Gas Adjustment Procedures the Commission approves for NCNG, which are those as recommended by the Public Staff, are provisional subject to further order in Docket No. G-100, Sub 58. These PGA Procedures account for all the commodity costs of all gas supplies and services, and for all the fixed costs associated with gas transportation, storage, and other services. The approved PGA Procedures provide for a 100% true-up of all prudently incurred gas costs. However, all costs of storage and capacity services added after the hearing in this case should be recovered and placed in a separate deferred account for disposition per Commission Order in Docket No. G-100, Sub 58.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 181 - 183

The evidence for these findings of fact is contained in the testimony of NCNG witness Teele and Public Staff witness Curtis and the Motion filed by the Public Staff on November 15, 1991.

NCNG requested approval of a Weather Normalization Adjustment factor (WNA) which would be in effect for the winter period for Rate Schedules 1 and 2 and for the weather sensitive portions of Rate Schedules RE-2 and 10.

The Public Staff supported, through Public Staff witness Curtis, the removal of the 5% dead band originally proposed by NCNG and agreed with NCNG's new proposal for weather normalization adjustment.

On November 15, 1991, the Public Staff filed a Motion To Correct The WNA In The Proposed Rider C. The Motion, among other things, seeks to correct the WNA to reflect that the R term set forth therein is the approved rate less gas costs, which include both commodity costs and fixed costs as allocated to each rate class in the rate case for purposes of the WNA. The Public Staff points out that such corrections will conform NCNG's WNA to those approved for Piedmont and Public Service with respect to the R term. No response has been filed by any party to the Public Staff's Motion.

The Commission concludes that NCNG's WNA should operate in the same manner as the Weather Normalization Adjustment clause recently approved for Piedmont and Public Service.

The Commission concludes that the weather tracker, as set forth in the attachment to the Public Staff's Motion, is appropriate for implementation by NCNG in this general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 184

The evidence supporting this finding of fact is contained in the testimony of Company witness Teele and Public Staff witness Fernald. Ms. Fernald stated in direct testimony that in exchange for the Public Staff's agreement to the uncollectibles percentage of 0.18104%, the Company agreed to prepare an accounting manual within three years.

The Commission concludes that NCNG should prepare an accounting manual within three years from the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 185

The evidence supporting this finding of fact is contained in the testimony of Company witness Teele and Public Staff witness Fernald. Ms. Fernald recommended that NCNG employees indicate time spent on affiliated companies on time sheets or labor studies. Ms. Fernald stated that this would provide actual data for allocating payroll to affiliates.

Company witness Teele stated that NCNG would not accept the Public Staff's recommendation since NCNG does not believe that any executive time should be allocated to affiliated companies where executives do not spend a lot of time.

As discussed elsewhere herein, the Commission concluded that the Public Staff adjustment to allocate payroll to affiliates was reasonable and appropriate. The Commission concludes that NCNG should undertake a study to be incorporated with NCNG's next general rate case filing so as to determine an appropriate methodology to properly allocate NCNG's employees time spent on affiliated companies. It is improper for ratepayers to subsidize any amount of employee time spent on nonregulated affiliated companies, and it is appropriate that a proper methodology be devised that will permit an accurate allocation of such time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 186

The evidence supporting this finding of fact is contained in the testimony of Company witness Teele and Public Staff witness Fernald. Ms. Fernald recommended that NCNG prepare a square footage study within six months of the final order to determine the percentage of plant applicable to non-utility operations. Company witness Teele stated in cross-examination that the Company would probably prepare the study sometime in 1992.

The Commission concludes that NCNG should prepare a square footage study during 1992 for the purpose of providing current data for allocating plant to non-utility operations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 187

The evidence supporting this finding of fact is contained in the testimony of Company witness Teele and Public Staff witness Fernald. Ms. Fernald recommended that NCNG allocate payroll taxes, pension costs, group insurance, workers' compensation, accident and health, excess liability, and all other payroll related expenses to utility and non-utility accounts based on payroll distribution within 60 days of the final order. Company witness Teele indicated that the Company will change its accounting for these costs in the future.

The Commission concludes that NCNG should allocate on its books the expenses for payroll taxes, pension costs, group insurance, workers' compensation, accident and health, excess liability, and all other payroll-related expenses to accounts based on the distribution of payroll within 60 days of the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 188

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Fernald. Ms. Fernald recommended that NCNG record non-utility income taxes in non-utility accounts within 60 days of the final order.

NCNG did not offer any evidence in rebuttal to this proposal.

The Commission concludes that NCNG should begin recording non-utility taxes in non-utility accounts within 60 days of the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 189

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Fernald. Ms. Fernald recommended that NCNG use the overall return on investment approved in its most current rate case to calculate the Allowance for Funds Used During Construction (AFUDC). Ms. Fernald stated that under this methodology, the AFUDC calculation will be consistent with the capital structure, debt costs, and return on equity approved in NCNG's most recent rate case.

NCNG did not offer any evidence in rebuttal to this proposal.

The Commission concludes that NCNG should use as its Allowance for Funds Used During Construction rate the overall return on investment approved in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 190

The evidence for this finding of fact is found in the testimony of Public Staff witnesses Fernald and Hoard and Company witness Teele.

Public Staff witness Fernald recommended that the Company modify its book accounting procedures for storage-related fuel retainage costs by charging gas in storage inventory for these costs instead of charging its cost of gas account. Ms. Fernald testified that the book accounting treatment would then be consistent with her rate case treatment for the retainage costs, which in her opinion, should be the same whenever possible.

Public Staff witness Hoard provided an illustration of the Public Staff's recommended book accounting procedures for fuel retainage costs. Mr. Hoard also pointed out that this recommendation results in a better matching of revenues and expenses and is consistent with how Piedmont and Public Service account for fuel retainage costs.

Company witness Teele agreed with the Public Staff's recommended book accounting for fuel retainage costs.

The Commission concludes that it is proper for the Company to account for fuel retainage costs in the matter recommended by the Public Staff.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 191

The evidence supporting this finding of fact appears in the testimony of Public Staff witness Fernald and NCNG witness Teele. Ms. Fernald indicated that in 1990 NCNG sold some land for a gain of $344,395. The land had been used for utility operations and had been in rate base. She testified that since the ratepayers bear the risk of extraordinary losses incurred by the utility, they should likewise receive the benefit of extraordinary gains. She noted that this treatment would be consistent with the Commission's treatment of gains on sales or transfers of utility plant in prior natural gas, electric, and telephone cases.

During cross-examination, NCNG witness Teele revealed that the land in question had been purchased for less than $1,000, and that after the sale a new piece of land was purchased in a property "exchange" arrangement. The new land was placed in rate base at a substantially higher value than the original land that was sold for a gain.

The Commission concludes that the gain from this sale of land should be recorded in the deferred account over a period of three years to be returned to customers. Because NCNG is a regulated utility, its stockholders are insulated from extraordinary losses by the ability to seek amortization of such losses through rate increases. In other words, the risk of extraordinary capital losses is shifted from stockholders to ratepayers by virtue of the regulatory process. This is a different situation from the normal unregulated business where stockholders expect to receive extraordinary gains such as the appreciation in value of land, and they have a concomitant expectation that they will bear the risk of extraordinary losses.

The risks that investors of regulated utilities do bear are compensated for in the allowed rate of return set by the Commission; any additional return from extraordinary gains would amount to an improper windfall since the concomitant risk of extraordinary losses does not fall upon utility investors. Indeed, to allow the Company to keep the gain on sale in addition to the allowed return on equity would violate the North Carolina Supreme Court's holding that the history of G.S. 62-133(b)

> "supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States...."

State ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 377, 388, 206 S.E.2d 269 (1974).

The facts of the present case provide even stronger support for flowing the gain on sale to ratepayers than in past cases. The land exchange undertaken by NCNG had the effect of writing up rate base for the ratepayers. If NCNG had not sold the first piece of land, it would have remained in rate base at a very low figure, while the second piece of land for which the first tract was exchanged is now in rate base at a substantially higher figure. In these circumstances, the justification for ratepayers to receive the gain on sale is especially strong.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 192

The evidence supporting this finding of fact appears in the testimony of Public Staff witness Fernald and NCNG witness Teele. Ms. Fernald testified that the regulatory fee should be calculated on all jurisdictional revenues, including off-system sales to Public Service. On Workpaper C-7 Updated Revised, the Company included off-system sales in the regulatory fee calculation. Although these sales are "off-system," they have been reflected in pro forma revenues in this rate case. Therefore, the Commission concludes that off-system sales to Public Service should be included in the regulatory fee calculation.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 193

The evidence for this finding of fact is contained in the testimony of Public Staff witnesses Curtis and Hoard. Mr. Curtis recommended that NCNG true-up its lost and unaccounted for volumes annually based on the twelve-month running unaccounted for volumes at June 30 of each year. The imbalance should be placed in a deferred account. He testified that such a procedure would allow NCNG to recover only the actual volume difference between its supply and sales. Public Staff witness Hoard testified concerning the mechanism by which this true-up would be made. He recommended that a new section, Section 5, be added to Rider B (PGA Procedures), which provides for the pricing of the difference between the actual lost and unaccounted for volumes and the amount included in rates.

NCNG did not oppose such a true-up nor did any other party. The Commission concludes that a true-up as recommended by the Public Staff is reasonable and NCNG's lost and unaccounted for volumes should be trued-up on an annual basis in the manner set forth herein.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 194

The evidence for this finding of fact is contained in the testimony of Public Staff witness Curtis. Witness Curtis testified that at the time the Public Staff pre-filed its original testimony in this docket, CP&L expected to be burning natural gas at its Wheatherspoon plant in the near future. He was subsequently informed that during the last week of September the decision was made by CP&L not to invest the capital to install the filters needed to burn natural gas because these units were not expected to be run enough in the near future to justify the capital investment. Because this decision could change if CP&L's load grows more than expected or if another generating facility has to be shut down for unexpected reasons, witness Curtis recommended that NCNG be required to place any margins earned on sales of natural gas to CP&L for its Weatherspoon plant in the gas cost savings deferred account.

Unlike the off-system sales by NCNG which is discussed elsewhere herein, the Commission is not persuaded that the sale of gas to CP&L, if any, will occur in the foreseeable future. Accordingly, the Commission rejects the recommendation of the Public Staff in this regard.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 195 - 201

The evidence for these findings of fact is contained in the testimony and exhibits of NCNG witness Teele and Public Staff witness Curtis.

Witness Teele testified that the purpose of the revisions in the General Rules and Regulations is to streamline the rules, eliminate redundancies between certain of the company's rules and the Commission's rules, establish and set forth certain transportation procedures and guidelines in the General Rules rather than in each transportation tariff, address procedures regarding billing errors, and clarify responsibilities of the Company up to the point of delivery and of its customers beyond that point. Witness Teele presented Teele Exhibit 21, setting forth the proposed revisions.

Public Staff witness Curtis set forth in Curtis Exhibit L certain changes in NCNG's proposed General Rules and Regulations. During his rebuttal testimony NCNG witness Teele accepted many of the Public Staff's proposed changes and testified against certain others. Only a few differences remain.

Witness Curtis proposed to modify the first sentence of Section 3 to require a Commission approved service agreement with non-residential customers. Witness Teele testified that the Public Staff's proposal would be overburdensome to the Commission, the Company and the new customer. NCNG accepted the Public Staff's proposed modification to Section 3 that requires that NCNG not make any representations which conflict with its rate schedules or service regulations. The Commission believes that such language provides customers with sufficient protection and that it is not necessary to require specific Commission approval of service agreements before service can commence to new customers. There should be a standard service agreement form which should be submitted to the Commission for advance approval. However, special provisions may be added to the form based on the circumstances of particular customers, and such deviations need not be submitted for Commission approval. Disputes may be dealt with through the Commission's complaint jurisdiction.

Under NCNG's current Rules and Regulations, service agreements with residential and commercial customers may be verbal, controlled solely by the applicable tariff and the General Rules and Regulations. Witness Teele testified that such provisions should remain in Section 3 and that the Public Staff's suggestion to limit verbal agreements to residential customers should be rejected. The Commission agrees.

In order to effect the above decisions, the first sentence of the first paragraph of Section 3 shall be revised to begin, "Except as otherwise provided herein, the Company shall not be required to supply service unless and until Customer has made application to the Company for service and a written Service Agreement approved in form by the Commission has been executed by the Customer and the Company..." The first sentence of the second paragraph shall begin, "When the requested supply of gas is for residential service or commercial service, and no extra charges for additional facilities are involved, the Customer's application and the Company's acceptance may then be verbal..."

Witness Teele testified that the language proposed by NCNG in Section 23, dealing with responsibility beyond point of delivery, more clearly defines the

Company's responsibility than that set forth in Curtis Exhibit L. The Public Staff would revise the Section to delete the language concerning the Company's tort liability. The Commission agrees with the Public Staff and adopts its version of Section 23. NCNG's rules and regulations should not be used to define the Company's tort liability.

With respect to Section 15 of NCNG's proposed rules and regulations, the parties agreed on the change of the word "provide" to "extend its gas lines in order to provide". Witness Teele testified that the Company would not deny service to a customer already connected but wants the option to deny extending lines to serve a customer if his only use of gas is peak-shaving because such a low load factor situation would give the Company problems in recovering its investment.

Witness Teele was cross-examined at length by CUCA concerning sections of the proposed rules and regulations dealing with transportation customer imbalances. Witness Teele testified that a transportation customer can have either negative or positive imbalances when the volumes the customer had delivered to NCNG's system in a given month do not match the volumes used. Witness Teele testified to ways imbalances could be cured by the customer during the one month grace period following the month in which the imbalances occurred. Witness Teele testified that NCNG sends notices to transportation customers every month setting forth the status of their imbalance accounts and that NCNG maintains frequent telephone contact with these customers so that potential imbalance situations are not a surprise to the customer involved. Witness Teele testified that positive imbalances create problems for the Company in scheduling its gas purchases because customer gas may be loaded into NCNG's system when the price is low and then NCNG has to give it back to the customer when the price goes up. Witness Teele pointed out that, although a transportation customer's problems with its producer or the interstate pipelines may not directly be the customer's fault, the problems are not caused by NCNG. The procedures for gas cost adjustments prevent the shifting of the transportation customer's imbalance problems to NCNG and its remaining customers for more than the one month in which the transportation customer must correct the problem. Witness Teele testified that the last paragraph of the section on Gas Cost Adjustment of the Rules and Regulations is necessary to prevent the practice of customers buying large quantities of gas and having it delivered to NCNG's system in the summer months before October 31, for use during the winter period. Witness Teele testified that such practice adversely impacts NCNG's gas buying practices. The Commission concludes that these transportation imbalance provisions are reasonable and appropriate.

Except for the modifications found to be appropriate herein, NCNG's proposed service regulations as amended by the Public Staff and agreed to by the Company are just and reasonable.

IT IS, THEREFORE, ORDERED as follows:

1. That North Carolina Natural Gas Corporation is authorized to adjust its rates and charges effective for service rendered on and after the date of this Order so as to produce an annual level of revenue of $145,567,489 from its North Carolina retail customers (including revenues of $1,833,102 from firm sales to Public Service Company of North Carolina and $444,774 of other operating

revenues, and assuming a $2.5293 base cost of gas) based upon the adjusted test year level of operations found reasonable herein. This amount represents an increase of $2,564,512 more than would be produced from the rates in effect prior to this Order, based upon the test year level of operations.

2. That a connection fee of $15.00 for each new residential and commercial customer is approved effective for service rendered on and after the date of this Order.

3. That an increase in the returned check fee from $5.00 to $15.00 is approved effective for service rendered on and after the date of this order.

4. That increases in reconnection fees are approved as follows:

> For residential customers, the reconnection fee will increase from $19.42 to $29.13 in the months of February through August, and to $43.69 in the months of September through January.
>
> For commercial customers, the reconnection fee will increase from $29.13 to $38.84 in the months of February through August, and to $58.25 in the months of September through January.

The amounts stated above exclude the 3% North Carolina sales tax, and are to be effective for service rendered on and after the date of this Order.

5. That the Industrial Sales Tracker (IST) mechanism is approved as discussed herein and shall be effective for service rendered on and after the date of this Order. A revised IST Rider A consistent with the provisions of this Order including appropriate base period gross profits amounts shall be filed with the Commission not later than ten days after the date of this Order. The calculation of the appropriate base period gross profit amounts shall be subject to review by the Public Staff and final approval by the Commission.

6. That the Purchased Gas Adjustment (PGA) and deferred account procedures are approved as discussed herein, subject to modifications ordered by the Commission in Docket No. G-100, Sub 58, and shall be effective for service rendered on and after the date of this Order. A revised PGA Rider B consistent with the provisions of this Order shall be filed with this Commission not later than ten days after the date of this Order.

7. That the Weather Normalization Adjustment (WNA) mechanism is approved as discussed herein and shall be effective for service rendered on and after the date of this Order. A revised WNA Rider C consistent with the provisions of this Order shall be filed with this Commission not later than ten days after the date of this Order.

8. That changes to the General Rules and Regulations are approved as discussed herein and shall be effective for service rendered on and after the date of this Order. The Company shall file the revised General Rules and

Regulations as approved herein not later than ten days after the date of this Order.

9. That NCNG shall file written service agreement forms to be used for new customers. The forms shall be filed with the Commission within 60 days of the date of this Order and shall be deemed approved in the absence of written objections from a party to this proceeding within 60 days of the filing of such forms.

10. That within five (5) working days after the date of this Order, NCNG shall file tariffs with the Commission designed to produce the increase in revenues set forth in decretal paragraph number 1 above in accordance with the guidelines attached as Appendix A of this Order and such tariffs shall also be properly adjusted for all approved increments and decrements. The tariffs required herein shall be accompanied by computations showing the level of revenues which will be produced by the rates for each rate schedule. Upon the Company filing such tariffs, the Commission will allow two (2) days for intervenor comment.

11. That the tariffs prepared in accordance with decretal paragraph 10 above shall be submitted to the Commission for approval. Once approved, the rates shall be effective for service rendered on or after the date of this Order.

12. That the depreciation rates approved in Docket No. G-21, Sub 295, are those as more particularly set forth herein.

13. That NCNG shall notify its customers of the rates, charges, and Riders A, B, and C approved herein by appropriate bill insert in the next billing cycle. A copy of such proposed bill insert shall be filed with the Commission for approval.

14. That NCNG shall file a monthly report with the Commission showing the IST volumes sold and the gross profit earned compared to the base period IST monthly volumes and gross profit.

15. That NCNG shall apply an interest rate of 10%, compounded monthly, to its gas cost deferred account.

16. That NCNG shall prepare an accounting manual as recommended by the Public Staff within three years from the date of this Order.

17. That NCNG shall undertake a study to determine an appropriate methodology to properly allocate its employers' time spent on affiliated companies.

18. That NCNG prepare a square footage study during 1992 for the purpose of providing current data for allocating plant to non-utility operations.

19. That NCNG shall allocate on its books the expenses for payroll taxes, pension costs, group insurance, workers' compensation, accident and health, excess liability, and all other payroll related expenses to accounts based on the distribution of payroll, so as to properly record non-utility expenses in non-utility accounts, within 60 days of the date of this Order.

20. That NCNG shall record non-utility taxes in non-utility accounts within 60 days of the date of this Order.

21. That the gain on sale of $344,395 realized by NCNG from the sale of a tract of land in 1990, discussed herein, be grossed up for gross receipts tax and recorded in the gas cost deferred account to be flowed back over a period of three years to ratepayers.

22. That NCNG shall use as its Allowance for Funds Used During Construction (AFUDC) rate the overall return on investment approved in this Order.

23. That NCNG shall account for fuel retainage costs associated with storage injections as recommended by the Public Staff and discussed herein.

24. That the rate designs, rate schedules, miscellaneous charges, and terms and conditions proposed by the Company, except as modified herein, are approved.

ISSUED BY ORDER OF THE COMMISSION
This the 6th day of December, 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioner Tate concurs by separate opinion.

APPENDIX A
DOCKET NO. G-21, SUB 293
DOCKET NO. G-21, SUB 295

GUIDELINES FOR DESIGN OF RATE SCHEDULES

1. Rates shall be designed that produce the increase in revenues not exceeding the level of revenue approved in the Order.

2. Rate Schedules proposed by the Company as modified in this Order shall be used.

3. Demand charges and contract demand levels shall be as proposed by the Company except as modified in this Order.

4. Facilities charges and miscellaneous fees as approved elsewhere in the Order shall be used.

5. Rates in Rate Schedules 9 and T-5 are approved as filed by the Company.

6. Summer/winter differentials proposed by the Public Staff shall be used, except for Rate Schedules 9 and T-5.

7. Base cost of gas of $2.5293 per dekatherm shall be used.

8. Rates shall be designed that yield the following percent increases or decreases by customer class:

CUSTOMER CLASSES PER NCNG ORDER ADDENDUM E-1	REVENUE FROM RATES @10/1/91 PER NCNG ORDER ADDENDUM E-1	PERCENT CHANGE INCREASE/(DECEASE)
RESIDENTIAL	$29,145,323	7.4%
COMMERCIAL	$23,308,108	1.9%
INDUSTRIAL	$67,749,616	0.6%
MUNICIPALS	$20,614,298	2.57%

9. Percent increase or decrease by customer class may vary slightly, but must round to the percent shown in the table above to the decimal place indicated in the table.

10. Revenues for "Off-System" and "Misc." as show in Addendum E-1 to NCNG's Proposed Order shall be those in the column entitled "Proposed in Sub 293" in that Addendum.

NORTH CAROLINA NATURAL GAS CORPORATION
DOCKET NO. G-21, SUB 293
DOCKET NO. G-21, SUB 295

COMMISSIONER TATE, CONCURRING: It gives me concern that the stipulations entered in the recent Public Service and Piedmont general rate cases make it impossible to compare the overall regulatory treatment of North Carolina's natural gas companies. While each case is decided on the evidence presented, the Commission tries to make its adjustments consistent. For example, although all three cases were decided in 1991, the return on equity is higher for the two larger companies in the Piedmont than for the more sparsely populated NCNG. The stipulations specifically provided that the return on equity was not a precedent, but there is no way for a Commissioner to know what compromises were made on other issues to balance the return on equity given. I therefore am uncertain whether we have been evenhanded and fair with NCNG. Are the ratepayers treated equally in the three cases? I don't know and it makes me uneasy.

Commissioner Sarah Lindsay Tate

DOCKET NO. G-21, SUB 293

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for an Adjustment of Its Rates and Charges) ERRATA ORDER

BY THE COMMISSION: On December 6, 1991, the Commission issued its Order Granting Partial Rate Increase in this docket.

On December 18, 1991, NCNG filed Reply Comments and Suggested Corrections to the Order. By this filing, NCNG responded to certain comments and requests for reconsideration filed by other parties and pointed out certain errors in the language of the Commission's Order. The comments are being dealt with by separate Order issued this date. The present Errata Order is being issued to address the suggested corrections to the Commission's Order Granting Partial Rate Increase of December 6, 1991.

The Commission finds good cause to correct certain inadvertent misstatements as follows:

On page 15, in Finding of Fact No. 126, the phrase "$7.00 per Dt demand charge" should read "$8.50 per Dt demand charge."

On the third line from the bottom of page 90, the phrase "$7.00 per Dt demand charge" should read "$8.50 per Dt demand charge."

In paragraph 17 on page 119 (which NCNG cited as page 19), the term "employers' time" should read "employees' time."

In the table on page 121, the term "(DECEASE)" (which NCNG cited as "deceased") should read "(DECREASE)."

In the table on page 121, the number "2.57%" should read "(2.57%)."

On page 20, in Finding of Fact No. 176, the Commission states that $59,026 of gross receipts tax is allocable to the sale of natural gas to Public Service Company of North Carolina, Inc. No gross receipts tax was calculated on any of Public Service's revenues. The margin which should be included is not $1,204,984, but $1,264,010. This correction is necessary in order to state the margin correctly as the gross receipts tax does not apply to sales to Public Service. Also, on page 110, in the second stated conclusion, the gross receipts tax reference should be removed and the margin stated as $1,264,010.

On page 94, the fixed charge recovery rates proposed by the Public Staff and adopted by the Commission assume that all pipeline demand and storage charges are recovered by the commodity charge in NCNG's rates. This is not the case for Rate Schedules 9 (LOF), 10 (Fort Bragg), RE-2 and SM-1 (municipals), which contain Demand Charges which recover a substantial portion of pipeline demand and storage charges allocated to these rates. In order to avoid an overrecovery or underrecovery due to the variation of actual sales and transportation volumes from the volumes used in this proceeding, the fixed charge rate for these Rate Schedules should not include any costs that are recovered by the Demand Charge. The Commission concludes that these fixed charge rates should be as follows:

Rate Schedule	Per Order	Should Be
9	$.3508	$0.1208
10	.4321	-0-
RE-2	.5635	-0-
SM-1	.2933	-0-

IT IS, THEREFORE, ORDERED that the Order Granting Partial Rate Increase issued in this docket on December 6, 1991, should be corrected as hereinabove provided.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. G-21, SUB 293

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for an Adjustment of Its Rates and Charges) ORDER APPROVING TARIFFS IN PART

BY THE COMMISSION: On December 6, 1991, the Commission issued its Order Granting Partial Rate Increase in this docket. That Order approved a partial rate increase for North Carolina Natural Gas Corporation (NCNG), provided guidelines for rate design, and required NCNG to file tariffs designed to produce the revenue increase approved in accordance with the rate design guidelines. The Commission required that the tariffs be submitted to the Commission for approval and allowed time for intervenor comment.

On December 11, 1991, NCNG filed tariffs for approval as ordered by the Commission.

On December 13, 1991, the Public Staff filed Comments questioning the proposed rate design for Rate Schedules 4, 5 and 6.

The Public Works Commission of the City of Fayetteville (PWC) filed a Motion to Amend Order on December 13, 1991.

NCNG filed Reply Comments and Suggested Corrections to the Order on December 18, 1991.

The Motion of the PWC seeks reconsideration of certain Commission decisions herein. The Comments of the Public Staff question whether the rate design of the tariffs filed by NCNG on December 11, 1991, complies with the Commission's rate design guidelines as to Rate Schedules 4, 5 and 6. The Commission has taken both the Motion and the Comments under advisement. Pending our decision thereon, the Commission finds good cause to approve the rate design and tariffs filed by NCNG on December 11, 1991, as to all rate schedules except Rate Schedules 4, 5 and 6.

IT IS, THEREFORE, ORDERED that except as to Rate Schedules 4, 5 and 6, the rate design and tariffs filed by NCNG in this docket on December 11, 1991, should be, and the same hereby are, approved effective for service rendered on and after the date of the Order Granting Partial Rate Increase herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-21, SUB 293

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for an Adjustment of Its Rates and Charges) ORDER APPROVING BILL INSERT

BY THE COMMISSION: On December 6, 1991, the Commission issued its Order Granting Partial Rate Increase in this docket. That Order provided for NCNG to give notice to its customers by a bill insert which was to be approved by the Commission.

NCNG sent its proposed bill insert to the Commission on December 19, 1991, and the Commission finds good cause to approve it.

IT IS, THEREFORE, ORDERED that the proposed bill insert sent to the Commission on December 19, 1991, should be, and the same hereby is, approved.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. G-21, SUB 293

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of North Carolina Natural Gas Corporation for an Adjustment of Its Rates and Charges) ORDER APPROVING TARIFFS AND DENYING RECONSIDERATION

BY THE COMMISSION: On December 6, 1991, the Commission issued its Order Granting Partial Rate Increase in this docket. That Order approved a partial rate increase for North Carolina Natural Gas Corporation (NCNG), provided guidelines for rate design, and required NCNG to file tariffs designed to produce the approved revenue increase in accordance with the rate design guidelines. The Commission required that the tariffs be submitted to the Commission for approval and allowed two days for intervenor comment.

On December 11, 1991, NCNG filed tariffs for approval as ordered by the Commission.

On December 13, 1991, the Public Staff filed Comments questioning the proposed rate design for Rate Schedules 4, 5 and 6, and, in particular, the differential between the rates for IST customers and non-IST customers in those rate schedules.

On December 18, 1991, the Commission issued its Order Approving Tariffs in Part by which all rate schedules filed by NCNG except Rate Schedules 4, 5 and 6 were approved. The Commission took the Public Staff's comments as to Rate Schedules 4, 5 and 6 under advisement.

The Public Works Commission of the City of Fayetteville (PWC) filed a Motion to Amend Order on December 13, 1991. The PWC sought reconsideration of the Commission's denial of a separate electric generation rate schedule and reconsideration of the industrial rates approved by the Commission's Order Granting Partial Rate Increase.

On December 18, 1991, NCNG filed Reply Comments addressing the Comments of the Public Staff and the Motion of the PWC. Additionally, NCNG filed certain suggested corrections to the Commission's Order Granting Partial Rate Increase, which are being dealt with by separate Errata Order issued this date.

On December 19, 1991, the City of Monroe (Monroe) filed a letter with the Commission asserting that Rate Schedules RE-2 and T-6 as submitted by NCNG are not in compliance with the rate design guidelines of the Commission. Since those rate schedules had already been approved by the Commission's Order Approving Tariffs in Part on December 18, 1991, the Commission has treated Monroe's letter as a request for reconsideration.

On December 20, 1991, NCNG filed a letter responding to the letter of Monroe.

Additionally, on December 20, 1991, the Carolina Utility Customers Association, Inc. (CUCA), filed a Motion for Reconsideration addressing the rate design decisions of the Commission's Order Granting Partial Rate Increase.

Finally, on December 20, 1991, the Public Staff filed a Response dealing with its original comments on Rate Schedules 4, 5 and 6 and NCNG's reply thereto.

The Commission has carefully considered all of the comments and requests for reconsideration herein.

As to the issue of the IST premium and higher summer rates for IST customers related to Rate Schedules 4,5 and 6, NCNG asserts that it had not proposed to add the IST premium to the winter base rates of Rate Schedules 5B and 6B because of the present curtailment policy of curtailing on the basis of margin. NCNG also states that if the premium is applied in the winter, it would give IST customers a service advantage by allowing them to pay a higher rate than non-IST customers in order to gain a curtailment advantage. Further, NCNG points out that the concept of a premium is of practical value only when heavy oil prices rise sharply as, for example, during the international crisis of last winter and it does not believe that it should be put in the position of having to offer service to IST customers during the winter ahead of non-IST customers.

The Public Staff notes that NCNG's rates before the Order Granting Partial Rate Increase included a higher charge for IST customers compared to non-IST customers in Rate Schedules 5 and 6 and these higher rates have not caused a problem during the two years that curtailment by margin has been in effect. The Public Staff also points out that there is no precedent for this issue because previously there was no summer/winter differential in NCNG's rates.

The Commission notes that NCNG has designed rates with the IST premium applicable to summer service only consistent with its position in the general rate case. The Commission further is of the opinion that no compelling reasons have been set forth in the filings subsequent to the Order Granting Partial Rate Increase to cause the Commission to depart from such a methodology and that the application of a IST premium to summer rates only is not unreasonable for the reasons set forth by NCNG.

As to the Motion to Amend Order filed by the PWC, PWC states that the Commission's denial of PWC's request for a separate electric generation rate schedule is not supported by the record. Furthermore, PWC believes that the new rates for the industrial class which includes PWC are unfair and unduly discriminatory.

The Company, in its reply comments, responds that PWC is presently on NCNG's lowest tariff rates. In addition, a separate and lower electric generation rate is not needed since rates to PWC can be negotiated when necessary. Furthermore, the boiler fuel customer class which includes PWC is the only industrial customer class getting a rate decrease in this proceeding. The Company points out that the table filed by PWC in Exhibit A of their Motion to Amend shows how much PWC's gas bill will increase compared to NCNG's proposed rates and not compared to NCNG's present rates. PWC will, in fact, receive a rate reduction compared to present rates.

The Commission, citing a lack of both a concrete proposal and supporting evidence, declined to establish a separate rate class for electric utility customers. However, the Commission noted that Company witness Teele testified that the Company was willing to develop specific rate schedules similar to Rate Schedule 9 after discussions with the customer. After considering the record and PWC's arguments in the Motion to Amend Order, the Commission remains convinced that PWC did not adequately support the establishment of a separate rate schedule in this proceeding. PWC remains free to come forward with a proposal in NCNG's next general rate case.

As to PWC's objection to Finding of Fact No. 138, the Commission believes that the Commission Order adequately supports that Finding of Fact and that the rates for the industrial class are not unfair and unduly discriminatory.

As to the letter filed by the City of Monroe, Monroe objects to the Rate Schedule RE-2 and Rate Schedule T-6 contained in NCNG's compliance filing of December 11, 1991. Monroe contends that the rates filed are not in compliance with the Commission's Order. Appendix A of the Commission's Order, as corrected by the Errata Order issued by the Commission, required NCNG to reduce by 2.57% the revenue from municipal rate schedules as shown on Addendum E-1 of NCNG's proposed order under "Present Rates @ 10/01/91". Municipal rate schedules include RE-2, T-6 and SM-1. The tariffs filed by NCNG do yield the required 2.57% decrease in total revenue. However, Monroe objects to a shift of $21,875 in revenues from Rate Schedule T-6 to Rate Schedule RE-2 between the tariffs in the compliance filing and the rates in NCNG's proposed order as shown below:

	NCNG ORDER, TEELE EXH. 17 (REVISED UPDATED)		COMPLIANCE FILING	REVENUE DIFFERENCE
	PRESENT REVENUE	PROPOSED REVENUE	FILED TARIFFS	FILED LESS PROPOSED
RE-2	$12,622,618	$14,550,856	$14,572,731	$21,875
SM-1	3,983,940	3,983,940	3,983,940	--
T-6	4,007,740	1,550,444	1,528,570	(21,875)
TOTAL	$20,614,298	$20,085,240	$20,085,240	--

While Monroe acknowledges that the Commission Order also required NCNG to use the Public Staff's summer/winter differential, Monroe states that NCNG should have kept the proposed RE-2 rates that produced the $14,550,856 shown above and adjusted the T-6 rates.

The Company, in its December 20, 1991, letter responding to Monroe, states that the $21,875 shift results from the Commission's guidelines. The Commission agrees with the Company. The Commission Order required NCNG to design rates that produced a 2.57% decrease in total revenues from municipal customers. The Commission recognized that, in order to implement other guidelines, NCNG would have to make reasonable adjustments in the revenue collected under individual municipal rate schedules. The revenues generated by the rates in the Company's compliance filing fully conform with the Commission's guidelines.

Finally, as to the Motion for Reconsideration filed by CUCA, the Commission is not persuaded by CUCA's arguments. CUCA states, "One of the most significant issues before the Commission in this proceeding was the extent to which NCNG's rate design should be revised in order to more accurately reflect cost-of-service considerations." The Commission's Order discusses the factors that the Commission and the Court have held should be considered in setting rates. Cost-of-service studies are important guidelines, but they must be used in conjunction with the other factors. After careful consideration, the Commission declines to amend its Order.

For the reasons stated above, the Commission finds good cause to issue the present Order approving all of the rate design and tariffs filed in this docket by NCNG on December 11, 1991. Further, the Commission finds good cause to deny all of the requests for reconsideration filed herein.

IT IS, THEREFORE, ORDERED as follows:

1. That the rate design and tariffs filed by NCNG in this docket on December 11, 1991, should be, and the same hereby are, approved effective for service rendered on and after the date of the Order Granting Partial Rate Increase herein and

2. That the various comments and requests for reconsideration filed by the Public Staff, PWC, the City of Monroe, and CUCA should be, and the same hereby are, denied.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. T-2876, SUB 2

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Hilco Transport, Inc., 1024 East Mountain Street, Kernersville, North Carolina 27284 Application for Common Carrier Authority	ORDER OF REMAND FOR FURTHER EVIDENCE

ORAL ARGUMENT
HEARD IN: Commission Hearing Room 2115, 430 North Salisbury Street, Raleigh, North Carolina, on August 29, 1991, at 11:00 a.m.

BEFORE: Chairman William W. Redman, Jr., Presiding; and Commissioners Sarah Lindsay Tate, Robert O. Wells, Charles H. Hughes, and Allyson K. Duncan

APPEARANCES:

For the Applicant:

Robert W. Kaylor, Patterson, Dilthey, Clay, Cranfill, Sumner & Hartzog, Attorneys at Law, Post Office Box 310, Raleigh, North Carolina 27602
For: Hilco Transport, Inc.

For the Protestants:

Ralph McDonald, Bailey & Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605
For: Eagle Transport Corporation and A. C. Widenhouse, Inc.

BY THE COMMISSION: On July 2, 1991, Commission Hearing Examiner Barbara A. Sharpe entered a Recommended Order in this docket denying the application of Hilco Transport, Inc. (Hilco or Applicant), for common carrier operating authority, but granting Hilco additional contract carrier authority as follows:

"Transportation of Group 21, asphalt and asphalt cutback, in bulk, statewide, under contract with Barrus Construction Company."

On July 17, 1991, the Applicant filed an exception to the Recommended Order and requested the Commission to schedule an oral argument to consider that exception.

The Commission granted the Applicant's request for oral argument. The oral argument thereafter was called to order at the appointed time and place before the Full Commission. Counsel for the Applicant and the Protestants offered oral argument on the exception. The Applicant requested the Commission to take judicial notice of Docket No. T-2876, Sub 3, which involves an application for additional contract carrier operating authority filed on May 17, 1991, and grant the requested common carrier operating authority in this docket on the basis of the combined records. In the alternative, the Applicant requested the Commission to remand the matter for further evidence.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission finds good cause to grant the Applicant's alternative request and remand this case for further evidence. In so deciding, the Commission notes that at the conclusion of the hearing held before Hearing Examiner Sharpe on May 7, 1991, the Applicant requested the opportunity to take the testimony of Mr. Ray Phaff of Barnhill Contractors through deposition for incorporation into the record of this case. Counsel for the Applicant indicated that Mr. Phaff had been scheduled to testify on behalf of Hilco, but was unable to do so because he was ill with the flu. The Protestants objected and the motion was denied by the Hearing Examiner.

The Commission concludes that the Applicant should be allowed to introduce Mr. Phaff's testimony as well as any other relevant evidence on remand. Such evidence will, of course, be in addition to the record already compiled. During the remand hearing, it would be appropriate for the Applicant to renew its request for judicial notice of Docket No. T-2876, Sub 3. The Hearing Examiner will then rule upon that motion.

IT IS, THEREFORE, ORDERED that this docket be, and the same is hereby, remanded for further hearing which shall be held on Tuesday, October 15, 1991, at 9:30 a.m. in Commission Hearing Room 2160, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of September 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioners Wright and Cobb did not participate in this decision.
Commissioner Duncan concurs.
Commissioner Hughes joins in Commissioner Duncan's concurring opinion.

COMMISSIONER DUNCAN CONCURRING

I concur in the decision to remand this case, and write separately only to set out my interpretation of the nature of the proof required. Rule R2-15(b) provides that "[i]f the application is for a permit to operate as a contract carrier of property or passengers, proof of a public demand and need for the service is not required; however, <u>proof is required that one or more shippers or passengers</u> have a need for a specific type of service not otherwise available by existing means of transportation and have entered into and filed with the Commission. . .a written contract with the application for said service. . ." (emphasis added). R2-15(b) thus appears to contemplate a showing, by testimony or otherwise, that certain shippers have a special need for the applicant's services.

Rule R2-15(a), on the other hand, which governs application for the common carrier authority sought here, does not contain a similar requirement. It provides that ". . .the applicant shall establish by proof (i) that a public demand and need exists for the proposed service in addition to existing authorized service, (ii) that the applicant is fit, willing and above to properly perform the proposed service, and (iii) that the applicant is solvent and financially able to furnish adequate service on a continuing basis." Unlike 15(b), 15(a) places no limits on the form the proof may take. Evidence that, for example, there are a hundred shippers subject to state and federal requirements to use minority contractors, and no certified disadvantaged business enterprises eligible to receive such contracts, would certainly seem to be probative on the question of public demand and need--the only criterion the hearing examiner found was not met in this case.

Such statistical evidence has been found to be sufficient to make out a prima facie case in other areas of the law. See, for example, Teamsters v United Sates, 431 U.S. 324 (1977). There is not apparent reason that it should not be equally probative here.

Allyson K. Duncan

Commissioner Hughes joins in concurring opinion.

Charles H. Hughes

DOCKET NO. T-3432

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Bunch's, Inc., 700 John Small Avenue, Washington, North Carolina 27889 - Application for Common Carrier Authority	)))	FINAL ORDER RULING ON EXCEPTIONS AND GRANTING APPLICATION IN PART

ORAL ARGUMENT HEARD IN: Commission Hearing Room 215, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina on Thursday, April 11, 1991, at 9:30 a.m.

BEFORE: Chairman William W. Redman, Jr., Presiding; and Commissioners Sarah Lindsay Tate, Robert O. Wells, Julius A. Wright, Charles H. Hughes, and Laurence A. Cobb

APPEARANCES:

For the Applicant:

Ralph McDonald, Bailey & Dixon, Attorneys at Law, Post Office Box 12865, Raleigh, North Carolina 27605
For: Bunch's, Inc.

For the Protestants:

Theordore C. Brown, Jr., Attorney at Law, Post Office Box 12547, Raleigh, North Carolina 27605
For: ABC Moving & Storage Company, Inc., and Airway Moving & Storage Company, Inc.

BY THE COMMISSION: On November 20, 1990, Bunch's, Inc. (Applicant), filed an application with the Commission for common carrier authority to transport Group 1, general commodities (except commodities in bulk in tank vehicles and unmanufactured tobacco), and Group 18, household goods, statewide.

The Commission Calendar of Hearings dated November 29, 1990, set the application for hearing on January 16, 1991.

A joint protest and petition to intervene was filed on December 7, 1990, on behalf of ABC Moving & Storage Company, Inc. (ABC), and Airway Moving & Storage Company, Inc. (Airway). By Order dated December 11, 1990, Protestants were allowed to intervene in this proceeding.

By Orders dated January 2, and January 25, 1991, the hearing was rescheduled to this time and place.

Upon call of the matter for hearing, Applicant and Protestants were present and represented by counsel. The Hearing Examiner was Barbara A. Sharpe. Prior to the presentation of evidence, Protestants limited their opposition to the household goods portion of the application. Applicant's request to present affidavits by shippers in support of the general commodities portion of the application after the hearing was allowed.

Applicant offered the testimony of Donald D. Bunch, Applicant's President, and public witnesses James V. Boyer, Hugh Todd, Jr., Jean DuVall, Dolly Brantley, George Douglas Thigpen, Phyllis R. Hendrickson, Eugene King, Judy B. Berry, and Thomas E. Strickland, Jr., in support of the household goods portion of the application.

Protestants then offered in opposition to the household goods portion of the application the testimony of T. Donald Taylor, Vice President of ABC, and Von Fodrie, President of Airway.

On March 20, 1991, Hearing Examiner Sharpe entered a Recommended Order in this docket granting the Group 1 authority to transport general commodities requested by the Applicant, but denying the authority to transport Group 18, household goods.

On March 25, 1991, the Applicant filed certain exceptions to the Recommended Order and requested the Commission to schedule an oral argument to consider those exceptions.

The matter was subsequently scheduled for oral argument on exceptions by Order dated March 26, 1991. The oral argument was held before the Commission on Thursday, April 11, 1991, at 9:30 a.m. The Applicant and Protestants both offered oral argument through counsel.

Based upon a careful consideration of the testimony and evidence presented at the hearing, the documents and exhibits received in evidence and judicially noticed, the sworn affidavits of shippers in support of the general commodities portion of the application, the oral argument on exceptions, and the entire record in this proceeding, the Commission now makes the following

FINDINGS OF FACT

1. The Applicant seeks common carrier authority to transport Group 1, general commodities (except commodities in bulk in tank vehicles and unmanufactured tobacco), and Group 18, household goods, statewide.

2. Applicant is a North Carolina corporation chartered on January 31, 1991. The stock is owned by Donald D. Bunch and wife, Linda H. Bunch.

3. Mr. Bunch owns Bunch's Piano Shop which he has operated for approximately 15 years as a piano rebuilding business in Washington.

4. Applicant's officers and employees have considerable experience in the transportation and repair of pianos. In addition to Mr. and Mrs. Bunch, Applicant has four full-time employees, all of whom have worked for the Applicant for at least two years.

5. Applicant holds an exemption certificate from the Division of Motor Vehicles and conducts for-hire operations involving movements of furniture and household goods in the Washington commercial zone.

6. Applicant testified that he has performed several movements of household goods outside the Washington commercial zone in the past but was unaware at the time that authority from the Utilities Commission was required to perform this transportation. The application was filed with the Commission upon learning that operating authority was required for these moves.

7. Bunch's Piano Shop has two vehicles suitable for the transportation of household goods and general commodities. This equipment may be transferred to the Applicant along with sufficient assets from the owners with which to capitalize the transportation operations and to acquire rolling equipment as necessary to provide adequate and continuing service to the public.

8. The general commodities portion of the application is unopposed, and Applicant has submitted affidavits from three shippers: Judy B. Berry, owner of Judy's Gift Baskets; William Russell Wiley, President of Wiley Lumber Company; and Rick O. Stevens, President of Moss Building Supply Company. These shippers have a need for the transportation of general commodities from Washington to points in the State and from points in the State back to Washington.

9. James Vaughn Boyer operates a landscaping business, a retail store, and a mini-storage facility in Washington. Several years ago, Mr. Boyer personally moved his household goods from Raleigh to storage in Washington. Applicant then moved the furnishings from storage to Mr. Boyer's new home in Washington and did a good job. In Mr. Boyer's opinion, there is a need for another authorized carrier of household goods in the Washington area.

10. Hugh Todd, Jr., has moved his household furnishings more than 10 times in intrastate and interstate commerce. Intrastate moves have included Rocky Mount to Washington and Charlotte to Rocky Mount. Mr. Todd has never had his furniture moved by a commercial carrier without damage, and in some cases excessive damage. On his most recent move from Rocky Mount to Washington, Mr.

Todd moved his own furnishings because he did not trust commercial carriers. Applicant sold and delivered a 100-year old antique piano to Mr. Todd and did an excellent job. Mr. Todd has encountered other problems with commercial carriers including trucks arriving late, trucks not being big enough, late deliveries, inexperienced labor, and laborers who appeared to possibly have been drinking. Mr. Todd is building a house in a development outside the Washington commercial zone and would like to have Applicant available to move his furnishings when the house is completed.

11. Jean DuVall moved her household furnishings from Winterville in Pitt County to Washington approximately three years ago. Ms DuVall used ABC for her move from Winterville to Washington and was thoroughly dissatisfied with ABC's services because of damages to her furnishings and rude and disrespectful ABC employees. In Ms. DuVall's opinion there is a need for another authorized carrier of household goods in the Pitt/Beaufort County area. Ms. DuVall plans to build a new home in a development outside Washington and would like to have Applicant available to move her furnishings when the house is completed. Ms. DuVall will not use ABC if the Applicant is not available.

12. Dolly Brantley, a resident of Washington, has purchased a piano from the Applicant and also has used Applicant for an in-house remodeling move. The service provided by Applicant was excellent in both cases. In Ms. Brantley's opinion, there is a need for another authorized carrier of household goods in the Washington area.

13. George Douglas Thigpen is Superintendent of the Washington City Schools. As Superintendent of City Schools, Mr. Thigpen has need to contract for moving services from time to time. Mr. Thigpen has used Applicant to move and store pianos for the school system, and he has used the Applicant to repair and tune his personal grand piano. Applicant's service has been good. In Mr. Thigpen's opinion, there is a need for another authorized carrier of household goods in the Washington area in order to stimulate competition and enhance service by the carriers. Mr. Thigpen has moved his personal furnishings twice by for-hire carriers. On one move from Clinton in Sampson County to Washington, there was a problem with damages to his property.

14. Phyllis R. Hendrickson has used Applicant to move her household furnishings from Washington to a townhouse five to seven miles outside of town. The service provided was excellent. She has plans to build a new house this year three to four miles from her present address and would like to use the services of the Applicant for the move. In Ms. Hendrickson's opinion, there is a need for another authorized carrier of household goods to serve the community.

15. Eugene King is Advertising Director of the Washington Daily News. He used Applicant to move his furnishings from outside Washington into town, approximately one mile, and was very satisfied with the services. Applicant advertises in the Washington Daily News. Neither ABC nor Airway does. In Mr. King's opinion, there is a need for another Washington-based carrier of household goods in the Washington area.

16. Judy B. Berry operates Judy's Gift Baskets in Washington and is also Community Service Coordinator for Beaufort County for the Department of Crime Control and Public Safety. Ms. Berry has used Applicant to move pianos and has

received excellent service. In Ms. Berry's opinion, there is a need for another authorized carrier of household goods in the Washington and Beaufort County area.

17. Thomas E. Strickland is a senior buyer for National Spinning Company in Washington and resides in Hubert, North Carolina. Mr. Strickland has moved his furnishings from the central part of North Carolina to Washington, between Whiteville in Columbus County and Washington and from Washington to Hubert in Onslow County. Mr. Strickland used ABC for three of his moves because his company paid for the movements and selected the carrier. The service was satisfactory except on the second move from Washington to Whiteville when a dining room table was damaged and adequate compensation was not paid. Applicant purchased Mr. Strickland's house in Washington and moved Mr. Strickland's furnishings to Hubert as part of the transaction. The service provided by Applicant was excellent. In Mr. Strickland's opinion, there is a need for another authorized carrier of household goods in the areas of North Carolina where he has lived.

18. ABC has been in business since 1949 and holds Certificate No. C-676 which authorizes statewide transportation of household goods. Mr. Taylor testified that his company is located in Greenville but has a small warehouse and one full-time employee who solicits business in Washington. He also testified that ABC has idle equipment and that the granting of this application would impair his present operations.

19. Airway holds statewide household goods authority in Certificate No. C-618 and has been in business since 1951. Mr. Fodrie testified that Airway has not actively solicited business in Beaufort County in the last two years because the volume of business did not justify keeping an advertisement in the local yellow pages and a local telephone number. He also testified that his company has idle equipment and that the granting of this application could impair his present operations.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

This application for a common carrier certificate is governed by G.S. 62-262(e) which imposes upon the Applicant the burden of proving the following to the satisfaction of this Commission:

1. That public convenience and necessity require the proposed service in addition to existing authorized transportation services; and

2. That Applicant is fit, willing, and able to properly perform the proposed service; and

3. That Applicant is solvent and financially able to furnish adequate service on a continuing basis.

The evidence in this record on the second statutory criterion is not conflicting. The Applicant has operated Bunch's Piano Shop for 15 years and is experienced in transporting pianos in conjunction with his business. The two vehicles owned by Bunch's Piano Shop are suitable for the transportation of household goods and general commodities and will be available for use by the Applicant. Also, the Applicant has transported household goods in the Washington commercial zone under an exemption certificate issued by the Division of Motor Vehicles. Prior to obtaining this exemption certificate, Applicant testified to performing several illegal moves which were performed out of ignorance rather than willful acts to evade the regulations. This Commission is permitted, but not compelled, to find that Applicant's unlawful operations renders it unfit to serve as a common carrier. In light of the record as a whole, however, the Commission concludes that Applicant is fit, willing, and able to properly perform the proposed common carrier services.

The third statutory criterion pertains to the Applicant's solvency and financial ability to furnish service on a continuing basis. The owners have sufficient assets with which to capitalize the transportation operations and to acquire rolling equipment as necessary to provide adequate service.

The Commission concludes that Applicant is solvent and financially able to furnish adequate service on a continuing basis.

Consideration of the first statutory criterion requires definition of "public convenience and necessity." Utilities Commission v. Queen City Coach Co., 4 N.C. App. 116, 123 and 124, and 166 S.E.2d 441 (1969), defined the phrase as follows:

> "(1) Our Supreme Court has said many times that what constitutes 'public convenience and necessity' is primarily an administrative question with a number of imponderables to be taken into consideration, e.g., whether there is a substantial public need for the service, whether the existing carriers can reasonably meet this need, and whether it would endanger or impair the operations of existing carriers contrary to the public interest. Utilities Commission v. Trucking Co., 223 N.C. 687, 28 S.E.2d 201; Utilities Commission v. Ray, 236 N.C. 692, 73 S.E.2d 870; Utilities Commission v. Coach Co., and Utilities Commission v. Greyhound Corp., 260 N.C. 43, 132 S.E.2d 249.
>
> "(2) We are not inadvertent to the fact that the factors denominated as imponderables, to wit: whether the existing carriers can reasonably meet the need for the service and whether the granting of the application would endanger or impair the operations of existing carriers contrary to the public interest, are not solely determinative of the right of the Commission to grant the application. Both are directed to the question of public convenience and necessity. Utilities Commission v. Coach Co., 233 N.C. 119, 63 S.E.2d 113. Nevertheless, if the proposed operation under the certificate sought would seriously endanger or impair the operations of existing carriers contrary to the public interest, the certificate should not be issued. Utilities Commission v. Coach Co., supra."

The evidence under the first statutory criterion, public convenience and necessity, does not establish a substantial public need for the transportation services proposed by the Applicant on a statewide basis. The evidence does, however, support a grant of limited authority to the Applicant to transport general commodities and household goods from Beaufort County to points in North Carolina and from points in North Carolina to Beaufort County. The Applicant, who currently provides moving services within the Washington commercial zone pursuant to an exemption certificate, has demonstrated a public demand and need for the services authorized by this Order. The public witnesses testified that there is a need for additional carriers to provide enhanced service and more competition in the Washington and Beaufort County area. Only one of the Protestants, ABC, operates regularly in the Washington area. There is no compelling evidence in the record to substantiate a finding that the service authorized by this Order would have a ruinous competitive effect upon other authorized carriers contrary to the public interest.

IT IS, THEREFORE, ORDERED as follows:

1. That the application of Bunch's, Inc., for a certificate of public convenience and necessity be, and the same is hereby, granted in part in accordance with Exhibit B attached hereto and made a part hereof.

2. That Bunch's, Inc., shall file with the North Carolina Division of Motor Vehicles, Motor Carrier Safety Regulation Unit, evidence of the required liability and cargo insurance, list of equipment, designation of process agent, and shall also file with the Commission Transportation Rates Division, a tariff of rates and charges and otherwise comply with the rules and regulations of the Commission.

3. That unless the Applicant complies with the requirements set forth in Ordering Paragraph 2 and begins operating as herein authorized within 30 days after the date of this Order, unless such time is extended in writing by the Commission upon request for such extension, the operating authority granted herein shall cease.

4. That the Applicant shall maintain its books and records in such a manner that all of the applicable items of information required in the prescribed annual report to the Commission can be used by the Applicant in the preparation of such annual report. A copy of the annual report form shall be furnished upon request to the Transportation Rates Division, Public Staff, North Carolina Utilities Commission.

5. That this Order shall constitute a certificate until a formal certificate has been issued and transmitted to the Applicant authorizing the common carrier transportation services described and set forth in Exhibit B attached hereto.

6. That the Applicant's exemption certificate shall be cancelled upon the Applicant's compliance with the filing requirements set forth in Ordering Paragraph 2.

7. That the exceptions to the Recommended Order filed in this docket by the Applicant be, and the same are hereby, allowed in part.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of April 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

Commissioner Ruth E. Cook did not participate in the decision in this case.

DOCKET NO. T-3432

BUNCH'S, INC.
700 John Small Avenue
Washington, North Carolina 27889

EXHIBIT B

IRREGULAR-ROUTE COMMON CARRIER AUTHORITY

Transportation of Group 1, general commodities, (except commodities in bulk in tank vehicles and unmanufactured tobacco), and Group 18, household goods, from Beaufort County to points in North Carolina and from points in North Carolina to Beaufort County.

DOCKET NO. P-89, SUB 41

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of AccuTek Computers, 1416 S. Stratford Road, Winston-Salem, North Carolina 27103, Complainant vs. Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company, Respondents	ORDER CONTINUING RESTRAINING ORDER PENDING HEARING AND DECISION; ORDER SCHEDULING HEARING ON COMPLAINT ON FEBRUARY 13, 1991

BY THE COMMISSION: On December 12, 1990, the Commission issued an Order serving the complaint of AccuTek Computers on Southern Bell Telephone and Telegraph Company ("Southern Bell") and BellSouth Advertising and Publishing Company ("BAPCO"). The Order also temporarily restrained Southern Bell and BAPCO from the collection of the $704.23 outstanding charge, "by disconnection of the telephone service of the Complainant or otherwise, pending Southern Bell's and BAPCO's response on the issue of the continuation pendente lite of the Temporary Restraining Order and Commission ruling thereon. BAPCO and Southern Bell shall have ten (10) days after receipt of this Order to respond to the Complainant's request for a restraining order pendente lite."

On December 21, 1990, the Commission issued a further order granting an extension of time to and including January 2, 1991, in which BAPCO and Southern Bell could file responses on the issue of the continuation of the Temporary Restraining Order granted on December 12, 1990. This Order also served Southern Bell and BAPCO with the resubmitted complaint to which was attached a notarized statement of the Complainant.

On December 28, 1990, Southern Bell filed its Answer in this docket, requesting that the complaint be dismissed as to Southern Bell because Southern Bell has addressed the Complainant's concerns regarding disconnection of its telephone service for failure to pay the disputed advertising charges in question. In its Answer, Southern Bell stated that it is the policy of the Company not to disconnect telephone service because of a customer's failure to pay charges owed BAPCO. In the AccuTek case, Southern Bell took action to remove the disputed BAPCO directory charges from Southern Bell's billing system and referred those charges to BAPCO. Southern Bell notified the Complainant of this action by a letter dated November 19, 1990. The letter also pointed out that further collection action may be taken by BAPCO. In conclusion, Southern Bell stated that as a result of its action in removing the directory advertising charges in question from its billing records, AccuTek's telephone service will not be interrupted for failure of Complainant to pay the BAPCO charges in dispute.

On January 3, 1991, BAPCO filed Motion to Dissolve Temporary Restraining Order and Dismiss the Complaint. In its Motion to Dissolve Temporary Restraining Order ("TRO"), BAPCO alleged that the Commission has no authority to issue temporary restraining orders or injunctions; that the Temporary Restraining Order must be dissolved for failure of the Commission to comply with the requirements of Rule 65(b) of the North Carolina Rules of Civil Procedure, including issuance of the TRO without a verified complaint or supporting affidavits, issuance of the TRO without the required endorsement of the date and hour of issuance, issuance of the TRO without defining the nature of the injury or why the Complainant will suffer irreparable harm, and failure of the TRO to expire of its own terms within ten days. BAPCO further alleged that the Commission failed to order and failed to consider that the Complainant must post a bond as a condition for the issuance of a TRO, as required by Rule 65(c). In conclusion, BAPCO alleged that the Commission's entire process of issuing a TRO without notice violates BAPCO's rights to due process of law under the United States and North Carolina Constitutions.

In its Motion to Dismiss Complaint, BAPCO alleged that AccuTek complains of a purported omission of AccuTek's cross reference listing in the white pages of the 1990-91 Winston-Salem directory and that this was a matter governed by the tariffs of Southern Bell, General Subscriber Service Tariff Section A2.5.1 and A6.7.6A. "There is no error in Complainant's yellow pages advertising nor any allegation of error by Complainant." Further, BAPCO asserted that the terms and conditions for BAPCO's publishing of yellow pages advertising from the Complainant is a matter of private written contract and that the Commission does not have the constitutional or statutory authority to adjudicate such contractual matters.

On January 4, 1991, the Attorney General filed Attorney General's Reply to Both BAPCO's Motion to Dissolve Temporary Restraining Order and Southern Bell's Motion to Dismiss. In its reply, the Attorney General took issue with the assertions of BAPCO and Southern Bell in their pleadings and requested the Commission to deny both BAPCO's and Bell's Motions to Dismiss and BAPCO's Motion to Dissolve the Restraining Order.

Continuation of the Restraining Order Pending Hearing and Decision

Upon consideration of the above-described pleadings of Southern Bell, BAPCO, and the Attorney General, the Commission is of the opinion, and so concludes, that the Restraining Order entered in this docket on December 12, 1990, and extended by Order of December 21, 1990, should be continued as to BAPCO pending hearing on the complaint and decision in this docket.

In so deciding, the Commission addresses the issues raised and discussed by the parties in their pleadings. With respect to the authority of the Commission to issue restraining orders, the Commission concludes that it has authority to issue such restraining orders pursuant to G. S. 62-73 and G. S. 62-30. G. S. 62-73 authorizes the Commission to hear complaints against public utilities, including complaints against BAPCO with respect to yellow pages disputes such as the one before us in the instant docket. Utilities Commission v. Southern Bell, 326 N.C. 522 (1990) (The "Boulevard Florist" case). G. S. 62-30 gives the Commission such general power and authority to supervise and control the public utilities of the State as may be necessary to carry out the laws providing for their regulation, "and all such other powers and duties as may be necessary or incident to the proper discharge of its duties." As pointed out by the Attorney General in its reply, the Commission has issued restraining orders in a number restraining orders in a number of cases, including complaint cases arising out of utility disputes. This necessary or incidental power allows the Commission to preserve the status quo between the parties in dispute pending hearing and decision on a complaint; otherwise, the complainant may be irreparably harmed if the utility were allowed to continue the activity complained of while the Commission undertakes hearing and decision on the complaint.

As pointed out by BAPCO in its Motion to Dissolve, the Commission's Temporary Restraining Order in this docket did not precisely follow all of the procedural steps set forth in Rule of Civil Procedure 65(b). The Commission's restraining order was temporary in nature, and BAPCO and Southern Bell were allowed ten days, later extended to January 2, 1991, to respond to the issue of the continuance of the Restraining Order pendente lite. It is true that the original complaint upon which the Temporary Restraining Order was issued was not verified. The Complainant later submitted a complaint which was sworn to as true, and this resubmitted complaint was served upon BAPCO and Southern Bell by Order of December 21, 1990. We believe that the notarized resubmitted complaint cured any defect which was in the original complaint. With respect to the other matters contended by BAPCO that constituted noncompliance with Rule 65, the Commission points out it has been generally recognized by the courts that procedure before the Commission is more or less informal and is not generally subject to the same degree of strictness as is required in the Superior Courts of the State. Utilities Commission v. Carolinas Committee for Industrial Power Rates, 257 N.C. 560 (1962). Substance and not form is controlling in proceedings before the Commission. Utilities Commission v. Western Carolina Telephone Company, 260 N.C. 369 (1963).

As stated in the Commission's Order of December 12, 1990, the Commission was of the opinion that unless a temporary restraining order was issued enjoining the collection of the disputed account by disconnection of telephone service or otherwise, there would be immediate and irreparable injury to the Complainant, a business enterprise which faced the possible loss of telephone service to its business. The Commission's Orders of December 12 and 21 gave the Respondents until January 2, 1991, to address the continuation of the restraining order pendente lite. If the Respondents had wished to be heard on this matter earlier, they could have requested a hearing before the Commission. (The extension of time to respond until January 2, 1991, was at the request of BAPCO, which had advised the Commission that it was attempting to negotiate a settlement of the dispute with the Complainant.) Although the Commission's procedure in issuing the temporary restraining order lacked many of the formal elements of Rule 65, the Commission is satisfied that its Order substantially complied with the spirit of Rule 65 and protected the rights of all of the parties in this proceeding.

Southern Bell has assured the Commission in its Response that as a result of its practices, the amount in dispute with BAPCO would not subject the Complainant to disconnection of telephone service by Southern Bell. Therefore, the Restraining Order as to Southern Bell will be dissolved. The Commission is of the opinion, and so concludes, that the Restraining Order as to BAPCO should be continued pendente lite in order to afford the Commission an opportunity to hear and decide the complaint in this docket. The Commission finds that the Complainant would be irreparably harmed if BAPCO were allowed to initiate collection proceedings on the yellow pages advertising in dispute pendente lite, in that the Complainant's credit rating and business reputation could be adversely affected by such collection action. The Commission has scheduled a hearing in this matter on February 13, 1991, in order to resolve the complaint in an expeditious manner. Accordingly, the Commission issues this Order restraining BAPCO from attempting the collection of the amounts in dispute pending the Commission's hearing and decision on the complaint.

Motions to Dismiss

The Commission concludes that the Motions of BAPCO and Southern Bell to dismiss the complaint should be denied. The allegations of the complaint, which spoke to the problems of Complainant arising out of its not being listed in both the white and the yellow pages of the 1990-91 Winston-Salem directory, are sufficient to require the inclusion of both parties in this proceeding.

IT IS, THEREFORE, ORDERED as follows:

1. That the Restraining Order issued in this docket on December 12, 1990, and extended to January 2, 1991, by Order of December 21, 1990, be continued in force and effect as to BAPCO pending hearing and decision on the complaint of AccuTek Computers. BAPCO shall be specifically restrained and enjoined from attempting to collect the amount of yellow page charges disputed by AccuTek in its complaint, either by instituting collection proceedings or by causing telephone service to be disconnected to the business of AccuTek or by any other means, pending hearing and decision on the complaint by the Commission.

2. That the Motions to Dismiss of Southern Bell and BAPCO be denied. The Respondents may file answer, or further answer, in this docket on or before February 8, 1991.

3. That a hearing be scheduled on the complaint in this docket at the following time and place:

Wednesday, February 13, 1991, at 9:30 a.m.,
Hearing Room 2115, Dobbs Building, 430 North
Salisbury Street, Raleigh, North Carolina

ISSUED BY ORDER OF THE COMMISSION.
This the 9th day of January 1991.

NORTH CAROLINA UTILITIES COMMISSION
Sandra J. Webster, Chief Clerk

(SEAL)

DOCKET NO. P-12, SUB 89

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application of Citizens Telephone Company for Authority to Adjust its Rates and Charges for Intrastate Telephone Service	)))	ORDER GRANTING PARTIAL RATE INCREASE

HEARD IN: Transylvania County Courthouse, Brevard, North Carolina, on Monday, December 10, 1990

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, December 12, 1990

BEFORE: Commissioner Laurence A. Cobb, Presiding, and Commissioners Robert O. Wells and Julius A. Wright

APPEARANCES:

For the Applicant:

F. Kent Burns and Daniel C. Higgins, Burns, Day & Presnell, P.A., Post Office Box 10867, Raleigh, North Carolina 27605

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

Karen E. Long, Assistant Attorney General, N. C. Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602

Richard Griffin, Assistant Attorney General, N. C. Department of Justice, 11 North Market Street, Asheville, North Carolina 28801

BY THE COMMISSION: This matter was initiated on July 6, 1990, with the filing of an application by Citizens Telephone Company (Applicant, Company or Citizens) seeking authority to adjust its rates and charges for telephone service in North Carolina. On July 20, 1990, the Public Staff filed a Motion with the Commission requesting that the Commission notify Citizens that its application was incomplete. On July 20, 1990, the Commission sent a letter to Citizens advising the Company that its application was incomplete and requesting that a corrected application be filed within five days. On July 26, 1990, Citizens filed a corrected application proposing to make its requested rate adjustments effective August 26, 1990.

By Order issued August 15, 1990, the Commission declared the matter to be a general rate case pursuant to G.S. 62-137, suspended the proposed rates and charges for up to 270 days from August 26, 1990, set hearings to begin December 10, 1990, declared the test period to be the twelve months ended December 31, 1989, required the Company to give public notice of the proposed increase and hearings at its own expense, and set the time for the Public Staff and other interested parties to file interventions and testimony. Public Hearings were set for Brevard on December 10, 1990, and for December 12, 1990, in Raleigh.

The Attorney General filed Notice of Intervention on July 1, 1990. AT&T Communications of the Southern States Inc. (AT&T), filed a Petition for Leave to Intervene on September 14, 1990, which was allowed by Order dated September 20, 1990.

On November 21, 1990, the Public Staff filed the testimony and exhibits of LuAnn Lenz, William J. Willis, Jr., Robert A. Goetz, John T. Garrison, and Leslie C. Sutton, Utilities Engineers, Public Staff Communications Division; John R. Hinton, Financial Analyst, Public Staff Economic Research Division; and J. Todd Clapp, Staff Accountant, Public Staff Accounting Division.

The hearing in Brevard was held as scheduled. The following public witnesses appeared and testified: Joseph N. Weidman, James E. Brannigan, John Clementson, Warren Weston, Joanne Paustian, Charles Cram, William Johnson Cathey, III, Tommy Owen, Anita Hillman, Herb Lester, Billy Layman, William F. Parker, John Nichols, Joe Potts, Robert McKown, William D. Hart, Paul Owenby, Ben Burgess, Abe Gosen, Bill Siniard, Waldemar Turowski, Harry Kopp, Jerry Arnold, and Charles Duke.

At the hearing in Raleigh, the Applicant offered the direct and rebuttal testimony and exhibits of Charles W. Pickelsimer, Jr., Vice President and General Manager, Citizens Telephone Company; Bruce H. Mottern, Supervisory Consultant - Revenue Requirements, John Staurulakis, Inc., consultant to Citizens; James H. Vander Weide, of Duke University and Financial Strategy Associates, consultant to Citizens; and William P. Wiltsee of Carnes, Burkett, Wiltsee & Associates, consultant to Citizens. The Public Staff offered the testimony and exhibits of LuAnn Lenz, William J. Willis, Jr., Robert A. Goetz, John T. Garrison, and Leslie C. Sutton, Utilities Engineers, Public Staff Communications Division; John R. Hinton, Financial Analyst, Public Staff Economic Research Division; and J. Todd Clapp, Staff Accountant, Public Staff Accounting Division.

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

FINDINGS OF FACT

1. The Applicant, Citizens Telephone Company, is a public utility as defined by G.S. 62-3(23), is subject to the jurisdiction of this Commission, and is properly before this Commission, pursuant to G.S. 62-133, for a determination of the justness and reasonableness of its proposed rates and charges.

2. By its application, the Company seeks rates to produce additional gross annual revenues of $1,313,798.

3. The test period consisting of the 12 months ended December 31, 1989, is representative and appropriate for use in this proceeding.

4. The overall quality of local exchange telephone service provided by Citizens is good.

5. The appropriate factors to use in separating investment and expenses among the jurisdictions are the separations factors from the 1989 cost study adjusted to reflect the 1991 transition year, as proposed by the Public Staff.

6. The Applicant's investment in fiber optic cable and terminals is reasonable and prudent and should be included in the determination of the appropriate levels of rate base, long distance revenues and operating expenses. The installation of fiber optic systems will accomodate the Company's subscriber growth and has resulted in an improved quality of service to Citizens' customers.

7. The Applicant's reasonable original cost rate base used and useful in providing telephone service within the State of North Carolina is $15,367,789. The rate base consists of telephone plant in service of $24,278,373,a working capital allowance of $176,699, and Rural Telephone Bank (RTB) stock of $371,594, reduced by accumulated depreciation of $6,556,926, deferred income taxes of $2,812,124, pre-1971 investment tax credits of $6,304, and an unamortized Customer Premises Equipment (CPE) gain of $83,523.

8. The end-of-period intrastate miscellaneous revenues should be increased by $162,850 to reflect the receipt of high cost assistance pursuant to Title 47 of the Code of Federal Regulations Part 36 Subpart F relating to the universal service factor.

9. The end-of-period intrastate intraLATA toll revenues should be based upon the separations factors from the 1989 cost study adjusted to reflect the 1991 transition year. The settlement pool calculation should include plant held for future use, Class B RTB stock and property taxes.

10. The Applicant's operating revenues for the test year under present rates after accounting, pro forma and end-of-period adjustments are $5,884,665.

11. The Applicant's reasonable level of test year operating revenue deductions after accounting, pro forma and end-of-period adjustments is $4,550,294. This level of test year operating expenses includes $1,293,787 of actual investment currently consumed by previous use recovered by depreciation expense.

12. The Applicant's income effect of other adjustments to net operating income found to be reasonable is $23,158.

13. The capital structure and cost rates reasonable and appropriate for use is this proceeding are:

Item	Ratios	Cost Rates
Long-term debt	55.05%	8.00%
Common equity	44.95%	12.70%

This combination of capital structure and cost rates yields an overall rate of return of 10.11%. The allowed rate of return on common equity does not include any adjustment for market pressure or flotation costs in this proceeding.

14. Based on the foregoing, the Applicant should be allowed to increase its annual level of gross revenues under present rates by $331,501. This increase would allow the Applicant the opportunity to earn the 12.70% rate of return on common equity which the Commission has found just and reasonable. This increased revenue requirement is based on the Company's original cost rate base and its reasonable test year operating revenues and expenses as determined in the above findings of fact.

15. Rates and charges designed pursuant to the guidelines discussed herein will produce the increase in revenues deemed reasonable and will be just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1, 2 AND 3

The evidence supporting these findings of fact is contained in the Company's verified application and the record as a whole. These findings are essentially informational, procedural and uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact is based on the testimony of the 24 public witnesses appearing at the hearing in Brevard, Company witness Pickelsimer's testimony, and Public Staff witness Goetz's testimony.

At the public hearing in Brevard, the majority of the public witnesses testified that Citizens was providing "good", "high quality", "excellent", "extremely reliable", "very good and dependable" telephone service. Several of these public witnesses testified that they had most definitely noticed improvements in the quality of their service since the installation of the Company's fiber optic systems.

The few public complaints were directed to the inability to reach discounted toll services such as Reach Out America, MCI or Sprint. Since, at present, toll calls are rated and billed by AT&T or Southern Bell, Citizens does not now have the information to allow Citizens to bill these calls. Citizens has been working on being able to provide these services since back in the summer and has made arrangements to get Associated Data Services (ADS) located in Rock Hill, South Carolina, to do their rating and printing which will permit these services to be offered. The Company expects by the second quarter of 1991 to be able to provide these services.

On questions regarding equal access (the ability to use an alternate carrier without dialing an access code), Company witness Pickelsimer testified that if the Company had installed equal access equipment without first having a request from one of the alternate carriers, the equipment would have to be paid for by the Company and recovered from local service revenues. Witness Pickelsimer stated that the Company has now received a request from MCI for equal access. Although it is given three years to make it available, the Company expects to have it in service within the next year. Under these circumstances, the cost of the equipment will be recovered through the National Exchange Carrier Association (NECA) pool.

The only service related problem about which testimony was offered related to a problem with a customer owned telephone. The other complaints were directed to the level of the increase in rates assuming that 100% of the amount originally sought was allowed by the Commission.

Public Staff witness Goetz testified that Citizens met or exceeded the Commission's quality of service objectives in 14 of 15 categories checked. In the category of paystations in service, Citizens had a failure rate of 13% compared to the objective of 10%. Witness Goetz also noted that Citizens may have failed to meet Commission objectives in the category of out-of-service troubles cleared within 24 hours for four months during the year 1989 and that data was missing for two additional months of that year. Witness Goetz testified that these possible failures may be attributable to problems with a new computer system rather than actual service problems. In conclusion, witness Goetz found Citizens' overall quality of service to be adequate.

Based upon the foregoing, the Commission concludes that the overall quality of service being provided by Citizens is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding of fact is based on the testimony and exhibits of Company witness Mottern and Public Staff witness Garrison. Witness Garrison testified and witness Mottern acknowledged that the calculation of separations factors is governed by procedures specified in Title 47 of the Code of Federal Regulations Part 36 (hereinafter referred to as Part 36) as adopted by the Federal Communications Commission (FCC). The FCC has implemented changes in the factors used to allocate Category 3-Local Switching Equipment and Subcategory 1.3-Exchange Line Cable and Wire Facilities.

In regard to the Category 3-Local Switching Equipment, the FCC is essentially going from a central office equipment composite allocator to a relative dial equipment minutes of use interstate allocator which is subject to a weighting factor in areas with fewer than 50,000 access lines. This change will be phased in gradually as specifically spelled out in Part 36 Section 36.125, with the transition being complete beginning in 1993.

In regard to the Subcategory 1.3-Exchange Line Cable and Wire Facilities, the FCC is essentially going from using the Subscriber Plant Factor allocator to a gross allocator with 25% of the costs assigned to this Subcategory 1.3 being allocated to the interstate jurisdiction. This change will be phased in gradually as specifically spelled out in Part 36 Section 36.154, with the transition being complete beginning in 1993.

The Public Staff reflected the effect of these factors in transition by adjusting the Company's 1989 cost study to reflect these factors at the 1991 levels which will be in effect when rates decided in this proceeding will go into effect. The Company had originally used its 1988 cost study and adjusted for the transition in these factors through 1989, the test year in this proceeding. However, at the hearing, the Company updated its position to reflect separations based on its 1989 cost study which had been approved after the filing of its application in this docket. The Company opposed the Public Staff's adjustment arguing that the use of the 1991 factor violates the concept of a test year and stated that if you do reach out to 1991 then all of the other revenues, expenses and rate base items should be updated.

The Commission believes that the Public Staff's recommendation to use the 1989 cost study adjusted for the specific 1991 factor transition previously described is appropriate for use in this proceeding. The Commission recognizes that the actual 1991 usage data is not now known and will, most likely, differ from the 1989 usage data, however, the manner in which the 1991 usage data will be used to determine the 1991 separations factors is known. Since the rates set in this proceeding will be charged to customers beginning in 1991, the Commission finds it appropriate to reflect the known changes to the separations procedures for the 1991 transition year to match the Company's current cost allocation policy. The Commission considers this treatment to be consistent with that adopted in Commission Orders in Docket No. P-19, Sub 207, and Docket No. P-118, Sub 39, in which the Commission adjusted cost study separations to reflect the FCC's transition methodology contained in the Part 36 rules. More specifically, in Docket No. P-19, Sub 207, which was in the matter of General Telephone Company of the South's last general rate case proceeding, the Order was issued in September 1986, the test year in that proceeding was for the 12-months ended September 30, 1985, and the Commission adopted the separations factors resulting from the use of a 1985 cost study adjusted for factor transition through 1986. In Docket No. P-118, Sub 39, which was in the matter of ALLTEL Carolina, Inc.'s last general rate case proceeding, the Order was issued in November 1986, the test year in that proceeding was for the 12-months ended December 31, 1985, and the Commission adopted the separations factors resulting from the use of a 1984 cost study adjusted for factor transition through 1986.

The difference in positions on the appropriate separations factors to be used causes differences between the parties on all items of rate base and all the components of net operating income. The numerical value of each of these differences is set forth in the discussion of the Evidence and Conclusions for Findings of Fact Nos. 7, 10, and 11 and the amount adopted by the Commission is disclosed therein. The separations factors adopted by the Commission are those factors contained in Public Staff witness Garrison's Exhibit No. JTG-1.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding of fact is based on the testimony and exhibits of Public Staff witness Sutton, Company witnesses Pickelsimer and Wiltsee and the public witnesses who testified at the hearing in Brevard. During the period between November 1985 and April 1989, Citizens replaced most of the copper cable connecting its remote units to the Brevard host switch with fiber optic cable. The question posed by the Public Staff was whether the Company's decision to replace this plant has been shown to have been "made in a reasonable manner and at an appropriate time on the basis of what was reasonably known or reasonably should have been known at that time." This is the standard the Commission used to judge claims of imprudence in Docket Nos. E-2, Sub 537, and Sub 333, In the Matter of Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges, and In the Matter of Investigation of Carolina Power & Light Company's Land Requirements Acquisition, and Disposal at the Shearon Harris Nuclear Power Plant, 94 P.U.R. 4th 353, 368 (1988).

Public Staff witness Sutton proposed a net adjustment of $2,275,856 to reduce Citizens' fiber optic investment in total Company operations. This adjustment consists of the following amounts:

No.	Public Staff Adjustment	Amount
1.	Elimination of 21 fiber optic umbilical cable placements made between November 1985 and February 1989	($2,026,418)
2.	Elimination of 21 fiber optic terminal placements made between November 1985 and April 1989	(588,511)
3.	Upgrade of existing copper cable and T-1 equipment	230,573
4.	Upgrade of existing central office equipment	108,500
5.	Net Adjustment	($2,275,856)

According to the testimony of witness Sutton, this adjustment was made based upon the following three arguments:

"1. Existing copper plant possessed sufficient, or nearly sufficient, capacity to serve every concentrator within Citizens' network. None of this plant has been shown to have outlived its service life, nor to have deteriorated or been damaged so as to render it unsuitable for use in carrying T-1 systems.

2. The Company's consulting engineers have stated that lightning and electrical interferences impacted service and led them to install fiber umbilicals in place of copper. Despite our repeated requests, neither these consultants nor Company officials have been able to produce any documentation supporting claims of unusual service problems.

3. Not once did Citizens or its consultants undertake any engineering economic study comparing the installation of new fiber routes to renovation of existing copper plant. This should have been done prior to authorizing such large expenditures. Had this analysis been carried out we believe Citizens would have found that fiber was an unwise choice."

Public Staff witness Sutton testified that the Public Staff had requested that Citizens provide documentation of the service problems which the Company attributed to its copper network. Witness Sutton testified that his examination of those Company records which were available, summarized in Pickelsimer Cross-Examination Exhibit 2, did not disclose any significant improvement in the category of cable/wire/carrier troubles between 1981 and 1990. This led him to conclude that the installation of Citizens' fiber optic network could not be justified on the basis of improvement of service.

Witness Sutton also challenged the installation of fiber optic cable on economic grounds. He testified that, in his opinion, the existing copper system could have been upgraded to provide an adequate level of service for the Company's customers. Witness Sutton noted that Citizens never undertook an economic study comparing the cost of installing new fiber with the cost of upgrading the existing copper plant. The only study, which was introduced into evidence as AG-Wiltsee Cross-Examination Exhibit 1, was premised on the comparison of new T-screen copper cable versus new fiber optic cable. This study was prepared by the consulting engineering firm of Carnes, Burkett, Wiltsee & Associates in March 1984 at the request of Citizens. It was the opinion of the Public Staff that because this study ignored the existence of the copper network in place, the results of the study were improperly biased.

In challenging the inclusion of Citizens' fiber optic network in rate base, the Public Staff did not maintain that this plant is not used and useful. The Public Staff pointed rather to the lack of sufficient evidence of prudence: was the replacement of existing copper with fiber shown to be the most reasonable, i.e., the most cost-effective way to provide adequate service to Citizens' customers? The Public Staff believed the Company's actions were imprudent and recommended that the Company should have installed some additional T-carrier equipment and two pieces of copper cable at a total cost of $339,073 rather than installing fiber optic cable at a cost of $2,614,929. Witness Sutton testified that the additional investment in copper and T-carrier equipment that he was proposing would improve capacity and be sufficient to accomodate subscriber growth beyond the test year into late 1990 based upon the data made available to him.

The Attorney General, in his proposed order, agreed with the Public Staff position on this issue. According to the Attorney General, under G.S. 62-75 the Company has the burden of proof to show that its actions are reasonable. In the Attorney General's opinion the Company has failed to meet this burden when it attempts to show the prudency of its investment in fiber optic trunking. Consequently, the Attorney General proposes to eliminate this investment.

According to witness Pickelsimer, if the Company were starting from scratch with no experience in the area, it would renovate the system as witness Sutton proposed. However, in fact, during the period of 1981 through 1985, Citizens had tried to improve service by using T-carrier on exchange cable as recommended by the Public Staff and in this regard, witness Pickelsimer testified that "unfortunately, it simply didn't work." Witness Pickelsimer testified that during this time period they had problems with induced voltage on the cables which corrupted the data going to the remote. This would cause the loss of all calls in progress and prevented the processing of any new calls until the situation was corrected. With such occurences, some units would return to service after the interference cleared, some larger switches required a technician to reload data from the main office after the trouble ended and others would require a trip to the remote to restore service. Witness Pickelsimer testified that during the summer months when thunderstorms and lightning are frequent occurences, the Company's repair people knew they were not going home at 5 o'clock but that they were going to get a lot of overtime. Witness Pickelsimer described lightning strikes which would blow the bonding and grounding straps off the innersheath in the pedestals in some of their longest, most inaccessible cables where they had T-carrier. In the opinion of witness Pickelsimer, the trouble reports during this time did not fully disclose the extent of this trouble. For instance, if the whole area served by a remote were shut down, the people served by it could not call to report the trouble. Instead, other customers would call in and report trouble calling out to the area. There may have been several hundred people who were without service or whose service was interrupted but they did not report the trouble since they could not call in. Witness Pickelsimer stated that the Company heard many general complaints about this type of trouble and knew it had to do something different to make service more reliable.

Company witness Wiltsee testified that Citizens had made repeated efforts to reduce its problems using standard industry mitigation methods. Further, he stated that investigations undertaken during the late 1970's and early 1980's led to the conclusion that for Citizens' facilities to meet industry standards, the only acceptable solution was to utilize other types of facilities, such as microwave radio or fiber optic systems.

According to the testimony of witness Wiltsee the host-remote umbilical links to the host DMS 100 switch in Brevard could have utilized T-carrier, microwave radio or fiber optic systems.

These three technologies were described by witness Wiltsee as follows:

> "T-carrier is a digital cable carrier, first introduced in the early 1960's, which can be implemented on exchange cable or cables dedicated to its use. When used on exchange or distribution cable it is susceptible to disruption due to the easy access afforded by this type cable. Use of "T" carrier on exchange cable was and is considered to be less than satisfactory and in the early 1970's a specialized cable was first manufactured expressly for "T" carrier use. This cable, known as "T" screen cable, required the minimum amount of field mounted equipment and since it was dedicated to carrier use, access could be limited. "T" carrier utilizing either cable configuration is inherently susceptible to electrical and lightning disruptions."
>
> "Microwave radio is a point-to-point radio system requiring a clear line-of-sight between points for operation. Digital microwave radio first became available in the early to mid 1980's."
>
> "Fiber optical systems transmit telephone messages over glass fibers utilizing light. These optical systems use fiber cables, which are immune to disruptions from lightning and other forms of electrical

interference, and are capable of spanning distances in excess of twenty miles without the need for regeneration. These systems as used today became available in the early 1980's."

Witness Wiltsee testified that he recommended the use of fiber optic systems to Citizens. In 1984, Carnes, Burkett, Wiltsee & Associates prepared a system design for Citizens relating to two routes. During the design process, witness Wiltsee stated that his firm eliminated the use of T-carrier, utilizing copper exchange cable, from further consideration as it could do nothing to improve Citizens' service. Digital microwave radio was also eliminated due to the number and diverse locations of the remote line units. Preliminary map studies indicated that clear line-of-sight paths between the host office and the remotes did not exist. Studies were performed comparing T-carrier utilizing T-screen cable versus fiber optical systems. These studies indicated that fiber was the preferred choice when compared on a present worth of annual charge basis and considering the service improvements fiber offered. It is the opinion of witness Wiltsee that Citizens would have been unable to provide good telephone service uniformly throughout its service area without the installation of fiber optic host-remote umbilical links.

Witness Wiltsee was questioned on cross-examination as to whether his study would explicitly support every placement of fiber that Citizens made and responded by stating that "These studies do not support that explicitly. But in our judgment and in the five years' experience that we've had both with Citizens and other telephone companies, I could make these studies repeatedly, and each study would prove that fiber optics can be justified over alternative copper T-screen facilities."

According to the testimony of witness Pickelsimer, when the Company finally decided to install fiber optic cable, the installation of their first 20% of fiber optic cable was put out for bids. The Company received two bids. The lowest bid was for $350,000, and the other was for over $500,000. The Company decided to do the job itself, bought the necessary equipment and completed the job at a cost of $250,000. Consequently, the Company concluded that they would do the remaining 80% themselves to get it done at a reasonable price.

At the public hearing in Brevard, the majority of the 24 public witnesses testified that the quality of the telephone service being provided by Citizens was very good. Several of these public witnesses testified that they had most definitely noticed improvements in the quality of their service since the installation of the fiber optic systems. Specifically, comments in this regard were made as follows:

I. John Clementson testified as follows:

"The area in which I live is commonly known within this county as the Little River Area. It's approximately a 20-minute drive from where we're sitting right now. I have lived in that area since early 1985. The point to which I speak has to do with what I consider to be a major improvement in service. Until approximately two years ago, I'm not terribly positive about that date, with fair frequency, particularly when there were electrical storms which the natives of this area know can occur in the winter as well as the summer, there were frequent interruptions of service. It was virtually a predictable item. Beginning with approximately two years ago, there has been to my knowledge, to my service, no interruption whatsoever. And I understand, and I'm not a technician, that this has something to do with the updating and the upgrading of possibly the utilization of fiber optic equipment to the service where I live. I should comment that we have two telephone lines that come into my house. I do have an office in my office [sic]. With great frequency, I receive long distance calls from, sometimes overseas locations, and with some degree of frequency, I receive comments about the quality, the voice quality, the high quality that the person who's calling me is observing. Basically, I'm saying that the service has seen a material improvement in approximately the last two years. I have a personal aside. I think with what little I know about this subject that we are observing a very rare circumstance in today's day and time where a service and an improvement has been delivered in advance of us, as citizens, being asked to pay for it. I think if you'll compare that, it's very possibly a rather unusual occurrence in this particular time."

2. William Johnson Cathey, III testified as follows:

"In the last three years with the installation of this fiber optics, the service has improved in the upper end of the County, in the Town of Rosman. It's very clear. As the other gentleman testified beforehand, I've had no interruptions in service, which used to be the case during electrical storms. As a point of fact, I had a defendant up here in court who ran into a power pole down there and knocked out power to the upper end of the County. I was unable to recharge the battery to my walkie talkie that's issued to me by the Town of Rosman and I had to use the phone to communicate during this situation, when there was absolutely no power available. I had no interruptions at all, pleased with the service."

3. Billy Layman described his experience while being the Chief of Telecommunications at the Department of Defense (DOD) facility at the Rosman Research Station and testified as follows:

"I was a part of the original group who came in and took over the facility as DOD and at that time, we had nothing but T-1 Carriers and central office cable type communications off of the station. They were horrible. We were out an inordinate amount of times. As a matter of fact, many of my people at times even called Mr. Pickelsimer personally at home, two or three o'clock in the morning, when we had circuit outages. We had numerous type of communications off of the station and I was part of the DOD team that worked with Citizens Telephone Company in getting fiber optics extended into the Research Station and although I have been retired now for three years from the station, from DOD, in checking with the, my co-workers up there recently, based upon the experience that I've had and with theirs, the communications increased tremendously. There is just absolutely no comparison. We suffered very serious outages and which also included the Balsam Grove area. As a matter of fact at one time, by the nature of using the T-1 repeaters coming off the station, they were cut and the DOD facility was totally out of communication for approximately about four days--no, it wasn't it either--beg your pardon, because they came back up there and worked during the night. We were out for about, I guess for about 36 hours but with fiber optics, extremely reliable communications has been experienced by the station. And, yes, I am a user of Citizens telephone facilities. I have had no bad experiences with the telephone company out where I live at the present but I used to live out at Sherwood Forest, down at Cedar Mountain and that was back between the '81 and '85 time frame and I do know we had very poor communications there but again, I contribute that, by being in communications, to the T-1 carriers and again, the central office cable that was being used and I'm assuming is still being used in that facility; I'm not sure."

4. John Nichols testified as follows:

"I'm a self-employed businessman. I've been here 22 years and I depend on the telephone every day and I can truthfully say that three or four years ago and back, we had a lot of problems and a lot of difficulties with our telephones and since the fiber optic cable has been installed, our phone has improved 100 percent."

5. Joe Potts testified as follows:

"...I certainly have no complaints about recent phone service. The standard joke around Brevard used to be, when it rains, the string breaks, and I think that was a pretty fair assessment at one time, having had that problem, as I say, in recent memory."

6. Robert Mckown testified as follows:

"The service, I think has been better since we got the fiber optic cable out in our area. I've never been a technical buff but I do know that the fidelity of the sound of our phone has been real good and my wife and I don't remember the last time we had a service outage."

7. Paul Owenby testified as follows:

"Our business was like everybody's; when it rained, it was bad. We got a lot of cutoffs but the [sic] excellent service now, very excellent service."

8. Charles Duke testified as follows:

"I've been here 15 years and probably, when I was a businessman, I retired last year, I was probably Mr. Pickelsimer's severest critic for a while. In fact, I think I wrote the Utilities Commission a letter about the phone service. This was probably the latter part of the '70s, beginning of the '80s. We use the phone extensively for our business. We're in the real estate business and probably our phone bill at that time was in the thousands of dollars a month. However, I've got to say this. In the last five years or three and a half years, the phone service has been excellent and I'm sure it's due to the installation of the fiber optics. I now have two phones in my home and a FAX machine and I never have a problem."

Based upon the evidence, the Commission concludes that the Company's investment in fiber optic cable and terminals was a reasonable decision. The Commission believes that the Company acted in a reasonable manner in evaluating the options available for improving the quality of its service to the current level.

The Company witnesses testified that they had tried to improve service during the period from 1981 through 1985, in the manner proposed by the Public Staff, by using T-carrier on exchange cable and found that this would not correct the problems related to the high incidence of lightning and electrical powerline influence inherent in Citizens' franchised service area. The Company hired the outside consulting engineering firm of Carnes, Burkett, Wiltsee & Associates who recommended the use of fiber optic systems to correct the Company's existing problems. In this proceeding, Company witness Wiltsee stated that in the design process he had eliminated the use of T-carrier, utilizing exchange cable, from further consideration as it could do nothing to improve Citizen's service. Further, he eliminated the consideration of digital microwave radio since map studies of Citizens' service area indicated that clear line of sight paths did not exist where needed. Studies were performed by Carnes, Burkett, Wiltsee & Associates in March 1984 comparing the installation of new T-carrier utilizing T-screen cable versus fiber optic systems, involving two proposed routes, with the results indicating that fiber was the preferred choice when compared on a present worth of annual charge basis and considering the service improvements fiber offered. Even though these studies pertained to only two proposed routes, witness Wiltsee stated that he "could make these studies repeatedly, and each study would prove that fiber optics can be justified over alternative copper T-screen facilities."

Witness Pickelsimer testified that the Company had initially received bids on the cost of installation of the first 20% of its fiber optic cable installation and had decided to do the job themselves realizing a savings of $100,000 compared to their lowest bid. Consequently, the Company decided to install all of its fiber optic system.

The Commission believes that Citizens' installation of fiber was the product of careful and conscientious study by the Company and its engineers. Citizens is providing good and improved service to its customers as affirmed by the testimony of the public witnesses appearing in this proceeding. The Commission finds that the Company's action was reasonable and prudent considering the nature of the problems described in the testimony of the Company's witnesses and the fact that fiber is immune to disruptions from lightning and other forms of electrical interference. The Commission can find no compelling justification in the evidence to show that the Company was imprudent in what it did. The Public Staff's proposal to install additional T-carrier and copper cable will accomodate subscriber growth into late 1990, whereas the Company's installation of fiber optic systems will accomodate growth and has also corrected problems described by the witnesses relating to lightning and other forms of electrical interference. The Public Staff has not demonstrated the existence of an available prudent alternative that the Company should have followed to accomplish management's primary desired result, a significantly improved quality of service. Therefore, the Commission concludes that the Company should be allowed to earn a return on its fiber optic investment which is used and useful in providing service to its customers. Consequently, the Commission concludes that telephone plant in service, accumulated depreciation reserve, accumulated deferred income taxes, toll settlement revenues, and depreciation expense should be appropriately adjusted to reflect the inclusion of the Company's fiber optic investment.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence concerning the proper intrastate original cost rate base is found in the testimony and exhibits of Company witnesses Pickelsimer, Mottern and Wiltsee and Public Staff witnesses Clapp, Garrison, and Sutton. The following chart summarizes and compares the Company's proposed rate base and the amount proposed by the Public Staff as reflected in their respective proposed orders.

Item	Company	Public Staff	Difference
Telephone plant in service	$24,723,891	$22,604,968	$(2,118,923)
Accumulated depreciation	(6,679,964)	(6,378,036)	301,928
Net telephone plant	18,043,927	16,226,932	(1,816,995
Working capital:			
Cash	223,000	235,270	(730)
Materials and supplies	150,441	150,351	(90)
Prepayments	12,430	12,400	(30)
Average tax accruals	(200,126)	(199,644)	482
Customer deposits	(22,087)	(21,678)	409
Total working capital	176,658	176,699	41
Accumulated deferred income tax	(2,901,363)	(2,616,043)	258,320
Pre-1971 investment tax credit	(6,421)	(6,304)	117
Investment in RTB stock	378,488	317,594	(6,894)
Unamortized CPE gain	(83,523)	(83,523)	-
Original cost rate base	$15,607,766	$14,069,355	$(1,538,411)

At the hearing, Company witness Mottern stipulated that he agreed to several adjustments calculated by the Public Staff. These adjustments included the reclassification of the CPE depreciation reserve to nonregulated operations, the apportionments to nonregulated operations, the inclusion of the unamortized CPE gain as a reduction in rate base, the calculation of cash working capital, the expiring amortizations, and the removal of pro forma capitalizable payroll. The Commission, therefore, finds that these adjustments and the resulting amounts, based upon the Commission's adoption of the Public Staff's recommended separations factors, are reasonable and proper for use in the determination of original cost rate base.

Telephone Plant in Service

The first component of rate base on which the parties disagree is telephone plant in service. The Public Staff recommended an amount that was $2,118,923 below the Company's proposed amount of $24,723,891. This difference in plant in service is composed of the following items:

No.	Item	Amount
1.	"SEPARATIONS RECALCULATION"	$ (447,596)
2.	Apportionments to nonregulated operations	1,536
3.	Pro forma capitalizable payroll	542
4.	Fiber optic plant investment	(1,673,405)
5.	Total difference	$(2,118,923)

The first item which is referred to as "SEPARATIONS RECALCULATION", is the difference which exists between the Company's original position on telephone plant in service restated to reflect the Company's change to its 1989 cost study separations factors and the recalculation of the Company's original position on telephone plant in service to reflect the Public Staff's separations factors which are based on the 1989 cost study adjusted for the 1991 transition of certain factors. Additionally, for each item included in rate base there will be a difference referred to as "SEPARATIONS RECALCULATION", with the source of such difference being the same as just described for telephone plant in service. As discussed in the Evidence and Conclusions for Finding of Fact No. 5, the Commission concludes that the Public Staff's separations factors are appropriate and therefore telephone plant in service should be reduced by $447,596.

As stated earlier, Company witness Mottern agreed with the Public Staff's apportionments to nonregulated operations and the removal of pro forma capitalizable payroll. The only existing differences in these two adjustments is due to differences in separations factors. The Commission accepts the Public Staff position as it reflects the appropriate separations factors.

The remaining item of difference is the Public Staff's adjustment for what it believed was an imprudent plant investment in fiber optic cable. The Commission has determined in the Evidence and Conclusions for Finding of Fact No. 6 that the Company's investment in its fiber optic systems was proper and reasonable. Based upon the foregoing, the Commission finds that the proper amount of telephone plant in service is $24,278,373.

Accumulated Depreciation

The second area of difference in rate base is the proper level of accumulated depreciation. The $301,928 difference is composed of the following items:

No.	Item	Amount
1.	"SEPARATIONS RECALCULATION"	$ 123,926
2.	Reclassification of CPE depreciation reserve	76
3.	Apportionments to nonregulated operations	(903)
4.	Expiring amortizations	(38)
5.	Pro forma capitalizable payroll	(23)
6.	Fiber optic plant investment	178,890
7.	Total difference	$ 301,928

The first item of difference is the "SEPARATIONS RECALCULATION" impact of $123,926. The Commission finds that this adjustment as proposed by the Public Staff is required to reflect the appropriate separations factors. Further, in item nos. 2, 3, 4 and 5, witness Mottern stated, at the hearing, that he agreed with these adjustments except that he proposed different separations factors. Again, the Commission agrees with the Public Staff's separations factors and accepts these adjustments as proposed by the Public Staff. The final item of difference in accumulated depreciation is the Public Staff's plant investment adjustment removing the Company's fiber optic systems. The Commission, as discussed previously, has concluded that the Company's investment in its fiber optic system was a reasonable action. Thus, the Public Staff adjustment in this regard, will not be allowed. Based on the foregoing, the Commission finds that the proper amount of accumulated depreciation is $6,556,926.

Working Capital

The third area of difference in rate base is the working capital allowance. Working capital is composed of a cash requirement, materials and supplies, prepayments, and reduced by average tax accruals and customer deposits. The Public Staff and the Company used the same methodology to calculate cash working capital, using one-twelfth of their proposals for operating expenses, excluding depreciation. Additionally, the Public Staff's adjustments to the working capital allowance also reflect the difference between the Company's separations factors and those recommended by the Public Staff. Based upon the operating expenses, excluding depreciation, found reasonable in Finding of Fact No. 11, and the separations factors adopted in Finding of Fact No. 5, the Commission finds that $235,270 is the proper level of cash working capital.

Further, the Commission finds that in accordance with its finding on the appropriate separation factors, the proper levels of materials and supplies, prepayments, average tax accruals, and customer deposits are $150,351, $12,400, $(199,644), and $(21,678), respectively.

Accumulated Deferred Income Taxes

The next area of difference in original cost rate base is the proper level of accumulated deferred income taxes. The $285,320 difference is composed of the following items:

No.	Item	Amount
1.	"SEPARATIONS RECALCULATION"	$ 53,029
2.	Flowback of excess tax reserves	36,210
3.	Fiber optic plant investment	196,081
4.	Total difference	$ 285,320

As discussed previously, the adjustment of $53,029 labelled "SEPARATIONS RECALCULATION" arises strictly due to differences in separations. In this regard, the Commission accepts the Public Staff's adjustment which reflects the appropriate separations factors.

The second item of difference results from witness Clapp's revision of his original testimony at the hearing. In his prefiled testimony, witness Clapp included an adjustment to reduce the Company's federal income tax expenses to reflect the flowback of excess deferred tax reserves, but failed to reflect the appropriate corresponding adjustment to reduce the current balance of accumulated deferred income taxes. The Company, in its proposed order, adopts the Public Staff's federal income tax expense adjustment to reflect the flowback of excess deferred tax reserves, but also overlooks the corresponding adjustment as had been initially done by the Public Staff. The Commission finds that it is appropriate to reduce the balance of accumulated deferred income taxes to reflect the flowback of excess deferred income taxes as proposed by the Public Staff and found reasonable in Finding of Fact No. 11.

The final item of difference is the Public Staff's plant investment adjustment to remove the fiber optic systems. The Commission has determined in Finding of Fact No. 6 that this adjustment is inappropriate. Therefore, the Commission finds that the proper level of deferred income taxes is $2,812,124.

Pre-1971 Investment Tax Credit and Investment in RTB Stock

The final two areas of difference in rate base relate to the proper level of pre-1971 investment tax credits and investment in Rural Telephone Bank (RTB) Stock. The differences between the parties in these two categories are due entirely to the parties' differences in separations factors. As discussed in the Evidence and Conclusions for Finding of Fact No. 5, the Commission adopted the separations factors proposed by the Public Staff. Therefore, the Commission agrees with the Public Staff's position on pre-1971 investment tax credits and the level of investment in RTB Stock.

Based upon the foregoing conclusions, the Commission finds that the appropriate original cost rate base for use in setting rates in this proceeding is $15,367,789, as shown in the following chart:

Item	Amount
Telephone plant in service	$24,278,373
Accumulated depreciation	(6,556,926)
Working capital:	
Cash	235,270
Materials and supplies	150,351
Prepayments	12,400
Average tax accruals	(199,644)
Customer deposits	(21,678)
Accumulated deferred income taxes	(2,812,124)
Pre-1971 investment tax credit	(6,304)
Investment in RTB stock	371,594
Unamortized CPE gain	(83,523)
Original cost rate base	$15,367,789

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding of fact is based on the testimony and exhibits of Company witness Mottern and Public Staff witness Garrison. In the original prefiled testimony of witness Garrison, an adjustment was made to increase the Company's intrastate miscellaneous revenues by $188,680, to reflect the estimated impact of Citizens' participation in the FCC's Part 36 Subpart F high cost assistance program.

Pursuant to Subpart F of the FCC's Part 36 rules, Citizens receives an expense adjustment to offset the high cost of providing service. This high cost assistance program enables local telephone companies with very high per loop costs to allocate more of their loop costs to the interstate jurisdiction, thus recovering these costs from interexchange carriers and leaving fewer costs to be recovered through intrastate rates. The high cost assistance program is intended to hold down local rates and to achieve a goal of the FCC and state Commissions, which is the preservation of universal service.

According to the FCC's Part 36 rules, this expense adjustment is added to interstate expenses and deducted from intrastate expenses after the normal jurisdictional separations studies have been performed. In the Company's original testimony no such adjustment was made; however, in the Company's proposed order, Citizens recommended that the Company's intrastate miscellaneous revenues should be increased by $107,909 which, according to witness Mottern, is the actual amount of this interstate revenue received by the Company in 1989. On cross examination, witness Garrison accepted that the amount of high cost assistance received by the Company in 1990 was $135,708. Because this high cost assistance program is in transition, the amount that Citizens received in 1990 is only five-eighths of the high cost amount it would receive were the program not in transition. Consistent with the 1991 transition year used for separations by the Public Staff, the Public Staff recommended that the high cost assistance amount for 1990 should be adjusted to reflect the transition year 1991. This results in the Public Staff's recommendation of $162,850 which represents six-eights of the high cost amount it would receive if the program was not in transition, based upon the dollars actually received in 1990.

The Commission agrees with the Public Staff that the amount of the high cost assistance should reflect the 1991 transition, as found appropriate in Finding of Fact No. 5, and miscellaneous revenues should be increased by $162,850. The Commission finds that this amount reflects the known high cost assistance received by Citizens, adjusted for the known and measurable 1991 transition effect of the high cost assistance program.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence for this finding of fact is based on the testimony and exhibits of Company witness Mottern and Public Staff witness Garrison. Witness Mottern's final position, as presented in the Company's proposed order, reflected preliminary end-of-period intrastate intraLATA toll revenues of $1,584,676, whereas, the final position of witness Garrison was $1,760,744, a difference of $176,068.

In its initial calculation of settlement pool revenues, the Company left out the investment in plant held for future use, failed to include property tax expense and included no amount for the amortization of the investment tax credits. The Public Staff's initial calculation reflected an adjustment to include both the plant held for future use and property taxes. Additionally, the Public Staff's original calculation excluded the investment in Class B RTB stock which had been included by the Company. The parties are now in agreement on the methodology to be used in calculating end-of-period toll settlement revenues. They agree that the calculation of net investment should include the Company's investment in plant held for future use and Class B RTB stock and that the calculation of operating expenses and taxes should include property taxes. The Company and the Public Staff also agreed that the 1989 actual intrastate intraLATA pool rate of return of 26.61% was appropriate to use in this proceeding to calculate intrastate intraLATA toll revenues. The Company has revised its position such that it includes the amortization of investment tax credits in its preliminary end-of-period intrastate intraLATA toll revenue calculation, whereas the Public Staff has reflected the amortization of the investment tax credit as an additional adjustment to its preliminary end-of-period intrastate intraLATA toll revenue calculation. The resulting difference between the parties is due to differences of opinion on the appropriate separations factors. As previously discussed, in Finding of Fact No. 5, the Commission adopts the separation factors of the Public Staff and thus, accepts that the preliminary end-of-period intrastate intraLATA toll revenue level is $1,760,744 which is prior to any of the Public Staff's pro forma and accounting adjustments. The Commission finds that the settlement pool calculation for Citizens should reflect plant held for future use, Class B RTB stock, and property taxes as agreed to by the parties.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the testimony and exhibits of Company witness Mottern and Public Staff witnesses Clapp, Garrison, and Willis. According to the proposed orders filed by the parties, the appropriate level of operating revenues is as shown in the following chart:

Item	Company	Public Staff	Difference
Local service	$ 2,551,022	$ 2,551,022	$ -
Network access	794,671	794,671	-
Long distance	1,519,196	1,599,917	80,721
Miscellaneous	792,735	847,676	54,941
Uncollectibles	(1,531)	(1,531)	-
Total operating revenues	$ 5,656,093	$ 5,791,755	$135,662

The Public Staff and the Company agreed on the appropriate level of local service revenues, network access revenues and uncollectibles. Since there is no evidence to the contrary, the Commission finds that the amounts presented by the parties for local service revenues, network access revenues, and uncollectibles are appropriate for purposes of this proceeding.

Long Distance Revenue

The first area of difference in operating revenues is the appropriate level of long distance revenue. The Public Staff recommended an amount that was $80,721 above the Company's proposed amount of $1,519,196. This difference in long distance revenue is composed of the following items:

No.	Item	Amount
1.	Adjustment to preliminary end-of-period level	$176,068
2.	Effect of Public Staff rate base adjustments excluding fiber optic systems adjustment	2,106
3.	Effect of Public Staff operating expense and other tax adjustments excluding fiber optic systems adjustment	(4,543)
4.	Effect of Public Staff rate base adjustments relating to fiber optic systems adjustment	(80,871)
5.	Effect of Public Staff operating expense adjustment relating to fiber optic systems adjustment	(12,039)
6.	Total difference	$ 80,721

The first item of difference in the amount of $176,068 relates to matters which were discussed in the Evidence and Conclusions for Finding of Fact No. 9; therein, the Commission adopted the Public Staff's position in this regard.

The next two adjustments relate to rate base and operating expenses and other taxes adjustments which were proposed by the Public Staff and agreed to by the Company with the resulting difference, as shown, being entirely due to the parties' use of different separations factors in the calculation of each individual adjustment. The Commission has previously discussed the appropriate separations factors and agreed with the Public Staff. Accordingly, the Commission finds the Public Staff's rate base adjustments totalling $2,106 and the Public Staff's operating expense and other tax adjustments totalling $4,543 to be appropriate.

The remaining two adjustments reflect the Public Staff's proposed exclusion of the Company's investment in fiber optic systems. Consistent with the findings discussed in the Evidence and Conclusions for Finding of Fact No. 6, the Commission concludes that the Public Staff's adjustments in this regard are inappropriate. On the basis of the foregoing, the Commission finds that the appropriate level of long distance revenues is $1,692,827.

Miscellaneous Revenue

The final area of difference concerns miscellaneous revenue. The difference of $54,941 results from the parties' varying adjustments to reflect the receipt of high-cost assistance pursuant to Subpart F of the FCC's Part 36 rules. Based on the Evidence and Conclusions for Finding of Fact No. 8, the Commission finds that intrastate revenues should be increased by $162,850 and that the appropriate level of miscellaneous revenue is $847,676.

Based on the foregoing, the Commission finds that the appropriate level of operating revenues for the test year under present rates is $5,884,665 as shown in the following chart:

Item	Amount
Local service	$2,551,022
Network access	794,671
Long distance	1,692,827
Miscellaneous	847,676
Uncollectibles	(1,531)
Total operating revenues	$5,884,665

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence concerning this finding of fact is found in the testimony and exhibits of Company witnesses Mottern, Pickelsimer, Wiltsee and Public Staff witnesses Clapp, Garrison, and Sutton. The following chart summarizes the parties' positions regarding operating revenue deductions as set forth in their respective proposed orders.

Item	Company	Public Staff	Difference
General support	$ 376,609	$ 369,748	$ (6,861)
Central office switching and transmission	326,697	304,883	(21,814)
Information origination/ termination	39,602	39,579	(23)
Cable and wire facilities	727,136	686,322	(40,814)
Network operations	230,482	226,283	(4,199)
Depreciation and amortization	1,277,271	1,218,975	(58,296)
Services	578,968	603,081	24,113
Executive and planning	182,144	182,138	(6)
General and administrative	409,488	409,474	(14)
Interest on customer deposits	1,767	1,732	(35)
Total O&M expenses	4,150,164	4,042,215	(107,949)
Gross receipts	82,143	82,143	-
Other taxes	123,751	121,533	(2,218)
State income tax	40,788	64,835	24,047
Federal income tax	68,991	179,723	110,732
Total operating revenue deductions	$4,465,837	$4,490,449	$ 24,612

At the hearing, Company witness Mottern accepted in principle all adjustments to operating revenue deductions made by the Public Staff except for the adjustment to depreciation expense relating to the Company's investment in fiber optic systems. The Commission, having adopted the Public Staff's separations factors as previously discussed, finds that all the expense adjustments made by the Public Staff, and the resulting amounts except for those relating to fiber optic plant investment and operating taxes, are reasonable and proper for use in this proceeding. The differences between the parties are entirely due to their use of different separations factors to compute the identical adjustment except, of course, the Public Staff adjustment to remove fiber optic plant investment, which would also cause a difference in the parties' proposed state and federal income taxes.

The remaining difference is the Public Staff's adjustment to reduce depreciation expense to correspond with its adjustment to remove the Company's investment in fiber optic systems. Based on the Commission's conclusion in Finding of Fact No. 6, the Commission finds that the Public Staff's corresponding adjustment to depreciation expense of $74,812 is inappropriate in this proceeding.

The Public Staff and the Company agreed that the gross receipts tax should be $82,143. However, the Commission finds that the gross receipts tax should be $82,094 which would properly reflect the deduction of uncollectibles from local service revenues prior to calculating gross receipts tax.

Further, the Commission finds that the level of other taxes which includes regulatory fee expense, among other things, should be adjusted to properly reflect the Commission's calculation of operating revenues net of uncollectibles, resulting in an other taxes expense level of $121,788.

The difference in state income taxes and federal income taxes is due to the differences in the various components of taxable income and deductible expenses proposed by the Company and the Public Staff. Based on our findings as to the various components of taxable income and deductible expenses, the Commission concludes that a state income tax expense level of $62,087 and a federal income tax expense level of $167,298 are appropriate under present rates.

Based on the foregoing, the Commission finds that the Company's reasonable level of operating revenue deductions is $4,550,294 as shown in the following chart:

Item	Amount
Operating expenses	$2,821,508
Depreciation and amortization	1,293,787
Interest on customer deposits	1,732
Operating taxes other than income taxes	203,882
State income tax	62,087
Federal income tax	167,298
Total operating revenue deductions	$4,550,294

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence concerning the proper income effect of other adjustments to net operating income is found in the testimony and exhibits of Company witness Mottern and Public Staff witness Clapp. The following chart summarizes the amounts which the Company and the Public Staff contend constitute the income effect of other adjustments to be used in this proceeding.

Item	Company	Public Staff	Difference
CPE gain amortization	$ 20,881	$ 20,881	$
Interest related to flow through of excess DIT reserves	2,318	2,277	(41)
Total difference	$ 23,199	$ 23,158	$ (41)

The only difference is in the parties' interest related to the flow through of excess deferred income tax reserves. This difference exists entirely because of the parties' varying positions on separations factors. Consistent with our finding on the appropriate separations factors, the Commission finds that other adjustments to net operating income totalling $23,158 are reasonable and proper for use in determining rates in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence for this finding of fact is based on the testimony and exhibits of Company witnesses Mottern and Vander Weide and Public Staff witness Hinton.

The capital structure recommended by the Public Staff for use in this proceeding is the September 30, 1990, quarter-ending capital structure for the Company adjusted to remove the equity financing related to the Company's cable TV (CATV) investment, consistent with the treatment in the Company's last general rate case proceeding in Docket No. P-12, Sub 80. Witness Hinton recommended a cost rate for long-term debt of 8.00% which was the Company's actual embedded cost of debt as of September 30, 1990.

The Company had originally proposed the use of its December 31, 1989 capital structure. In its proposed order, the Company agreed that the Public Staff's proposed capital structure was the most recent and, therefore, the more appropriate capital structure. The Company also agreed that 8.00% was the appropriate embedded cost of long-term debt.

Based upon the foregoing, the Commission finds that the actual September 30, 1990, capital structure is appropriate for use in this proceeding. Furthermore, the actual embedded cost of debt of 8.00% as of September 30, 1990, which was proposed by the Public Staff is, likewise, found to be reasonable and appropriate for use in this proceeding.

The Company and the Public Staff were not in agreement on the proper investor return requirement for common equity. Company witness Vander Weide recommended that the Commission recognize 14.50% as the cost of common equity to Citizens in this case. Public Staff witness Hinton recommended that the Commission recognize 12.65% as the cost of common equity for the Company in this case.

In his pre-filed testimony, Company witness Vander Weide employed two different methods in his cost of equity analysis. Dr. Vander Weide employed the quarterly discounted cash flow (DCF) model and the risk premium method in his return on common equity recommendation.

In applying the quarterly DCF model, Dr. Vander Weide chose to study two groups of companies: (1) a group of risk comparable companies selected by using cluster analysis, and (2) the Regional Bell Holding Companies (RBHCs). Since Citizens Telephone Company has no publicly traded common stock, the DCF model could not be directly applied. Using the quarterly DCF model, witness Vander Weide determined that the investor return requirement was in the range of 14.00% to 15.20%. In employing the risk premium method, Dr. Vander Weide made two studies: (1) yields of Standard and Poors' (S&P) 500 stock portfolio were compared to yields of Moody's A-rated utility bonds portfolio and (2) yields of the S&P 40 utility stock portfolio were compared to yields of Moody's A-rated utility bonds portfolio. The results of these risk premium studies yielded a range in the cost of common equity of 14.00% to 15.50%. This range of returns resulted when the calculated risk premium was added to average interest rates on Moody's A-rated utility bonds over three months ending May 1990. Dr. Vander Weide provided additional testimony that the common equity returns under the risk premium method would change to a range of 13.75% to 15.25% when the calculated risk premium was added to average interest rates on Moody's A-rated utility bonds over three months ending November 1990.

From the results of his DCF and risk premium studies, Dr. Vander Weide concluded that the cost of equity to Citizens was in the range of 14.00% to 15.50%. His final cost of equity recommendation to the Commission was 14.50%.

Public Staff witness Hinton employed the annual DCF method in his analysis of the investor return requirement for Citizens. In performing his DCF analysis, he looked at four groups of companies which would provide market information indicating the investor required return for Citizens: (1) Group A was constructed to include telecommunications companies that derive more than 80% of their revenues from regulated operations, (the group includes the RBHCs used by Dr. Vander Weide) (2) Group B was constructed to include telecommunications companies that receive a larger portion of their revenues from various non-regulated ventures than companies included in Group A, (3) Group C was composed of non-telephone utilities, and (4) Group D was composed of non-utility companies. The results of these DCF analyses yielded ranges in the cost of equity as follows: (1) Group A-12.10% to 12.90%, (2) Group B-11.90% to 13.50%, (3) Group C-11.80% to 12.50%, and (4) Group D-12.30% to 13.30%.

From the results of these DCF applications, witness Hinton concluded that the cost of equity to Citizens was in the range of 12.20% to 13.10%. His final cost of equity recommendation to the Commission was 12.65%.

In his pre-filed testimony, witness Hinton also reviewed the testimony of Company witness Vander Weide. Witness Hinton noted in his opinion that Dr. Vander Weide's DCF analysis contained three adjustments which were inappropriate. First, witness Hinton was opposed to the use of the quarterly DCF model stating that quarterly indexing is simply not a proper adjustment in a cost of common equity determination. Second, witness Hinton objected to Dr. Vander Weide's flotation cost adjustment stating that a utility should be allowed the opportunity to recover known and actual costs associated with public issuances of new common shares, but Citizens has never incurred such costs and so there are no flotation costs in this particular case. And last, witness Hinton did not agree with Dr. Vander Weide's "cellular phenomenon" adjustment, since in his opinion the current investor environment does incorporate the effect of the cellular properties in deriving its expectations of the performance of the stock. Thus, Dr. Vander Weide's premise that the growth expectations derived from cellular operations are being omitted from the consensus analysts' forecasts was not true in witness Hinton's opinion.

During cross-examination by the Attorney General, Public Staff witness Hinton attempted to quantify the effect of removing from the DCF model the adjustments of Dr. Vander Weide that he opposed. Dr. Vander Weide acknowledged that removing each of these adjustments results in a lower DCF calculation. This is true no matter what form of the DCF is employed. Witness Hinton's quantification which was admitted as Exhibit JRH-8, indicated that adjusting the DCF to remove Dr. Vander Weide's adjustments, but retaining the price, dividend, and growth factors that he employed, resulted in an indicated cost of equity of 12.50%. Specifically, witness Hinton's Exhibit JRH-8 indicated that removing the "cellular phenomenon" adjustment lowers the DCF result by 220 basis points, that removing the flotation cost adjustment lowers the DCF result by 40 basis points, and that employing the annual model lowers the DCF result by 50 basis points. However, on recall to the witness stand, Dr. Vander Weide stated that the cost of equity on Exhibit JRH-8 should be 12.90% not 12.50% in order to reflect the next period's dividend, not just the current dividend; such adjustment, in Dr. Vander Weide's opinion, would be consistent with the theory of witness Hinton's annual DCF model. Dr. Vander Weide testified that this did not represent his position on the required return on common equity for Citizens.

Witness Vander Weide was extensively cross-examined on his application of the quarterly DCF model in this case. Witness Vander Weide acknowledged that in Carolina Power and Light Company's (CP&L) last general rate case proceeding Docket No. E-2, Sub 537, the Commission was of the opinion that the investors' behavior is more on an annual model than on a quarterly model and thus adopted the annual DCF. On cross-examination, Dr. Vander Weide agreed that the same model should be used for Citizens and CP&L although, of course, he continued to assert that the model used should be his quarterly model rather than the annual model adopted by the Commission in past cases. Further, on cross-examination by the Attorney General, Dr. Vander Weide testified that he had not seen any order where the FCC had adopted the quarterly DCF and he stated that the Federal Energy Regulatory Commission (FERC) had explicitly rejected it. In fact, Dr. Vander Weide stated that the Illinois' Commission was the only state jurisdiction that he knew which had explicitly adopted the quarterly DCF model.

In regard to flotation costs, on cross-examination, Dr. Vander Weide testified that Citizens had not incurred any flotation costs during the test year, had incurred none since the last case and did not know when Citizens had last issued common stock.

In regard to his adjustment for the "cellular phenomenon", Dr. Vander Weide was cross-examined about whether he thought a statement taken from a Value Line Report dated October 19, 1990, which stated that "Contributions from Bell South cellular unit should make a greater impact on the bottom line" indicated that the forecaster had taken notice of the impact of cellular. Dr. Vander Weide responded that he did not think so within the context of the DCF model. In Dr. Vander Weide's opinion, if an analyst is forecasting five years out the growth rate for Bell South, and there is one item that represents a very small percentage of their total earnings (cellular operations), then in forecasting the total earnings, even if the very small item were to grow quite rapidly, because it is such a small part of the total base, it could not possibly have a significant impact on the growth rate of all of Bell South's earnings over this five-year period and yet it has a very significant impact on the Bell South stock price. However, Dr. Vander Weide further stated that this doesn't hold true beyond the five-year period because once the base of the cellular earnings builds up, then even a smaller cellular growth rate will begin to impact the total growth rate because it starts from a larger base.

The Attorney General, in its proposed order, stated that the rate of return recommendations of both the Company's witness and the Public Staff's witness are inflated beyond the cost of capital for the Company. In the Attorney General's opinion, the recommendations on common equity returns should be adjusted downward to reflect the Company's status as a closely held corporation largely funded by retained earnings and below market rate RTB loans.

The determination of the fair rate of return for the Company is of great importance and must be made with great care because whatever return is allowed will have an immediate impact on the Company, its stockholders, and its customers. In the final analysis, the determination of a fair rate of return must be made by this Commission, using its own impartial judgment and guided by the testimony of expert witnesses and other evidence of record. Whatever return is allowed must balance the interests of the ratepayers and investors and meet the test set forth in G.S. 62-133(b)(4) to

> enable the public utility by sound management to produce a fair profit for its shareholders, considering changing economic conditions and other factors, as they then exist, to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and to compete in the market for capital funds on terms which are reasonable and which are fair to its existing investors.

The return allowed must not burden ratepayers any more than is necessary for the utility to continue to provide adequate service. The North Carolina Supreme Court has stated that the history of G.S. 62-133(b)

> supports the inference that the Legislature intended for the Commission to fix rates as low as may be reasonably consistent with the requirements of the Due Process Clause of the Fourteenth Amendment to the Constitution of the United States....

State ex rel. Utilities Comm. v. Duke Power Co., 285 N.C. 377, 388, 206 S.E. 2d 269 (1974).

The Commission is mindful of the fact that its determination of the appropriate rate of return must be based upon specific findings showing what effect it gave to particular factors in reaching its decision. State ex rel. Utilities Commission v. Public Staff, 322 N.C. 689, 699, 370 S.E. 2d 567, 573 (1988).

The Commission has considered carefully all of the relevant evidence presented in this case, with the constant reminder that whatever return is allowed will have an immediate impact on the Company, its stockholders, and its customers and that the Commission must use its impartial judgment to ensure that all parties involved are treated fairly and equitably.

Based upon the evidence, the Commission believes that the annual DCF model should be given the greatest weight for purposes of determining the cost of equity capital in this case and only minimal weight should be given to the risk premium method, which covered economic conditions spanning over the period of time from 1937 to 1989. The Commission believes it is more appropriate to gauge current investor expectations by considering what investors are currently paying to own utility common stock.

The DCF models used by the two witnesses differed in three major respects: the use of an annual versus quarterly DCF model, the propriety of an adjustment for flotation costs and market pressure, and the propriety of an adjustment for the "cellular phenomenon."

Annual Versus Quarterly DCF Model

Witness Hinton used an annual DCF model, while Dr. Vander Weide used a quarterly model. The Commission has had occasion to consider the quarterly versus the annual DCF model in the past. The Commission in this proceeding has taken judicial notice of the Commission's Order in Docket E-2, Sub 537, the most recent general rate case proceeding for CP&L, which speaks directly to the issue of an annual DCF versus a quarterly DCF. This Order will be quoted at length since what it says applies with equal force to the case at hand. (References are to the record in Docket No. E-2, Sub 537).

> First, we must consider that the discounted cash flow model is intended to estimate investors' expected return on equity. Thus we must ask which of the two versions of the model comes closest to what investors would use themselves. Clearly, the annual version of the model is computationally easier to use. The version of the model used by Dr. Vander Weide as shown on page 22 of his testimony requires that the estimate of the cost of equity be found using a sophisticated iterative procedure. (Tr. Vol. 22, p. 153). The Commission believes that it is highly doubtful that investors actually use this version of the model. Further, it was pointed out during Dr. Vander Weide's cross-examination that published DCF estimates available to investors frequently use the annual version of the model. (Tr. Vol. 22, p.153). To the extent that investors are influenced by these estimates or implicitly adopt them as their own is evidence that the annual version of the model forms the basis of these estimates. Dr. Vander Weide believes that investors use the quarterly model, but offered no direct support for his position other than to argue that if investors did not use the quarterly version of the model there would be arbitrage opportunities around ex-dividend dates and no such opportunities have been observed. Studies may not have observed these opportunities, but they may exist. (Tr. Vol. 22, p. 155). We would not conclude, however, that if they are observed that this necessarily means that investors are using the annual version of the model.
>
> Most importantly, however, dividends that are reinvested during the year will earn a return thereby increasing the annual return to the investor. Moreover there is no requirement that utility stock investors reinvest their dividends in the common stock of the utility. Alternatively, they may be reinvested elsewhere such as in a bank. Since these reinvested dividends, whether invested internally or externally, would earn a return, clearly it is not necessary that utility ratepayers provide an additional return on such funds.

On cross examination in this case, Dr. Vander Weide agreed that the same DCF model should be used for Citizens as CP&L, although, of course, he continued to assert that the model used should be his quarterly model rather than the annual model adopted by the Commission. The Commission finds that the reasoning in the CP&L case holds in this case and that the annual model should be employed.

Flotation Costs and Market Pressure

Dr. Vander Weide adjusted the stock price used in his DCF model downward to account for actual costs associated with issuing stock and for the presumed price effects of the issuance of new stock. Witness Hinton did not make either a flotation cost or market pressure adjustment.

No evidence was offered by the Company to show any flotation cost or market pressure experienced during the test year or since the Company's last rate case. In fact, no stock was issued by the Company or offered for sale to the public during that period. No evidence of intention to issue or sell stock in the foreseeable future was offered by the Company. Under these circumstances, the Commission again refers to its Order in Docket E-2, Sub 537: "In the absence of plans to issue new common stock in the near term, the Commission concludes that an allowance for flotation cost based upon the evidence of record is not justified for purposes of this proceeding." 94 P.U.R. 4th at 506. Market pressure, if it exists at all, requires the issuance of new equity. The Commission finds that no adjustment for market pressure or flotation costs is appropriate in this case.

The "Cellular Phenomenon"

Witness Vander Weide also adjusted the stock price in his DCF model downward to offset what he described as the "cellular phenomenon." In support of his adjustment, Dr. Vander Weide noted that the Regional Bell Holding companies, which both he and witness Hinton employed as proxies for Citizens, have investments in cellular telephone companies. Dr. Vander Weide asserted that expectations of high earnings from these investments have led to increases in the prices of the stocks of these companies. However, Dr. Vander Weide also insisted that the analysts whose opinions are captured in the estimate of future earnings per share growth reported by Institutional Brokers Estimate System (IBES) did not reflect this expectation in their forecasts.

The Company offered no evidence in support of Dr. Vander Weide's hypothetical "cellular phenomenon." On cross-examination, Dr. Vander Weide read an excerpt from a Value Line Report dated October 19, 1990: "Contributions from Bell South cellular unit should make a greater impact on the bottom line." Although Dr. Vander Weide asserted that no expectation of growth in earnings as a result of cellular investment existed, the Commission cannot join in his reasoning given the excerpt read from the Value Line Report. From the evidence available, the Commission finds that no adjustment is appropriate for the "cellular phenomenon" in this proceeding.

Accordingly, the Commission concludes that the annual DCF model as proposed by the Public Staff is the more appropriate methodology for purposes of this proceeding.

The range on common equity return as calculated by witness Hinton using his annual DCF model was 12.20% to 13.10%. Witness Hinton's recalculation of Dr. Vander Weide's model which reflected Dr. Vander Weide's prices, dividends, and growth factors but removed the effects of the "cellular phenomenon", flotation costs, and quarterly dividends resulted in an indicated cost of equity of 12.50% as calculated on witness Hinton's Exhibit JRH-8. According to witness Vander

Weide, the corrected result of the calculation in Exhibit JRH-8 should have been 12.9% to reflect the next period's dividend, not just the current dividend; such adjustment, in Dr. Vander Weide's opinion, would be consistent with the theory of witness Hinton's annual DCF model. The results of Dr. Vander Weide's risk premium method resulted in a range on common equity of 13.75% to 15.25%. In consideration of these ranges in the cost of common equity capital and based upon our own impartial judgment of the evidence as a whole, the Commission concludes that the proper common equity investor return requirement for purposes of this proceeding is 12.70%. This return requirement falls within the range of reasonableness recommended by Public Staff witness Hinton.

Based upon the Commission's findings with respect to the proper capital structure and the appropriate cost rates for each component of capital reflected in said capital structure, the Commission finds and concludes that the overall fair rate of return that Citizens should be allowed an opportunity to earn on its rate base is 10.11%.

It is well-settled law in this State that it is for the administrative body, in an adjudicatory proceeding, to determine the weight and sufficiency of the evidence and the credibility of the witnesses, to draw inferences from the facts and to appraise conflicting evidence. Commissioner of Insurance v. Rate Bureau, 300 N.C. 381, 269 S.E. 2d 547 (1980). State ex rel. Utilities Commission v. Duke Power Company, 305 N.C. 1, 287 S.E. 2d 786 (1982). The Commission has followed these principles in good faith in exercising its impartial judgment in determining the fair and reasonable rate of return in this proceeding. The determination of the appropriate rate of return is not a mechanical process and can only be made after a study of the evidence based upon careful consideration of a number of different methodologies weighed and tempered by the Commission's impartial judgment. The determination of rate of return in one case is not res judicata in succeeding cases. Utilities Commission v. Power Company, 285 N.C. 377, 395 (1974). The proper rate of return on common equity is "essentially a matter of judgment based on a number of factual considerations which vary from case to case." Utilities Commission v. Public Staff, 322 N.C. 689, 694, 370 S.E. 2d 567, 570 (1988). Thus, the determination must be made based on the evidence presented (and the weight and credibility thereof) in each case.

The Commission cannot guarantee that Citizens will, in fact, achieve the levels of return on rate base and common equity herein found to be just and reasonable. Indeed, the Commission would not guarantee the authorized rates of return even if it could. Such a guarantee would remove necessary incentives for the Company to achieve the utmost in operational and managerial efficiency. The Commission finds, and thus concludes, that the rates of return approved herein will afford the Company a reasonable opportunity to earn a reasonable return for its stockholder while providing adequate and economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 14

The evidence in support of this finding of fact is found in the testimony of Company witnesses Pickelsimer, Mottern, Vander Weide, and Wiltsee, and Public Staff witnesses Clapp, Garrison, Sutton, Willis, and Hinton.

Based upon the rate base, operating revenues, expenses and rates of return as previously determined and set forth in this Order, the Commission finds that the Company should be allowed an increase in its gross local service revenues of $331,501. This increase will allow the Company the opportunity to earn the 12.70% return on common equity which the Commission finds to be reasonable.

The following schedules summarize the gross revenues and rate of return the Company should have a reasonable opportunity to achieve based upon the increase approved herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings and conclusions heretofore and hereinafter found reasonable by the Commission.

SCHEDULE I
CITIZENS TELEPHONE COMPANY
North Carolina Intrastate Operations
Docket No. P-12, Sub 89
STATEMENT OF NET OPERATING INCOME
Twelve Months Ended December 31, 1989

Item	Present Rates	Approved Increase	Approved Rates
Operating revenues:			
Local service	$2,551,022	$331,501	$2,882,523
Network access	794,671	-	794,671
Message toll	1,692,827	-	1,692,827
Miscellaneous	847,676	-	847,676
Uncollectibles	(1,531)	(199)	(1,730)
Total operating revenues	5,884,665	331,302	6,215,967
Operating expenses:			
General support	369,748	-	369,748
Central office switching and transmission	304,883	-	304,883
Information origination/ termination	39,579	-	39,579
Cable and wire facilities	686,322	-	686,322
Network operations	226,283	-	226,283
Depreciation and amortization	1,293,787	-	1,293,787
Services	603,081	-	603,081
Executive and planning	182,138	-	182,138
General and administrative	409,474	-	409,474
Interest on customer deposits	1,732	-	1,732
Total operating expenses	4,117,027	-	4,117,027
Operating Taxes:			
Gross receipts	82,094	10,668	92,762
Other taxes	121,788	398	122,186
State income tax	62,087	22,417	84,504
Federal income tax	167,298	101,258	268,556
Total operating taxes	433,267	134,741	568,008
Total operating expenses and taxes	4,550,294	134,741	4,685,035
Net operating income	1,334,371	196,561	1,530,932
Income effect of other adjustments	23,158	-	23,158
Net operating income for a return	$1,357,529	$ 196,561	$1,554,090

SCHEDULE II
CITIZENS TELEPHONE COMPANY
North Carolina Intrastate operations
Docket No. P-12, Sub 89
STATEMENT OF RATE BASE AND RATE OF RETURN
Twelve Months Ended December 31, 1989

Item	Amount
Telephone plant in service	$24,278,373
Accumulated depreciation reserve	(6,556,926)
Net telephone plant	17,721,447
Working Capital:	
Cash	235,270
Materials and supplies	150,351
Prepayments	12,400
Average tax accruals	(199,644)
Customer deposits	(21,678)
Total working capital	176,699
Accumulated deferred income taxes	(2,812,124)
Pre-1971 investment tax credit	(6,304)
Investment in RTB stock	371,594
Unamortized CPE gain	(83,523)
Original cost rate base	$ 15,367,789
Rates of return	
Present rates	8.83%
Proposed rates	10.11%

SCHEDULE III
CITIZENS TELEPHONE COMPANY
North Carolina Intrastate Operations
Docket No. P-12, Sub 89
STATEMENT OF CAPITALIZATION AND RELATED COSTS
Twelve Months Ended December 31, 1989

Item	Capital-ization Ratio	Original Cost Rate Base	Embedded Cost	Net Operating Income
	Present Rates - Original Cost Rate Base			
Long-term debt	55.05%	$ 8,459,968	8.00%	$ 676,797
Common equity	44.95%	6,907,821	9.85%	680,732
Total	100.00%	$15,367,789	-	$1,357,529
	Approved Rates - Original Cost Rate Base			
Long-term debt	55.05%	$ 8,459,968	8.00%	$ 676,797
Common equity	44.95%	6,907,821	12.70%	877,293
Total	100.00%	$15,367,789	-	$1,554,090

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 15

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Pickelsimer and Public Staff witness Lenz.

The Company proposed a number of changes in rates with which the Public Staff disagreed.

Specifically, the Public Staff recommended that the nonrecurring maintenance of service charge (service trip) and the other nonrecurring service charges except the primary service order charge be raised to Southern Bell's levels. Witness Lenz recommended that the returned check charge be increased to $15.00, the maximum allowed by law. On its nonrecurring rearrangement of drop charge, the Company proposed to increase this charge from $4.95 to $35.00. Witness Lenz testified that this charge was already the highest in the state and recommended that this charge only be increased by 10%.

For recurring charges, witness Lenz recommended that the Company's proposals be adopted for the local-call-paystation charge, and directory listings except for a non-listed number. In this regard, she proposed that the non-listed number charge be raised to $1.25 rather than the $1.50 rate proposed by the Company for both non-listed numbers and non-published numbers. Such treatment, in witness Lenz' opinion, would recognize that a non-published number is more valuable to the consumer than a non-listed number. Additionally, witness Lenz recommended that there be no increase in touch tone rates and the rotary line rate be set at 50% of the one-party rate. Witness Lenz recommended that the Company's charges for toll restriction, subscriber transfer, local private line mileage, extension line mileage, custom calling services, paystation-unit type and paystation-inside type be increased by 10% with the rest of the Public Staff's proposed increase being obtained from basic rates.

For local exchange rate relationships, witness Lenz agreed with the Company's proposed 1 to 1 relationship between business one-party and the key trunk rate. For the ratio between business and residence one-party rates, witness Lenz recommended that it be set at 2.5 to 1, and for the ratio between the public telephone access rate and the business one-party rate she recommended 0.7 to 1. The Public Staff recommended that all other local exchange rate relationships remain at their current levels.

Citizens did not object to the changes suggested by the Public Staff except in respect to the overall increase in basic rates and therefore the Commission finds and concludes that the Public Staff's proposals are reasonable up to the point of what the residual revenue increase should be on access line charges and those rates which are multiples of the access line charge.

The residual amount which will be the difference between the increases in revenues produced by the specific rates recommended by the Public Staff and agreed to by the Company and the Commission's revenue increase of $331,501, shall be spread over the Company's access line charges and those rates which are multiples of the access line charge, in accordance with the appropriate rate pricing relationships.

Based upon the preceding conclusions on rate design and other findings in this Order, the Commission finds that the rates and charges which are just and reasonable are the rates and charges itemized in Appendix A attached hereto.

IT IS, THEREFORE, ORDERED as follows:

1. That the Applicant, Citizens Telephone Company, be, and hereby is, authorized to increase its local service rates and charges so as to produce an increase of $331,501 above the level of revenue that would have resulted from rates currently in effect, based on the test year level of operations.

2. That the Applicant is required to file modified tariff sheets prepared pursuant to this Order and to the guidelines contained in Appendix A within 10 days from the date of this Order.

3. That the rates, charges and regulations necessary to produce the additional revenues authorized herein shall become effective upon the filing of the modified tariffs and the approval thereof by the Commission.

4. That the Applicant shall give notice of the rate increase approved herein to each of its North Carolina customers during the next billing cycle following the filing and acceptance of the tariff sheets described in Ordering Paragraph No. 2 above. The Company shall submit its proposed customer notice to the Commission for approval prior to the notice being mailed out to the customers.

ISSUED BY ORDER OF THE COMMISSION.
This the 26th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

APPENDIX A

CITIZENS TELEPHONE COMPANY
DOCKET NO. P-12, SUB 89

Category of Service	Monthly Rate Per Unit
RESIDENCE	
Access Line Charge	$10.71
Tone Dial Access	$ 1.36
Rotary Line Service	$ 5.35
Three Way Calling	$ 3.20
Call Forwarding	$ 2.13
Call Waiting	$ 3.20
Speed Call 8	$ 2.13
Speed Call 30	$ 3.58
Call Forward/Call Wait	$ 4.81
Speed Call 8/Call Waiting	$ 4.81
Call Forward/Waiting/Speed 30	$ 8.55
Call Forward/Waiting/Speed 8	$ 5.98
All Features Except 30 Code	$ 8.02

TELEPHONE - RATES

BUSINESS	
Access Line Charge	$26.76
Tone Dial Access	$ 1.80
Call Waiting	$ 5.35
Call Forwarding	$ 3.20
Speed Call 8	$ 3.20
Three Way Calling	$ 4.28
Rotary Line Service	$13.38
Speed Call 30	$ 5.03
PBX Trunk Rate	$53.53
PBX Trunk-Inward Only	$53.53
PBX Trunk-Outward Only	$53.53
PBX Trunk-DID w/SLI	$31.10
PBX Trunk	$42.82
Key Trunk Rate	$26.76
Public Telephone Access	$18.73
Access Line Charge-Paystation	$40.15
Paystation-Unit Type	$ 1.61
Paystation-Inside Type	$ 5.35
MISCELLANEOUS	
Extension Line Mileage	$ 1.12
Local Private Line Mileage	$10.68
Toll Restriction	$ 3.20
Subscriber Transfer	$ 4.60
Listing-Non Listed	$ 1.25
Listing-Non Published	$ 1.50
Listing-AL	$ 0.75
Local Call-Paystations	$ 0.25

Category of Service	Nonrecurring Charge
RESIDENCE	
Primary Service Order	$27.50
Secondary Service Order	$10.75
Premise Visit	$10.25
Central Office Work	$15.25
BUSINESS	
Primary Service Order	$41.25
Secondary Service Order	$14.50
Premise Visit	$10.25
Central Office Work	$21.25
MISCELLANEOUS	
Returned Check Charge	$15.00
Service Trips	$31.25
Rearrangement of Drops	$ 5.45

DOCKET NO. P-140, SUB 29

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Tariff Filing by AT&T Communications of the Southern States, Inc., to Revise Its Series 2000 Private Line Rates)	ORDER ALLOWING INCREASES AND SETTING OUT CONDITIONS

HEARD IN: Commission Hearing Room, Dobbs Building, Raleigh, North Carolina on May 14, 1991.

BEFORE: Commissioner Sarah Lindsay Tate, Presiding; and Chairman William W. Redman, Jr., and Commissioner Laurence A. Cobb

APPEARANCES:

For AT&T Communications:

William A. Davis, II, Tharrington, Smith, & Hargrove, Attorneys at Law, Post Office Box 1151, 209 Fayetteville Street Mall, Raleigh, North Carolina 27601

and

Gene V. Coker, AT&T Communications, 1200 Peachtree Street, N.E., Atlanta, Georgia 30067

For Carolina Utility Customers Association, Inc.:

Samuel J. Ervin, IV, Byrd, Byrd, Ervin, Whisnant, McMahon & Ervin, P. A., Post Office Drawer 1269, Morganton, North Carolina 28655

For the Attorney General of North Carolina:

Karen E. Long, Assistant Attorney General, North Carolina Department of Justice, P. O. Box 629, Raleigh, North Carolina 27602

For the Public Staff:

Antoinette R. Wike, Chief Counsel, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On September 28, 1990, AT&T Communications of the Southern States, Inc. (AT&T), filed tariffs to increase the rates for its Series 2000 voice grade and foreign exchange station terminals as well as to reduce the rates for the zone charges associated with these station terminals. The tariffs had a proposed effective date of December 14, 1990.

This matter was initially considered by the Commission at its Regular Commission Conference on December 3, 1990. At that time, the Public Staff recommended that the tariff filing be declared a general rate case rather than a complaint proceeding since the proposal would substantially increase AT&T's return on equity and there were offsetting rate reductions for other services. The Public Staff also requested that the proposed tariffs be suspended, that the filing be set for hearing with adequate notice to affected subscribers, and that AT&T be required to comply with the minimum filing requirements for a general rate case to justify the need for additional revenue. Furthermore, the Public Staff asked that AT&T be required to justify the elimination of the points of presence (POPs) with voice grade and foreign exchange capabilities.

By order issued December 11, 1990, the Commission suspended the tariff filing pending investigation.

On February 11, 1991, the Commission issued an order setting a hearing date and, pursuant to G.S. 62-137, declaring the scope of the hearing to be a complaint proceeding rather than a general rate case. That order identified three areas to be addressed at the hearing:

1. whether the proposed increases are justified by the 1988 special access charge increases;

2. whether it would be reasonable to consider a "flow-through" of any rate increases granted in this docket; and

3. the customer impact resulting from the elimination of certain points of presence.

Additionally, the Commission directed AT&T to file a schedule of proposed rates reflecting a flow-through or offset of the proposed private line rate increase. On March 15, 1991, AT&T filed a motion for clarification requesting the Commission to specify that the time for filing proposed flow-through rates would be deferred pending the hearing and a determination regarding the need for offsetting rate reductions. By order issued April 10, 1991, the Commission granted AT&T's request and stated that AT&T should file a statement indicating general areas of services in which it would file rate reductions should the need for such reductions be determined. AT&T filed such a statement on May 13, 1991.

In ordering paragraph 4 of its February 11, 1991, order, the Commission required AT&T to prepare a notice to affected subscribers and to submit a copy to the Commission and the Public Staff for review. AT&T submitted such a notice on February 26, 1991, and on February 27, 1991, the Commission issued an order approving the notice.

On April 4, 1991, the Carolina Utility Customers Association, Inc. (CUCA) filed a petition to intervene in the proceeding. This petition was granted by order issued April 5, 1991.

The matter came on for hearing as scheduled. Eric Prevatte, owner of Prevatte Auto Parts, and Randy Lisk, Executive Vice President of the North Carolina Automotive Wholesalers Association, testified as public witnesses. AT&T presented the direct and rebuttal testimony and exhibits of Roger L. Walter, a

District Manager for Government Affairs. The Public Staff presented the testimony and exhibits of John T. Garrison, Jr., an Engineer in the Communications Division.

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

FINDINGS OF FACT

1. AT&T is a public utility duly authorized to do business in North Carolina. AT&T is providing intrastate telecommunications service in North Carolina and is subject to the jurisdiction of this Commission. AT&T is properly before the Commission in this proceeding for a determination of the justness and reasonableness of its proposed rates and charges.

2. AT&T can provide analog private line service from one of two tariffs: its Series 2000 tariff, which was adopted at divestiture and restructured in 1988, and as an option of its ACCUNET Spectrum of Digital Services (ASDS) tariff, which became effective in February of this year. Series 2000 service has traditionally been used to provide analog private line services such as voice grade (VG) private line service and foreign exchange (FX) service.

3. The demand for Series 2000 service is declining. AT&T's goal is to move all customers from its Series 2000 tariff to its ASDS tariff.

4. AT&T's original proposal was to increase the station terminal rates associated with its Series 2000 VG and FX services, to make changes in zone assignments of local exchange company (LEC) serving offices to reflect the elimination of VG and FX capability at certain POPs, and to reduce zone mileage rates. The effect of all of these changes would have been a revenue increase of $1.6 million and a 305 basis point increase in AT&T's return on equity based on its NCUC Form T.S.-1 for 1988.

5. AT&T now proposes to mitigate the proposed rate changes by increasing only the station terminal rates and making no changes to zone rates or assignments, but obsoleting the tariff and allowing no additions or reconfigurations under it. AT&T further proposes to convert customers served under the Series 2000 tariff to the ASDS tariff rates in six-month steps from February 1, 1992, to August 1, 1993.

6. AT&T's current station terminal rates for Series 2000 VG and FX private line service do not fully cover the station terminal components of the special access rates charged by the local distribution companies. The proposed station terminal rates are in line with changes to the special access rates that have occurred since AT&T's private line rates were last restructured.

7. The proposed increases in station terminal rates will have widely varying customer impacts, with some increases exceeding 50%.

8. Customers who subscribe to Series 2000 VG service use it to communicate on a point-to-point basis between two or more locations. Customers who subscribe to Series 2000 FX service use it to enable communications between a subscriber

location in one local calling area and all of the subscribers in a distant local calling area.

9. With the proposed station terminal rates, the rate versus cost relationship for Series 2000 service will be improved. The declining demand for Series 2000 service will keep any disparity between revenues and costs from worsening, even if existing customers are permitted to add or rearrange service.

10. The benefits of converting Series 2000 customers to ASDS service are (a) to simplify service ordering and provisioning; (b) to eliminate many manual paper processing functions; (c) to reduce the incentive of customers to tariff shop between jurisdictions; and (d) to enable customers to compare prices with other interexchange carriers more directly.

11. Series 1000 services were obsoleted by the Commission in AT&T's 1988 restructure of private line services, with existing customers being permitted to add or rearrange service.

12. The proposed increases in station terminal rates will increase AT&T's overall revenues by approximately $1.375 million.

13. A $1.375 million increase in revenue will cause a 261 basis point increase in AT&T's return on equity based on its NCUC FORM T.S.-1 for 1988.

14. The 1988 restructure of private line rates was accompanied by a reduction in rates for AT&T's switched services in an amount equal to the net revenue increase of the private line restructuring. The increases resulting from the private line restructure were phased in, with the final rates becoming effective in 1989. The offsetting reduction in rates for AT&T's switched services became effective in 1988.

15. AT&T has experienced reductions in rates it pays for switched access totalling approximately $15.51 million since July 1, 1988, when the rates it pays for special access were increased. During this time, AT&T has decreased its rates for switched services by only $9.16 million, not counting any temporary promotions, reductions for tax expense changes, or offsets for revenue increases in other services.

DISCUSSION OF EVIDENCE

Customer Impact

Mr. Prevatte testified that he owns three auto parts stores -- a main operation in Lumberton where the data processor is located and branch stores in Pembroke and St. Pauls that are on private lines operating off of the same processor. He had initially thought that his cost of private line service between Lumberton and St. Pauls, which is carried by AT&T, Southern Bell, and Carolina Telephone, was going to increase from $428 to $661 per month. He later learned that he would receive a decrease to $398 per month. (His monthly cost increased from $193 to $428 when AT&T's private line rates were restructured.) His private line service between Lumberton and Pembroke, which is provided by Southern Bell, costs approximately $185 per month for the same geographic distance. Mr. Prevatte further testified that his alternatives to service from

AT&T were either a stand-alone unit in the branch stores that would access the data processor with a dial-up modem for one-time transmission or service from other carriers at an even higher cost.

Mr. Lisk testified that his organization has 466 jobber and warehouse distributor members, most of which are small businesses and many of which are located in rural areas, such as Toast and Vass. Like Mr. Prevatte, he complained about inefficient routing of certain lines which, he said, puts businesses in small rural communities at a competitive disadvantage with larger businesses.

Mr. Walter testified that AT&T's original proposal represented an average price increase of 16%, with some customers experiencing decreases and others experiencing increases of 50% or more. He stated that AT&T's present and proposed private line rates are below MCI's but above SouthernNet's, indicating that customers choose their interLATA carrier based on a variety of factors and that they have a range of viable alternatives available to them. He further stated that, for most applications, customers have the additional choice of using a switched service. He conceded, on cross-examination, that private line service and WATS service are not directly equivalent because private line service is tailored mostly for point-to-point or multipoint communication rather than for broad calling areas.

Mr. Walter also testified that the true percentage impact of a rate increase for any customer is a function of the total telecommunications bill and not just the cost of private line service, noting that business long distance rates have decreased by 9.5% since July 1, 1988. He agreed, on cross-examination, that the validity of this assertion is going to vary depending upon the customer's bill and the components of service they purchase. Finally, Mr. Walter testified that it has been three years since the last private line rate increase and that AT&T's Series 2000 customers have been notified three times of the proposed increase, giving them ample time to plan or to seek alternatives.

Mr. Walter testified that AT&T is eliminating Series 2000 service across the nation and that customers are being converted to ASDS service. Ten states have already converted to ASDS service, while nine others have approved plans to do so. According to Mr. Walter, the benefits of converting to ASDS include the simplification of service ordering and provisioning and the elimination of many manual paper-oriented processing functions. He also stated that converting to ASDS service will reduce the incentive for customers to tariff shop between state and interstate tariffs. Another benefit of converting Series 2000 customers to ASDS service, mentioned by Mr. Walter, is the ease of comparing prices with other interexchange carriers.

On cross-examination, Mr. Walter stated that the second alternative proposal put forth by AT&T was probably the best plan. Under this plan, which was spelled out in Mr. Walter's rebuttal testimony, the station terminal rates would increase effective August 1, 1991, but no change in zone rates would be made and no elimination of POPs would be reflected. Series 2000 service would be obsoleted, with no rearrangements allowed and any additions to existing circuits as well as all new circuits being priced using ASDS rates. Between August 1, 1991, and February 1, 1992, customer bills would be recalculated based on the current ASDS rates. A credit would be issued based on the difference between the ASDS rates and the Series 2000 rates. On February 1, 1992, the credit would be reduced to

75% of its original level; on August 1, 1992, it would be reduced to one half of its original level; and on February 1, 1993, it would be reduced to 25% of its original level. Finally, on August 1, 1993, the credit would be eliminated entirely, and customers would begin paying the full ASDS rates.

Mr. Garrison testified that specific customer impacts of AT&T's proposals varied widely. Although the increase in revenues is only 14%, increasing the station terminal rates would produce the customer impacts shown below:

Price Change	Percent of Customers
Decreases over 20%	0.0%
Decreases 0% to 20%	2.8%
Increases 0+% to 10%	19.5%
Increases 10+% to 20%	72.8%
Increases 20+% to 30%	3.0%
Increases 30+% to 50%	0.8%
Increases over 50%	1.1%

He further testified that many of the customers who will be adversely affected by the proposed rate changes were also impacted by the 1988 private line restructure, in which some received increases exceeding 50%. There was no evidence on the range of customer impacts if AT&T were permitted to eliminate Series 2000 service and require customers to subscribe to analog private line service through AT&T's ASDS tariff. However, Mr. Garrison testified that the average customer would receive over an 80% increase in rates by going from the current Series 2000 service to ASDS service.

Mr. Garrison also stated that the conditions proposed by AT&T for obsoleting its Series 2000 VG and FX services are too strict. The Public Staff believes that existing customers should be permitted to add or rearrange service and should not be required to convert to AT&T's new ASDS service. According to Mr. Garrison, Series 2000 VG and FX services are already on the decline. If the services are obsoleted, no new customers will be permitted to take the offering, which, he said, should accelerate the decline.

Mr. Garrison testified to the manner in which AT&T should offer the obsoleted Series 2000 service. He recommended that customers be permitted to rearrange or add to existing circuits as was done in AT&T's restructure of private line rates in 1988. At that time, Series 1000 service was obsoleted and existing Series 1000 customers were permitted to rearrange or add to existing circuits.

Costs

Mr. Walter testified that AT&T's station terminal rates are 51% below the level necessary to recover its cost of obtaining special access from the LECs and, as a result, AT&T experiences an annual shortfall of $2 million in special access recovery. He further testified that, contrary to AT&T's and the Commission's initial belief, the July 1. 1988, special access increase was not totally offset by the reduction in switched access that occurred at the same time. He stated, on cross-examination, that AT&T's POP consolidation program had resulted in some reduction in the cost of providing private line service. Mr.

Garrison testified that he had reviewed the workpapers of AT&T and the LECs in connection with the access charges effective July 1, 1988, as well as the changes proposed by Southern Bell in Docket No. P-100, Sub 112, and determined that the increases proposed by AT&T for its Series 2000 VG and FX services are in line with the changes that have occurred since AT&T's private line rates were restructured.

Revenues

Mr. Walter testified that AT&T's original proposal would have produced additional revenues of $1.6 million, while its proposal to increase only the station terminal rates would produce $1.375 million. He further testified, on cross-examination, that, if all of AT&T's Series 2000 customers immediately switched to ASDS, its revenues would increase by $8 million. He did not know the revenue impact of the proposed two-year ASDS conversion.

Offsets

Mr. Walter testified that AT&T had not sought the proposed increase in private line rates until now for several reasons: from September 1988 through November 1, 1989, its efforts were focused on filings for Series 1000 and 5000 because the Commission had not granted AT&T's full request in 1988 but had ordered a phased approach for these two series; it did file a similar proposal for Series 2000 in April 1990 but withdrew the filing after discussions with the Public Staff. Mr. Walter further testified that, since April 1990, AT&T has filed and implemented rate reductions for business switched services totalling $1,788,800.

Mr. Garrison testified that AT&T had made no attempt to justify an increase in the rate of return for its North Carolina operations. He further testified that, since July 1, 1988, the Commission has ordered reductions in switched access charges which have lowered AT&T's costs by about $15.51 million ($10.52 million on July 1, 19189, and $4.99 million on July 1, 1990). During this period, however, AT&T has reduced the rates for its switched services by only about $9.16 million on an ongoing basis. He stated, on cross-examination, that the Public Staff does not have information that shows AT&T's North Carolina operating results. Therefore, the Public Staff does not know the level of AT&T's intrastate earnings. He also stated that his testimony did not attempt to address changes in volumes or in the mix of services over time, adding that this would be a rate case matter. He conceded that, if AT&T had held up on the $1.8 million in rate reductions since April 1990 and filed them in conjunction with the private line filing, the Public Staff more than likely would have considered that a revenue neutral filing, even though, as a technical matter, AT&T could turn around and raise those rates to pre-existing levels without violating the ceiling rate plan. If AT&T did that, however, and then reduced the rates in the same filing as the private line increase, the Public Staff might not consider the filing to be revenue neutral. Nor, he said, would the Public Staff fail to look behind a simultaneous and offsetting reduction in rates not subject to a cap, which had just been increased by the amount of the offset. On redirect examination, Mr. Garrison stated that the appropriate forum in which to take into account all of the changes in revenues and costs that AT&T has experienced since 1988 is a general rate case.

In rebuttal, Mr. Walter stated that Mr. Garrison's analysis failed to take into account that switched access rates implemented on July 1, 1988, were greater than originally planned and that AT&T was not awarded the full private line rate increase on September 30, 1988. He further stated that Mr. Garrison ignored a $5.44 million promotional offering last fall. In addition, Mr. Walter stated that an analysis of AT&T's switched services revenue, access, and volumes for 1987 through 1990 shows that total dollars retained by AT&T, net of access paid, have decreased from $115 million to $109 million and that, while access has declined by $0.23 per minute, revenues per minute have decreased by $.013. This decline in revenue retained per minute, he said, is equivalent to AT&T flowing through to its customers $17 million per year more than the access reductions it has received. As to whether he was saying that AT&T's overall level of earnings had decreased during this period, Mr. Walters stated, on cross-examination, that he had no specific knowledge of earnings. He further stated that over the past two or three years AT&T has not been working under a mentality of flowing through but has been responding to competition and that, in a competitive environment, AT&T might reduce its prices to reflect reductions in other costs or simply reduce its profits.

CONCLUSIONS

Increasing Station Terminal Rates

Both AT&T and the Public Staff have recommended that the station terminal rates for Series 2000 service be increased. The Attorney General and CUCA indicated support for this increase. The basis for this recommendation is to better enable AT&T to recover the access costs associated with the service. The Commission therefore concludes that the station terminal rates should be increased as proposed by AT&T and the Public Staff.

Obsoleting Series 2000 Services

AT&T proposes that its Series 2000 services be obsoleted, with the customers being converted to its ASDS service within a certain time frame. The Public Staff recommends that the Series 2000 services be obsoleted but that current customers be permitted to maintain services until they determine that another offering is better suited to their needs. The Attorney General agreed with the Public Staff's position. The Commission concludes that Series 2000 services should be obsoleted. The Commission is of the opinion, however, that current customers should not be required to convert to ASDS service as proposed by AT&T.

The private line restructure approved by the Commission in 1988 caused significant increases to many of these customers. The increase in station terminal rates recommended by both AT&T and the Public Staff in this docket will result in further significant increases. Regardless of the revenues that would ultimately accrue to AT&T if it converted its Series 2000 customers to ASDS service over a period of time, the average customer would see his rates increased by 80% at the end of the conversion process. It would be unreasonable to allow AT&T to increase customer bills by this amount for the purpose of enabling AT&T to achieve billing economies and to provide a rate structure similar to that of other interexchange carriers.

The Commission believes that the decline in services will eventually produce the result desired by AT&T, which is elimination of Series 2000 services. The evidence shows that the demand for Series 2000 service is declining. When the service is obsoleted, this decline should be more dramatic. The Commission is of the opinion, however, that the existing customers should be allowed to stop using the services at their own pace.

AT&T and the other parties also disagreed on the conditions under which Series 2000 services should be obsoleted. AT&T insists that no service rearrangements or additions to existing circuits be permitted, while the Public Staff, Attorney General, and CUCA believed that such rearrangements and additions should be allowed. The Commission is persuaded that, particularly in the case of new circuits, the proposal of the Public Staff would be unduly discriminatory. If existing customers are permitted to add new circuits under the old tariff but future customers may only subscribe to the ASDS tariff, customers in equivalent circumstances would be treated differently. Moreover, under the Public Staff proposal, that situation would last indefinitely. The Commission concludes that the fair and nondiscriminatory solution is to require all new private line circuits to be provided under the ASDS tariff and that expansion of existing service should not be permitted. However, the Commission believes that limited rearrangements of existing service such as moves of existing service within a business location or a change in location of an existing customer should be allowed.

Individual cases may be presented for the Commission's review.

<u>Offsets</u>

The Commission issued an order on August 25, 1987, in Docket No. P-100, Sub 72, revising the capped (then called the ceiling) rate plan which governs tariff filings and rate changes for AT&T and the other interexchange carriers (IXCs) as well as resellers operating in North Carolina. This order provides, in pertinent part, as follows:

> [R]ate treatment as non-general case proceedings involving the situations outlined by AT&T in its comments regarding rate requests which reflect no impact on net income or only reasonable increases in costs or expenses such as taxes, access charges, or inflation as measured by the consumer price index may be reasonable and appropriate. The current statutes give the Commission authority to declare the scope of a proceeding by determining whether it is either a general rate case or a case confined to the reasonableness of a specific single rate, a small part of the rate structure, or some classification of users involving questions which do not require a determination of the entire rate structure and overall rate of return; G.S. 62-137. Thus, the Commission will consider filings of AT&T on a case-by-case basis to determine whether said filings may be handled as a complaint case and thus on a non-general rate case basis.

By order issued August 6, 1990, the Commission further revised the ceiling rate plan to provide, among other things, that AT&T may increase or decrease its rates other than MTS or VG private line rates in the same manner and subject to the same conditions as the other IXCs. The order stated that the Commission is convinced that AT&T's interLATA MTS and voice-grade private line rates should remain subject to the capped rate plan since AT&T continues to be the only long-distance carrier providing those services to all portions of the state and is still the price-setter as a result of its market power. The interests of residential and small business customers continue to warrant the greater protection afforded by the capped rate plan.

There is no question that the proposed increase in station terminal rates for Series 2000 VG and FX private line service is subject to the capped rate plan. The question is how the plan applies to the facts of this case. AT&T's position, as stated in its response to the Public Staff's recommendation at Staff Conference on December 3, 1990, is that this filing qualifies for non-general rate case treatment under the August 25, 1987, order, because it is a pass through of access charges. AT&T further contends that the filing "largely qualifies" for non-rate case treatment because of switched services reductions amounting to $1.3 million that AT&T has made since the April 1990 filing was withdrawn. AT&T's contentions are based on the proposition that the Commission has established two categories of filings that qualify for non-general rate case treatment: (1) filings where proposed increases are offset by rate decreases resulting in a zero impact on earnings, and (2) filings to reflect reasonable increases in certain costs and expenses, including access costs. The Commission finds AT&T's position to be simplistic at best.

Notwithstanding the language of the August 27, 1987, order on which AT&T relies, the essence of a pass through outside a general rate case has always been and remains <u>earnings neutrality</u>. Absent deferral accounting, a pass through occurs contemporaneously with the increase or decrease in cost which occasions it. In this case, the special access charge increase occurred on July 1, 1988, nearly three years ago. Further complicating matters are the changes in switched access charges which occurred at the same time; the impact of these changes on AT&T is not entirely clear. The Commission therefore is of the opinion that a finding of earnings neutrality is no longer possible if indeed it ever was. AT&T would have us find neutrality, however, in the switched service rate reductions that it has made since April 1990 but could have deferred to coincide with and offset the private line rate increase. Again, the Commission is of the opinion that such a finding is impossible given the timing of the reductions in relation to the increases.

The Public Staff maintains that the only way the Commission can ensure earnings neutrality in connection with the $1.375 million in additional revenue to be derived by AT&T from the increase in station terminal rates is to require contemporaneous decreases in rates for other services to produce a reductions in revenue of an equal amount. The Commission agrees. The only alternative is a general rate case in which all of AT&T's revenues and expenses can be brought to an end-of-period level and rates can be set on a going forward basis to enable AT&T to achieve its authorized rate of return. This is the kind of proceeding that AT&T has assiduously sought to avoid, arguing instead that, because of something that happened in 1988, it is entitled to a $1.375 million revenue increase in a complaint proceeding today under the capped rate plan. The Commission never intended for the plan to work this way. We merely recognized that there may be cases involving rate requests by AT&T which, because of their lack of impact on earnings, may be handled as complaint cases rather than as general rate cases. This was the rationale behind the February 11, 1991, order declaring the scope of this proceeding. There we expressed our concern about the reasonableness of the argument that the proposed rate increases were justified by the 1988 access charge increases. We therefore concluded that in order for the matter to be heard as a complaint proceeding, "AT&T should provide the Commission with a schedule of proposed rate decreases to reflect a flow-through of its proposed rate increases which would result in no impact on net income." (emphasis added) This requirement was later deferred pending a determination of the need for offsetting rate reductions. Having now heard all of the evidence, the Commission is of the opinion that offsetting rate reductions flowing through the full amount of the $1.375 million increase are legally and factually required.

AT&T and CUCA believe that any offsets the Commission orders be in the form of reductions in rates to business customers. The Public Staff and the Attorney General, on the other hand, has recommended reductions in rates for services used by residential customers, who have benefitted from less than one-quarter of the permanent rate reductions AT&T has made since 1988. Private line is a business service and the Commission is of the opinion that any offsetting reduction in rates should be applied to business service. Therefore, we will direct AT&T to target the rate reductions to business customers. AT&T should file a schedule of rate reductions to be reviewed by the Public Staff and approved by the Commission. Our decision to require offsets is entirely consistent with Docket No. P-140, Sub 17, the 1988 private line restructure docket, in which AT&T offset the increase in private line revenues with a $1,252,400 reduction in its MTS, ALLPRO WATS, PRO WATS, and Reach Out North Carolina rates.

Therefore, the Commission reaches the following conclusions:

1. The proposed increases in station terminal rates for AT&T's Series 2000 VG and FX services are just and reasonable and should be approved.

2. The proposed conversion of AT&T's Series 2000 VG and FX customers to ASDS service is unjust and unreasonable and should be rejected.

3. AT&T's Series 2000 VG and FX services should be obsoleted as follows:

a. no new customers should be permitted to take the offering;

b. existing customers should be permitted limited rearrangements of service;

c. no date should be set for complete withdrawal of the offering.

3. AT&T should file a schedule to decrease its rates for services used by business customers to offset the $1.375 million revenue impact of the increase in station terminal rates for Series 2000 VG and FX services.

IT IS, THEREFORE, ORDERED as follows:

1. That, in accordance with the findings and conclusions set forth in this order, AT&T file tariffs to

(a) increase the station terminal rates for its Series 2000 services;

(b) obsolete its Series 2000 services; and

(c) reduce rates for its business switched customers.

2. That AT&T file a schedule of reductions and workpapers to support the reduction in rates pursuant to paragraph 1(c) for review by the Public Staff and approval by the Commission.

3. That AT&T prepare for Commission approval a notice to its customers of the increase in station terminal rates for Series 2000 services.

ISSUED BY ORDER OF THE COMMISSION.
This the 19th day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. P-55, SUB 925

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Southern Bell Telephone and Telegraph Company Tariff Filing to Establish Rates and Regulations for Caller ID Service	) ORDER ALLOWING CALLER) ID WITH PER LINE AND) PER CALL BLOCKING

BY THE COMMISSION: On October 20, 1989, Southern Bell Telephone and Telegraph Company (Southern Bell) filed a tariff with the Commission to establish rates and regulations for Caller ID service without blocking. This matter came before the Regular Commission Staff Conference on November 20, 1989. The proposed service provides for the delivery of the telephone number of the calling party to the called party. The originating number will be sent to the Caller ID subscriber during the ringing cycle before the subscriber answers. To interpret the signal provided by Southern Bell, the called party must have a decoding and display device at his premises on his line. As the signal arrives during the first long silent interval in the ringing cycle, the Caller ID subscriber's equipment displays the 10-digit telephone number of the line from which the call was made, the date and the time, providing the subscriber the opportunity to identify who is calling before answering the telephone. Southern Bell's original Caller ID proposal contained no provisions for blocking.

Caller ID would initially be available to subscribers in the Chapel Hill exchange and in exchanges in the Burlington, Charlotte, and Raleigh areas. Identification of the calling numbers would be limited to calls from areas which have been converted to CCS7 signalling. The areas from which calling numbers would be identified would increase as the CCS7 signalling is further developed.

The Public Staff stated that it had reviewed the cost support for the rates, $7.50 per month for residence and $10.00 per month for business, and concluded that the rates are reasonable. The rates were filed under the flexible pricing plan previously allowed by the Commission for other TouchStar services.

The Public Staff identified several areas of concern about Caller ID service which it believed warrants careful consideration prior to a decision by the Commission on the merits of whether to allow implementation of the service. The Public Staff and Attorney General recommended that consumers should be given an opportunity to file written comments prior to a Commission decision on the service.

On November 21, 1989, the Commission issued an Order in this docket suspending Southern Bell's Caller ID service to subscribers by means of bill inserts and newspaper publications. That notice was in fact given by the Company.

The Commission, Public Staff, and Attorney General received a substantial response from the public concerning Caller ID. However, allegations surfaced concerning the actions of certain Southern Bell employees in soliciting or encouraging a letter writing campaign on Caller ID. On April 4, 1990, following numerous filings, the Commission was constrained to issue an Order Regarding Employee Letters Written in Support of Caller ID Service. In that Order, the

Commission stated its opposition to any systematic effort by a public utility to encourage the submission of letters by employees on any matter pending before the Commission without identification of the company's involvement and/or the writer's corporate affiliation. While not questioning employee First Amendment rights, the Commission instructed Southern Bell that if there was such solicitation or encouragement by the Company in the future, it should notify the Commission in writing of this effort.

The Public Staff and Attorney General compiled the public responses they had received and reported the results to the Commission. Of the 1,953 total comments the Public Staff received, 995 or 47.5% opposed it. However, Southern Bell employees accounted for 399 of the comments, 20% of the total and 39.9% of those in favor. Without the Southern Bell comments, 598 or 38.5% supported Caller ID and 926 or 59.6% opposed it. The Attorney General reported that approximately 70% of the 1,317 comments it received were against Caller ID. On March 30, 1990, the Attorney General filed a motion that Caller ID be approved only with free blocking.

This docket again came before the Regular Commission Staff Conference on April 2, 1990. The Public Staff recommended that the proposed tariff be modified to include free optional blocking of calling number delivery in areas in which Caller ID is offered. Jo Anne Sanford of the Attorney General's Office spoke in favor of the Public Staff recommendation. The following persons spoke against Caller ID: Renee Stevens of the North Carolina Coalition Against Domestic Violence; Anne Long, Joanne Parker, and Barbara Wood, all from the Orange-Durham Coalition for Battered Women; Lucinda Drago, Ex-Director, Interact; Genie Creighton, Orange-Durham Coalition for Battered Women; and Karen O'Neill, a HELPLINE staffer.

Al Povall represented Southern Bell. Tom Whitehead of BellSouth Services presented a modification of Southern Bell's original proposal. As revised, blocking of Caller ID would be available to law enforcement agencies and domestic violence agencies. Blocking would be available to individual counseling volunteers as requested by the agency. At the request of the Commission, Southern Bell reduced its proposal to writing in the form of a proposed tariff. The new proposed tariff read as follows with respect to blocking:

> A.13.19.3.A.8. Optional Calling Number Delivery Blocking is available on request, at no charge, to the following entities and their employees/volunteers, for lines over which the official business of the agency is conducted including those at the residences of employees/volunteers where the head of an agency certifies to local company management a need for blocking based upon health and safety concerns: (a) non-profit, tax exempt, private and public social welfare agencies such as domestic violence intervention agencies; (b) federal, state, and local law enforcement agencies.

The following persons appeared to speak in favor of Caller ID: Senator William Goldston of Rockingham County; Representative W. W. Dixon of Gaston County; Representative James A. Pope of Wake County; Dr. Jack N. Drummond, Wayne County Medical Examiner; Paul Daly, an FBI Special Agent, Joseph Pruitt of the North Carolina Police Chiefs Association; Ann Z. Sandler of REACHLINE; and Arthur Griffin of the Charlotte-Mecklenburg School Board.

Since the April 2, 1990, Regular Commission Conference, there have been numerous filings made by the parties: Reply of the Public Staff on April 19, 1990, Response of Southern Bell to Motion of Attorney General for Free Blocking on April 6, 1990; Proposed Amended Tariff of Southern Bell on April 6, 1990; Comments and Renewed Motion by the Attorney General on May 10, 1990; Southern Bell Reply Brief on May 30, 1990; Southern Bell Supplemental Filing of June 6, 1990; Attorney General Opinion Regarding Legality of Caller ID on July 19, 1990; Southern Bell's Reply to the Attorney General on August 3, 1990; the Public Staff's filing of July 26, 1990; and the Attorney General's informational filing on August 9, 1990.

Attorney General's January 3, 1991, Filing and Subsequent Responses

On January 3, 1991, the Attorney General filed a Response and Memorandum. In it, the Attorney General responded to Southern Bell's August 3, 1990, Reply and reiterated its conviction that Caller ID constituted an illegal trap and trace device under North Carolina law. However, the Attorney General also set out several suggestions regarding the possible configuration of such a service, should the Commission not agree with its views on the legality of the service. The Attorney General said that the optimal configuration was "free blocking for all subscribers available through both a per-call and a per-line option." The Attorney General noted that this had been adopted in Alabama (PSC Docket No. 21592, December 4, 1990) and Nevada (PSC Docket No. 90-333, August 20, 1990). A "less acceptable" configuration was as follows:

(1) Optional, free, per-call blocking for all subscribers
(2) Optional, free, per-line blocking for a broad range of public and private agencies (including their employees, volunteers, and clients), subject to a certification of need by the agency head
(3) Special accommodation for law enforcement agencies which demonstrate a specific need due to the sensitive nature of their operations.

On January 29, 1991, the Public Staff filed its comments. The Public Staff recapitulated the arguments of Southern Bell and the Attorney General. The Public Staff recommended a "conservative approach," and stated it "does not object" to the "minimally adequate configuration" referred to by the Attorney General. The Public Staff also advocated the easier and cheaper availability of Call Trace.

On February 15, 1991, Southern Bell filed a reply to the recent filings of the Attorney General and Public Staff. Southern Bell defended the current Call Trace Tariff, which the Commission had allowed to go into effect at its Regular Commission Conference on November 14, 1988, and maintained that Caller ID was legal under G.S. 15A-260 et seq. The Attorney General made a reply to this filing on March 1, 1991, to which Southern Bell replied on March 26, 1991.

Identification of Major Issues

The Caller ID issue is an exceedingly large and complex question that is provoking extensive controversy nationwide. Generally speaking the Caller ID issue can be broken down into two major categories: first, the legal issue and, second, the public policy issues.

The main legal issue is whether Caller ID violates the provisions of the state Pen Register and Trap and Trace Device statute (G.S. 15A-260 et seq). The public policy issues include questions regarding the usefulness of the service; the appropriate extent of blocking; and privacy concerns.

1. Legal issues. On July 19, 1990, the Attorney General submitted an opinion regarding the legality of Caller ID, Response to Southern Bell's filing of June 6, 1990, and Information in Support of Motion for Change in Southern Bell's Call Trace Tariff. The Attorney General concluded that the Caller ID tariff as currently proposed would constitute a violation of G.S. 15A-261(a), North Carolina's version of the "Trap and Trace Statute" and that, moreover, even universal free blocking would not remedy this defect absent changes in the federal and state law.

The Attorney General explained that North Carolina's "Trap and Trace Statute" (G.S. 15A-260 et seq.) was enacted pursuant to the requirements of the federal Electronic Communications Privacy Act (ECPA) of 1986, and tracks that statute nearly word for word. (Other states have also enacted "state ECPAs" pursuant to this mandate with virtually identical wording).

Both the North Carolina and federal statutes define a trap and trace device as follows:

> A device which captures the incoming electronic or other impulses which identify the originating number of an instrument or device from which a wire or electronic communication was transmitted. (G.S. 15A-260(3); 18 USC § 3127(4)

G.S. § 15A-261 reads as follows:

> § 15A-261. Prohibition and exceptions.
> (a) In General - Except as provided in subsection (b) of this section, no person may install or use a pen register or a trap and trace device without first obtaining a court order as provided in this Article.
> (b) Exception - The prohibition of subsection (a) of this section does not apply to the use of a pen register or a trap and trace device by a provider of wire or electronic communication service:
>
> > (1) Relating to the operation, maintenance, or testing of a wire or electronic communication service or to the protection of the rights or property of the provider, or to the protection of users of that service from abuse of service or unlawful use of service; or
> > (2) To record the fact that a wire or electronic communication was initiated or completed in order to protect the provider, another provider furnishing service toward the completion of the wire communication, or a user of that service, from fraudulent, unlawful or abusive use of service; or
> > (3) With the consent of the user of that service.

(c) Penalty. - A person who willfully and knowingly violates subsection (a) of this section is guilty of a misdemeanor punishable by a fine, imprisonment of not more than only one year, or both (1987) Reg. Sess., 1988), c. 1104, s. 1.)

The Caller ID device which the subscriber must buy to receive the Caller ID service is, the Attorney General contended, just such a trap and trace device. The Attorney General further argued that Caller ID does not fit any of the statutory exceptions listed in G.S. 15A-261(b) for use of a trap and trace device, because all the exceptions listed are limited to use of such a device by the telecommunications provider.

By contrast, on August 3, 1990, Southern Bell denied that Caller ID display device is a "trap and trace device" at all. Southern Bell argued that the Caller ID display unit performs no "capture" function; rather, the technology needed to provide Caller ID software and hardware is located in the phone company's central office. The display unit is a passive mechanism which merely displays information forwarded by Southern Bell after the phone company has generated transmission, and recorded the information within the network.

The Attorney General replied on January 3, 1991, that a trap and trace has occurred when the number is successfully transmitted from the switch to the display device. The Attorney General contended that Southern Bell's assertion regarding the role of central office hardware and software was irrelevant--a display of some sort is an integral part of the equipment which captures the electronic impulses.

The Attorney General also noted that two courts have construed Caller ID and have reached opposite conclusions. In Pennsylvania, the service was declared illegal and unconstitutional by the Commonwealth Court on May 30, 1990. Barasch v. Pennsylvania Public Utility Commission, 76 A. 2d 79 (Pa. 1989; on appeal to Pennsylvania Supreme Court) (hereinafter Barasch). In South Carolina, a lower trial court found that the service did not violate South Carolina's corollary to NCGS 15A-260 et seq. Southern Bell v. Hamm, Case No. 90-CT-40-26865; appeal to South Carolina Supreme Court filed December 20, 1990) (hereinafter Hamm). The South Carolina Trial Court found that the service fell within the statutory exceptions set out in § 17-29-20 (identical to G.S. 15A-261).

Most of the legal focus of this docket has been on the construction of the trap and trace statute. Parties have on occasion raised other issues dealing, for instance, with asserted constitutional rights to privacy, an important issue in Barash, supra., and explicitly rejected in Hamm, supra., but no sustained or convincing argument relating to alleged unconstitutionality has been made in this docket. The Attorney General opined on July 19, 1990, that this issue was "not central to the Commission' deliberation at this point" and was not to be interpreted as assent to Southern Bell's argument in its supplemental filing of June 6, 1990.

1. Public policy issues. Aside from the legal issues, the public policy issues loom largest in the Caller ID debate. These issues include the alleged usefulness of the service, privacy concerns, and questions as to the appropriate extent of blocking. Not surprisingly, the parties hold widely divergent views on these questions.

Southern Bell maintains that Caller ID is a useful deterrent to harassing and threatening phone calls as well as a convenience to the called party who simply wishes to screen his calls. With respect to the privacy interest, Southern Bell maintained that the privacy interest of the called party is primarily "the right to be left alone by all except those with whom the called party desires contact." The asserted right to privacy of the calling party is not a legitimate privacy interest at all, Southern Bell argued, but an assertion of a right to anonymity. Southern Bell likened Caller ID to an electronic "peephole" through which the called party can identify callers. Southern Bell has proposed per-line blocking for certain categories of public agencies but maintains that universal per-line blocking would destroy the value of the service.

The Attorney General and the Public Staff, on the other hand, were skeptical of the alleged benefits of Caller ID in such areas as reducing harassing and threatening phone calls. They argued that the same benefits could be and in fact were derived in a less intrusive manner from such TouchStar options as Call Block, Call Tracing, and Call Return. As to privacy interest, those parties maintained that Southern Bell's notions of legitimate privacy interests were too narrow, as were Southern Bell's proposals regarding blocking. Southern Bell has provided no detailed plan setting out how its proposed blocking options would be administered, including such issues as public notice of the blocking option, administration of the "certification program," right to appeal, and renewal requirements.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

1. Caller ID is not illegal.

After careful consideration of the filings in this docket, the Commission believes that the Caller ID hardware/software constitutes a "trap and trace device" within the meaning of G.S. 15A-260(3), but that its use falls within the exceptions outlined in G.S. 15A-260(b)(1), (2), and (3).

The parties have tended to debate this question in terms of whether or not the display unit is a device within the meaning of the statute. The Attorney General has argued that it is such a device; Southern Bell has denied this argument and argued that all meaningful activity occurs within the central office.

The Commission believes that concentrating on the display unit by itself is misplaced. Websters New International Dictionary defines a "device" as "something that is formed or formulated by design, usually with consideration of possible alternative, experiment, and testing." A similar definition, "that which is devised or formed by design. . . tangible means instrument, contrivance," can be found in 12 Words and Phrases, "Device." The Commission believes that the word "device" extends beyond the mere electronic display unit and encompasses the display unit and all other hardware and software necessary for the display unit to perform its function.

Therefore, Caller ID hardware/software plainly constitutes a "device which captures the incoming electronic . . . impulses which identify the originating number of an instrument or device from which a wire or electronic communication was transmitted." G.S. 15A-260(3).

G.S. 15A-261 provides that "no person may install or use. . . a trap and trace device without first obtaining a court order. . ." The purpose of the statute was apparently to prohibit the use of such devices by anyone, except with a court order or as provided in a list of exceptions.

Those exceptions are listed in G.S. 15A-261(b)(1), (2), and (3). G.S. 15A-261(b) states that the above prohibition does not apply to the <u>use</u> of a trap and trace device by a <u>provider</u> of wire or electronic communication service in the following relevant circumstances:

(1) "Relating to . . . the protection of users of that service from abuse of service or unlawful use of service" (G.S. 15A-261(b)(1)).

(2) "To record the fact that a wire or electronic communication was indicated or completed in order to protect. . . the user of that service from fraudulent, unlawful, or abusive use of service." (G.S. 15A-261(b)(2)).

(3) "With the consent of the user of that service." (G.S. 15A-261(b)(3).

The Commission believes that the better analysis is as follows: The Caller ID service essentially constitutes a "use of a trap and trace device by the provider," i.e., the telephone company. The hardware/software of the phone company captures the number and transmits it to an otherwise inert box under the subscriber's ownership and control. One of the major purposes of the Caller ID service is to protect the user--i.e., subscriber--from abuse of service or unlawful use of the service or to protect the user from fraudulent, unlawful or abusive use of the service. Moreover, the subscriber's voluntary sign-up for Caller ID may be said to constitute his consent, and the use of the singular indicates dual-party consent is neither implicitly or explicitly required. Thus, Caller ID falls within all three exceptions in G.S. 15A-261.

The Commission recognizes that there is considerable dispute over the construction of this statute with respect to Caller ID and that reasonable persons can disagree. Perhaps a major reason for this division is that the statute was not drafted with Caller ID in mind since Caller ID did not yet exist as a service offering. However, almost all states that have considered Caller ID and the issue of legality have not considered the statute a legal impediment. In any event, the Commission believes that the better view is one finding Caller ID not to be illegal. The next question involves the public policy issue concerning under what conditions Caller ID should be offered.

2. <u>Caller ID is in the public interest subject to per line and per call blocking.</u>

If the determination of the legality of Caller ID is a complex matter, the determination of the public interest standard for Caller ID is no less so.

An appropriate analysis of Caller ID must consider the service within its proper context. Although the term Caller ID is sometimes used to refer to all calling number display generally, Caller ID is in fact only one example of a calling number identification and display service. Calling number identification and display is also available through certain other services such as Automatic Number Identification (ANI). One important example of calling number identification and display available through ANI is E911 service. The calling number display for most of the services can be blocked but, at the current time, ANI calling number display cannot be.

The availability of calling number identification and display technologies continues to grow. This growth, especially with respect to Caller ID, has led to increasing concern over privacy.[1] Caller ID puts privacy concerns in bolder relief because it is what may be called an external use of calling number display--that is, persons on a phone system external to the caller's, who may have no preexisting relationship to the caller, have access to the caller's phone number.

Hitherto, calling number display has been mainly restricted to internal uses. The obvious and necessary example of such internal use is the telephone company's use of number identification and display for billing or network maintenance and security purposes. The Commission has also allowed a limited number of special tariffs with calling number identification and display for employer-specific phone systems--that is, numbers internal to that phone system can be displayed, but not numbers from the public-at-large external to that phone system.

One example of the approval of external use calling number identification and display with little controversy is E911. G.S. 62A-3(1) keys the definition of E911 to the capabilities for automatic number identification and automatic location identification features. However, G.S. 62A-9(a) forbids the local government to release the number other than for emergency purposes to appropriate personnel. In the case of E911, there is a strong public policy expressed by statute in favor of emergency service. It is also hard to conceive that a person in distress would not wish his number to be disclosed for emergency purposes. Lastly, disclosure of the person's number for other purposes is strictly forbidden.

If the privacy interest is attenuated in the case of E911, the same cannot be said in the case of Caller ID. In unrestricted Caller ID there is an external use in which the party receiving the number is under no obligation to keep the number he has received confidential. There are many circumstances where a

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[1]For example, the New York Public Service Commission in Case 90-C-0075, issued on March 22, 1991, articulated an eight-point statement of policy regarding privacy interests. The policy statement said, among other points, that privacy should be explicitly recognized as an issue to be considered in introducing new services and that people should be permitted to choose among various degrees of privacy protection both with respect to the outflow of information and the receipt of intrusions.

calling party may not wish to disclose his number. The mere existence of Caller ID will tend to change traditional expectations regarding calling number disclosure in telecommunications.

One of the aspects to the Caller ID controversy which makes it so complex is that arguably privacy interests exist on both sides--for the called party as well as the calling party. For example, the called party may arguably have a privacy interest in "being let alone," while the calling party may have a privacy interest in not disclosing information about himself. Caller ID with blocking may tend to diminish the absolute maximum value of the service to the called party, but Caller ID with no blocking may inflict social harm on certain groups (e.g., women's shelters) and negate the value of service to others (e.g., subscribers who have paid for a private number). The Commission believes the restriction of legitimate privacy interests simply to the "right to be let alone" is too narrow.

Like many other public policy questions, Caller ID must be analyzed in terms of the balancing of equities and interests. Certainly, there are advantages from Caller ID but there are also disadvantages to be considered which weigh against unrestricted Caller ID.

Fortunately, the equities concerning Caller ID can be balanced in a general sense according to the degree of blocking that is available. The Commission believes that the opponents to untrammelled Caller ID have presented a cogent case for blocking, arguments which Southern Bell has explicitly accepted in part when it scaled back its proposal from Caller ID without blocking to Caller ID with blocking for selected groups.

Aside from E911 noted above, Caller ID constitutes the first major external use of one of the calling number identification and display technologies. As with all such external uses, the Commission must balance the usefulness and advantages of the service as against privacy interests and expectations and the disadvantages that may flow from the service.

The Commission believes that the balance can best be struck by allowing Caller ID as an experiment for a two-year period subject to the provision of universally available per-line (by subscriber request) and per-call blocking.

The Commission believes that the availability of per-line and per-call blocking is important in protecting legitimate and deeply felt privacy interests and expectations. It is in accord with what the Attorney General has called the optimal configuration. Furthermore, the experimental nature of the offering will allow the collection of valuable data about the service.

In addition, universal per-line blocking will obviate the necessity for the telephone company to set up an administrative procedure to determine who would or would not qualify for per-line blocking, as would be required under Southern Bell's amended proposal. Moreover, the person who desires not to disclose his number at all can effect this choice without having to input several extra digits before each telephone call. The approach of per-line and per-call blocking has been adopted or indicated by several states and reflects a trend toward more expansive blocking policies.

The Commission is also concerned that subscribers receive adequate notice concerning Caller ID, especially since the Commission is allowing Southern Bell to require an affirmative act by a subscriber to obtain per-line blocking.

The following are the major terms and conditions under which Caller ID may be offered:

1. Caller ID is to be offered only with the provision of free and universally available per-line and per-call blocking. The telephone company may require that a subscriber contact the company in order to obtain per-line blocking.

2. The telephone company must send a notice, approved by the Commission, every six months to each affected subscriber describing Caller ID and how the subscriber may obtain or utilize both forms of blocking. A subscriber must be advised that he can obtain per-line blocking at any time by oral or written communication to the company.

3. The telephone company must send a written ballot, approved by the Commission, at least once a year advising each affected subscriber that he may choose per-line blocking by returning the ballot as appropriately marked to the company. The subscriber is to be able to send the ballot back to the company with his bill.

4. The telephone company must advise each new affected subscriber when he is signing up for service that per-line blocking is available to him without charge and how he can utilize per-call blocking.

IT IS, THEREFORE, ORDERED as follows:

1. That Caller ID be allowed on an experimental basis for two years subject to free and universally available per-line and per-call blocking.

2. That if Southern Bell desires to offer the service, it refile its tariff in accordance with the provisions of this Order. Such tariff shall become effective upon further Commission Order.

3. That Southern Bell provide notice to affected subscribers and opportunity to select per-line blocking as set out above. Such notice and ballot shall be subject to Public Staff review and Commission review and approval. Public notice and ballot are necessary before the Caller ID service may be offered.

4. That Southern Bell provide the following data regarding the Caller ID service at least two months before the end of the two-year experimental period:

a. Number of subscribers to Caller ID

b. Number of subscribers choosing per-line blocking
c. Number of subscribers with non-published numbers and non-listed numbers.
d. Number of subscribers with non-published and non-listed numbers requesting blocking.

e. Number of subscribers with per-line blocking who subsequently cancel that blocking.

5. That Southern Bell and law enforcement agencies coordinate, if necessary, to accommodate necessary and appropriate law enforcement concerns arising from the provision of Caller ID as set out herein.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of May 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

Commissioner Sarah Lindsay Tate concurs.
Commissioner Ruth E. Cook joins.
Commissioner Charles H. Hughes dissents.

DOCKET NO. P-55, SUB 925

COMMISSIONER SARAH LINDSAY TATE CONCURRING: I reluctantly concur with the Order issued today because it allows telephone subscribers the absolute right to block the use of this nefarious device free of charge. Southern Bell describes Caller ID as a "peephole" to protect the called party. I view Caller ID as a "peeping Tom" to invade the privacy of the calling party. To me, it is unrealistic to assume residential customers are able to recall the numbers of all acceptable callers. I believe Caller ID's primary use is intended for businesses to compile numbers for solicitation purposes. Southern Bell expressed no concerns for the 409,900 subscribers who presently have unlisted or non-published numbers. Without per-line blocking, this long-established right to privacy would be summarily and permanently denied.

I also concur because Caller ID is allowed only as an experiment. The Commission can reevaluate its worth when it has actual data on its usage and its users. Technological advances offer vast opportunities, but we must be very careful to ensure that valuable rights are not lost in the process.

Sarah Lindsay Tate, Commissioner

Commissioner Ruth E. Cook joins.

Commissioner Charles H. Hughes, dissenting:
I dissent from the Majority's decision on both legal and public policy grounds.

First, I do not believe that Caller ID is legal under the provisions of G.S. 15A-260 et seq. The Pen Register and Trap and Trace Device statute, which tracks virtually word-for-word the provisions of the federal Electronic Communications Privacy Act (ECPA) of 1986. I do not believe that Southern Bell has carried its burden of proof to demonstrate the legality of the service.

The Majority agrees that Caller ID is a "trap and trace" device under G.S. 15A-260(3). The Majority also agrees that the purpose of the statute, as expressed in G.S. 15A-261, was to prohibit the use of such devices by anyone except with a court order or as provided in the list of exceptions.

Where the Majority and I part company is whether Caller ID falls under any of the three exceptions listed in G.S. 15A-261(b). I believe that the case for the proposition that Caller ID does not fall under any of the three exceptions is compelling.

G.S. 15A-261(b) sets out three exceptions to the court order requirement. The beginning clause states in relevant part:

> . . . [T]his section does not apply to the use of a . . trap and trace device by a provider of a wire or electronic communication service. (Emphasis added)

By its terms, therefore, the exceptions are limited to use of the trap and trace device by the provider, not the subscriber.[1]

The central question pursuant to this clause is: Who is using the trap and trace device in the Caller ID context? The Commission believes that the subscriber is the real user of the trap and trace device. After all, he is paying for the service; the calling number is being captured and displayed on his device at his home or business for his benefit. This is not an insubstantial, indirect, or attenuated use. Even if it can be said that the telephone company--the provider--is using the device, the fact remains that the subscriber is using the device as well, and the exceptions do not apply to the subscriber. Thus, since Caller ID is predicated on such use by the subscriber, questions as to the legality of the service remain.

In any event, even if the service were construed solely as a use of the trap and trace device by the provider, which it is not, the exceptions would not apply. The exceptions under G.S. 15A-261(b)(1) and (b)(2) contemplate the telephone company's protecting the integrity of its system and its customers from specific acts of fraud or abuse. It should be remembered that ECPA on which the State Trap and Trace statute was based was passed before Caller ID came into existence as a service offering. It would be a strained reading indeed to say that these statutory exceptions were intended to allow the constant, indiscriminate collection of calling numbers. Moreover, although Caller ID is touted as a means of combatting fraud and abuse, it is also promoted simply as a convenience--a screening device. This type of use is not mentioned among the exceptions.

The third exception is the consent provision under G.S. 15A-261(b)(3). Here there is the question of who is the user in this context. The user is not solely the subscriber to Caller ID but may also be the calling party--who himself may

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[1]As an additional point in favor of this construction, it should be noted that where the Legislature or Congress intended an exception to apply to both the providers and their customers, it stated that intention clearly. See e.g., 18 USC 3127(3) or 15A-260(2), which includes both the provider and customer use within the billing exception to the restrictions of the use of pen registers: ". . . but the term [pen register] does not include any device used by a provider or customer of a wire or electronic service for billing. " (Emphasis added).

be a customer of the same phone company. The better reading is that G.S. 15A-261(b)(3) was intended to allow the subscriber to consent to the phone company placing a trap and trace device on his phone line for the purpose of a police investigation or detecting specific acts of fraud and abuse.

Even if Caller ID were legal--and I do not think that it is under the current statute--I still do not believe that it is in the public interest. Somehow the notion has gotten about that simply because a technology is new and available that this in itself constitutes sufficient basis to allow--even to compel--its use. I think this is nonsense. I believe that we must examine these technologies--especially these privacy-compromising technologies--very carefully. To my mind Caller ID comes up short.

First of all, I believe that its benefits have been vastly oversold. The telephone companies have presented it with minimal quantitative support as a remedy for harassing and threatening phone calls, when in fact the main impetus behind it is its commercial uses--specifically, the accumulation, collation, and distribution of every more comprehensive databases. This may lead ironically to more unwanted phone calls to the individual, not fewer.

A less intrusive alternative to solving the problem of harassing or threatening phone calls was presented by the Attorney General. It was to modify Southern Bell's Call Trace tariff to put that tariff on a non-presubscribed, per-call basis. With Call Trace, the appropriate authorities receive the offending phone number, not the subscriber directly. This will tend to reduce the problem of counter-harassment or even "private justice," which has been reported in some Caller ID states. Unfortunately, Southern Bell has resisted this tariff modification, although at least one local exchange company has filed such a tariff and another has one pending.

Even as the benefits have been oversold, the negative aspects have been frequently underrated. The fact is that Caller ID will tend to change expectations concerning privacy that have been in place for decades. An obvious disadvantage of Caller ID is that it will tend to diminish the value of private numbers. But there are other disadvantages as well--the accumulation of commercial databases, as mentioned above; the facilitation of redlining; unwanted disclosure of locations, especially of certain professionals and public persons; and reverse harassment, to name just a few. Even with blocking, it may lead to discrimination against those with blocking.

The privacy questions related to Caller ID are real. I am glad to see that some states, such as New York, are developing overall privacy principles which was alluded to in the majority's decision. I believe that principles like these should inform this Commission's decision-making. Those principles are:

1. Privacy should be recognized explicitly as an issue to be considered in introducing new telecommunications services.

2. The interest in the open network should be recognized in evaluating alternative means for protecting privacy.

3. Companies should educate their customers as to the implications for privacy of the services they offer.

4. People should be permitted to choose among various degrees of privacy protection with respect to both the outflow of information about themselves and the receipt of incoming intrusions.

5. A telephone company offering a new service that compromised current privacy expectations would be obligated to offer a means of restoring the lost degree of privacy, unless it showed good cause for not doing so.

6. Considerations of cost, public policy, economics, and technology all bear on the pricing of privacy features, which must be determined case-by-case.

7. Unless a subscriber grants informed consent, subscriber-specific information generated by the subscriber's use of a telecommunications service should be used only in connection with rendering or billing for that service or for other goods or services requested by the subscriber.

8. Privacy expectations may change over time, requiring, in some instances, changes in telecommunications services. At the same time, changes in telecommunications technology services and markets may lead to changes in customer's privacy expectations.

While these principles were not explicitly utilized in the majority's decision, I am pleased that the majority recognized the existence of a privacy interest and was willing to go so far as to adopt the policy of per-line as well as per-call blocking.

Still, I must respectfully dissent from the Majority's view. In my opinion, Caller ID is neither legal, nor in the public interest for the reasons stated above.

Charles H. Hughes, Commissioner

DOCKET NO. P-55, SUB 942

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Tariff Filing by North State Telephone Company and) ORDER ALLOWING
Southern Bell Telephone and Telegraph Company for) TRIAD CALLING
Implementing the Triad Calling Plan) PLAN

BY THE COMMISSION: On October 17 and 23, 1990, Southern Bell and North State Telephone Companies, respectively, filed tariffs proposing to establish an 18-month trial of a Triad Regional Calling Plan (TRCP). The TRCP includes options for expanding local calling in the Triad area among Southern Bell's Greensboro, Julian, Monticello, Summerfield, and Winston-Salem exchanges and North State's High Point exchange. Neither company specified an effective date for the tariffs but each requested timely approval of the TRCP since it will take approximately 15 months to implement the proposed service from the date of Commission approval. The TRCP was agreed upon by both companies and representatives of subscribers and various government groups in the specified exchanges to address the growing calling needs of the area which was recently addressed by an EAS proposal in Docket No. P-55, Sub 898. In that docket, the Commission declined to continue a proposal for two-way, non-optional EAS among 15 exchanges serving the Triad region in Guilford and Forsyth Counties. The TRCP has been endorsed by the Triad Telephone Committee (TTC) which promoted the recent EAS proposal.[1]

The TRCP is the same as the Pender County Calling Plan recently approved by the Commission and contains the following five service characteristics:

1. Seven-digit dial calling between North State's High Point exchange and Southern Bell's exchanges in the Triad area;

2. Provision of a combined telephone directory (white pages) which includes North State's High Point exchange telephone numbers and all of the Triad area Southern Bell telephone numbers;

3. The introduction of the Community Caller Plus option which provides a 50% reduction in charges for calls between the exchanges in the Triad area as defined above which are currently classified as toll calls;

4. The introduction of an inward calling option. This optional service would allow the called party to pay the charges in lieu of the calling party;

5. The introduction of the Thrifty Caller low-use calling option. This option will be designed to benefit customers who do not make many calls within their home exchange. Under this plan, the basic monthly rate for telephone service will be significantly reduced and all calls within the service area would be assessed a charge based on a local usage schedule.

This matter came before the Regular Commission Conference on November 19, 1990. The Public Staff recommended that the Commission approve the trial TRCP as proposed in the tariff filings by Southern Bell and North State. The following persons appeared to speak in favor of the proposal or in favor of their community's inclusion in the proposal: John Ray, Chairman of TTC; Vic Nussbaum, Mayor of Greensboro; Representative Trip Sizemore of Guilford County; Wayne Corpening, former Mayor of Winston-Salem; Gray Swain, Mayor of Walkertown; Senator Mary Seymour of Guilford County; Don Dixon of American Express in Greensoboro; Lloyd Walter, an architect in Winston-Salem; Roger Swisher, Mayor of Kernersville; Barbara Bull of Kernersville; Tom Penland, Prinicpal of Eastern Guilford High School in Gibsonville; and Mike Hedron of Greensboro.

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[1]On April 1, 1991, Central Telephone Company filed tariffs that would offer a similar discount rate package to its Walkertown exchange with terminating exchanges in High Point, Greensboro, Julian, Monticello, and Summerfield.

The following representatives of the telephone companies appeared: Bill Dula of North State and Al Povall of Southern Bell, who favored the proposal; Dwight Allen of Carolina Telephone and Kent Burns representing ALLTEL, who opposed it; and Katie Cummings of AT&T, who was concerned with access charge issues. Karen Long of the Attorney General's Office also voiced concerns about the proposal.

During the Commission Conference, the representatives for Southern Bell and Carolina engaged in a spirited oral argument. These arguments were foreshadowed, reiterated, or expanded in a series of filings by parties: By North State on November 26, 1990; by Southern Bell on December 10, 1990; by Carolina on November 14, 1990, and January 14, 1991 and March 20, 1991; and by Southern Bell on February 28, 1991.

A concise summary of the main arguments of the parties is below:

Carolina. Carolina, whose Kernersville and Gibsonville exchanges are not part of the proposal, argued that the TRCP is inappropriate because there is, in many instances, no demonstrated community of interest among many of the exchanges. Carolina also warned that there would be a serious settlement impact of the proposal on the pool and had disputed the reliability of the figures offered by Southern Bell. Carolina requested that Southern Bell be required to furnish more comprehensive and representative data on pooling impacts. Additionally, Carolina raised discrimination concerns, whether or not the calling is classified as local or long-distance, since one select group may be receiving a benefit not available to others similarly situated. Furthermore, if the service offering is classified as local rather than as long-distance as Carolina maintains, then the offering would amount to mandatory local measured service at rates substantially higher than the optional local measured service in effect experimentally. If it is toll, then the Commission has compromised its policy of uniform toll rates. Carolina argued in favor of a full and complete evidentiary hearing on the proposal.

Southern Bell. Southern Bell emphatically argued that the TRCP is a local plan rather than a toll plan. Southern Bell maintained that this classification as local would obviate discrimination concerns. Southern Bell also argued that the effect on the pool of the TRCP for the cost companies would be minimal--approximately $2,228, 130 against 1989 pool revenue of nearly $315 million. Between January 1989 and July 1990, Southern Bell stated the settlement ratio has fluctuated between a low of 18.71% to a high of 32.59%, an average fluctuation of 3.97% per month. The total impact of the Triad Plan would be 0.88%. Moreover, Southern Bell noted, all EAS proposals have some degree of impact on the pool. As for mandatory local measured service, Southern Bell denied that the plan was mandatory since the customer has the choice to make the call, in contrast to flat rate EAS, where there is no choice as to the payment of the EAS additive. As to community of interest, Southern Bell maintained that Forsyth and Guilford Counties possess a strong sense of regional identity, with numerous shared facilities and institutions, such as the Triad Regional Airport, a Triad Chamber of Commerce, and numerous civic, corporate, and governmental entities. In any event, the Commission can set appropriate criteria. Southern Bell argued the overall superiority of the TRCP as providing expanded options to Triad subscribers that would be universally available with no buy-in or extra monthly charge.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The Commission has for some time acknowledged that regional calling proposals present unique challenges. In the predecessor to this docket (Docket No. P-55, Sub 898), the Commission found that by and large the appropriate EAS additives were too high and the general community of interest too low to justify continuation of the flat rate EAS process for the Triad.

Now, however, the parties have returned together and made a proposal as set out above which is endorsed by the Public Staff. This proposal has several attractive features, not least of which are seven-digit dialing and a combined white pages directory. The proposal would be universally available, requires no buy-in, and offers subscribers a substantial reduction in toll rates while the telephone company has the opportunity to recoup lost revenues through stimulation. Those who have appeared before and written the Commission have demonstrated a community of interest sufficient to justify proceeding with the proposal on an experimental basis.

Nevertheless, certain issues remain to be resolved. One of the issues--geographical extent--is an issue that can be resolved in this Order. The other issues--issues such as pooling and the classification of revenues and the implications thereof raised either explicitly or implicitly by Carolina--are either factual or legal and public policy issues and must await resolution within the context of a separate docket. However, since these latter issues are not central to whether there should be a discount, but rather to how the revenues should be classified, the Commission does not believe that their pendency should in any way prevent the Companies from moving ahead with the implementation of the calling plans. The Commission is committed on an experimental basis to the implementation of a discount-rate plan as soon as practicable and only certain questions await resolution. Fortunately, the 12

to 15 months time-frame projected for implementation allows the Commission the opportunity to examine and resolve these questions before the service begins.

The following are the major issues to be addressed:

1. Geographical extent. The tariffs that Southern Bell and North State have filed would offer reduced rate calling between and among all the Southern Bell exchanges in the Triad (Greensboro, Julian, Monticello, Summerfield, and Winston-Salem) and North State's High Point exchange. Similarly, High Point would enjoy reduced rate calling to all the named Southern Bell exchanges. Central Telephone Company has also made a proposal for its Walkertown exchange as noted above, which the Commission believes should also be a terminating exchange.

Carolina has not proposed that its Kernersville and Gibsonville exchanges be included in the calling plan. Some citizens and officials in these communities have expressed interest in being included in the proposal.

At this point in time, since Carolina has not proposed that its exchanges be included or submitted tariffs to include them and has questioned the TRCP as currently constituted so vigorously, the Commission believes that the experimental area should be that proposed by Southern Bell, North State, and Central Telephone Company. However, since this plan is an experiment, it will not preclude inclusion of these exchanges at some later date.

2. Pooling issue. This is a factual issue raised by Carolina. Essentially, Southern Bell has proposed a 50% reduction in charges for calls within the Triad region. The revenues from such calls are currently classified as "intraLATA toll" and pooled in the North Carolina intraLATA toll pool. Southern Bell has proposed to classify those revenues from the discount as local. Carolina has argued that the pool impact may be significant, while Southern Bell has argued that it would not be.

3. Classification of revenues as local or long-distance. This issue has both legal and public policy implications. The appropriate classification of discount interexchange revenues within the plan was a major point of contention between Southern Bell and Carolina. Southern Bell adamantly maintained that such revenues should be classified as local, while Carolina was just as adamant that the proper classification was long-distance.

a. Classification as local. It has been suggested that if the revenues are classified as local, then the Commission will arguably have adopted a form of compulsory local measured service. Such service would arguably be compulsory because this plan would become the only way the subscriber could make this type of local call. The Commission has never approved compulsory local measured service or even optional local measured service as a regular service offering.[2] (See Docket Nos. P-55, Sub 806, and P-7, Sub 679). Moreover, classification as local might arguably also raise discrimination problems. The local service here is different from local service derived from EAS because here there is no EAS additive that all subscribers are paying. There is, therefore, arguably discrimination between subscribers with local service in other parts of the State who are paying an EAS additive and those here who are not.

b. Classification as long-distance. While classification as long distance would negate the issue of compulsory local measured service and would quell pool concerns, such a classification may be vulnerable to charges of discrimination, since subscribers in the Triad would be receiving the benefit of reduced long-distance rates not available to subscribers in areas outside the Triad.

The Commission believes that discrimination concerns as between plan recipients and others can be addressed by framing reasonable criteria by which a regional community may apply for and receive a plan involving discount rates. An ultimate solution to discrimination concerns would also involve the

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[2]It should also be noted that Southern Bell and North State are proposing a so-called Thrifty Caller option, which is a true optional measured service offering since the subscriber must make an affirmative choice for the service before he can receive it and he can, of course, elect not to take it at all. The Commission believes that optional local measured service within the context of this alternative plan, rather than as a regular service offering, is not objectionable.

determination of a uniform rate of discount to ensure non-discrimination as between plans.

As stated above, the Commission believes that the best approach is to move forward toward implementation of the discount proposal and, in the meantime, hold a generic investigation of the factual, legal, and public policy questions raised by the pooling and associated issues. This generic investigation will tentatively consist of two major parts:

1. Implications of classification of discount revenues as either local or long-distance.
   a. Pooling impact, if classified as local
   b. Compulsory local measured service issue if classified as local
   c. Discrimination issue, if classified as local
   d. Discrimination issue, if classified as long-distance

2. Appropriate standards for instituting discount regional calling plans.

The Companies accordingly will be on notice that the results of the generic proceeding will determine how discount revenues are classified and, to this extent, their tariffs may need modification after the Commission Order in that docket.

Finally, since the TRCP is experimental, the Commission will be requiring the Companies to submit data concerning how the plan is working. The exact nature of these data requirements will be the subject of a subsequent Order.

IT IS, THEREFORE, ORDERED as follows:

1. That Southern Bell's, North State's, and Central Telephone Company's proposed tariffs, as amended pursuant to Ordering Paragraph No. 3, be allowed to go into effect on an experimental basis at the same time and at such time as the Companies are technically capable of offering the service subject to Commission order. The Companies shall inform the Commission at such time as they have a date certain for implementation.

2. That the experimental period be 18 months from the effective date of the tariffs.

3. That Southern Bell and North State amend their proposed tariffs to include Walkertown as a terminating exchange.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of April 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

DOCKET NO. W-798, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of John C. Newton, Bald Head Island, Southport, North Carolina 28461, Complainant v. Bald Head Island Utilities Inc., Respondent	)	ORDER GRANTING COMPLAINT AND REQUIRING REFUNDS

HEARD IN: Bald Head Island Village Chapel, North Bald Head Wynd, Bald Head Island, North Carolina, on Thursday, March 14, 1991, at 10:15 p.m.

BEFORE: Commissioner Charles H. Hughes, Presiding; Chairman William W. Redman; and Commissioner Laurence A. Cobb

APPEARANCES:

For Bald Head Island Utilities, Inc:

Robert F. Page, Attorney at Law, Crisp, Davis, Schwentker, Page & Currin, Post Office Drawer 30489, Raleigh, North Carolina 27622

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: By letter dated February 25, 1991, John C. Newton ("Complainant") filed a complaint in this docket against Bald Head Island Utilities, Inc. ("BHIU"). The Complainant requested that the Commission declare that the septic system on his property is not subject to the control of BHIU.

The Complainant alleged in his letter that he built a permanent residence in 1982 and had his own sewage and water system installed according to specifications. He stated that at no time had he ever been on, or desired to be on, the BHIU system. He attached exhibits to his letter showing that BHIU regarded him as a utility customer and had even gone on his property and disabled the septic tank because he refused to pay for sewer service from BHIU.

On March 11, 1991, the Commission issued an Order scheduling the matter for hearing on Thursday night, March 14, 1991, at the Bald Head Island Village Chapel on Bald Head Island.

The hearing was held as scheduled on Thursday night, March 14, 1991. The Complainant, John C. Newton, and his wife, Alice Newton, testified in support of the complaint. The Respondent, BHIU, presented David Edwards, Manager of BHIU, and Michael Kent Mitchell, President of BHIU.

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

FINDINGS OF FACT

1. BHIU was formed and incorporated in 1981 by Bald Head Island Corporation, the original developer of Bald Head Island. BHIU was transferred to Bald Head Island Limited, the current developer, on June 14, 1983. BHIU applied for a water and sewer utility franchise on June 18, 1984, was granted Temporary Operating Authority on July 24, 1984, and was granted a Certificate of Public Convenience and Necessity to provide water and sewer utility to Bald Head Island On April 11, 1985.

2. There are four types of sewer systems serving customers on Bald Head Island: (1) conventional septic tank type systems serving individual houses; (2) low pressure septic tank type systems serving individual houses; (3) low pressure septic tank type systems serving multiple houses; and (4) gravity type collection systems with central treatment plants.

3. The Complainant, Mr. Newton, purchased Lot No. 807 and had his house constructed and his well and septic tank system installed in 1982. His house is served by an individual low pressure type septic tank system he had installed on his property. The electrical circuitry for the system is connected to the electric service of his house.

4. The Complainant paid approximately $3,000.00 to have the low pressure septic tank type system installed.

5. BHIU applied to the Division of Environmental Management (DEM) on May 13, 1982, for blanket approval to construct low pressure septic systems on Bald Head Island. DEM approved the request under Permit No. 7964 on March 4, 1983. Lot No. 807, the Complainant's lot, was not listed on that permit.

6. BHIU applied to DEM for approval of the low pressure sewer system for Lot No. 807 on January 28, 1983. DEM approved the system on May 8, 1984, under Permit No. 7964R.

7. There were existing homes being served by individual septic tank systems when BHIU was granted blanket approval under Permit No. 7964 for the design and operation of low pressure type sewer system to be constructed on Bald Head Island. In 1983, BHIU approached each of the approximately 20 existing homeowners who had individual septic system and offered to maintain their systems for $20.00 per month. Approximately one half of those homeowners signed contracts to pay BHIU to maintain their systems. The Complainant did not sign a contract but did start paying the $20.00 per month. BHIU started billing these homeowners in 1986.

8. The Complainant purchased his lot from United Carolina Bank which had acquired the property through foreclosure from the previous developer. He was not required to sign a HUD Property Report when buying this property and was not

made aware of any provisions, if they existed, in such report concerning utility service.

9. BHIU notified the Complainant by letters dated October 4, 1988, and November 3, 1988, that his account was past due with a balance due of $126.63. As of November 22, 1988, the Complainant still had not paid this balance, and BHIU disconnected the Complainant's sewer system for non-payment. The Complainant made payments in April 1989, which resulted in a credit balance to his account of $13.37. On May 10, 1989, BHIU notified the Complainant in writing that the reconnect fee was $15.00 and that his service would be reconnected upon payment of $1.63. The Complainant paid the $1.63 balance in August 1989, at which time his service was reconnected.

10. In order to disconnect the Complainant's sewer service in November 1988, BHIU had its personnel remove the circuit breaker from the electric panel located under the steps of the Complainant's house. BHIU did not notify Complainant that his service had been disconnected. On at least two occasions during the period of disconnection, BHIU's personnel temporarily reinstalled the Complainant's circuit breaker for the purpose of pumping down his septic holding tank without the Complainant's knowledge.

11. The Complainant became aware of BHIU's disconnection of his sewer system when he and his wife detected sewage odor at their house. Because the pump in the septic tank had been disabled by removal of the circuit breaker, the sewage in the septic tank had risen above its proper level and damaged the electrical wiring in the septic tank. As a result of the damage, the Complainant had to spend over $100.00 to get the system working again.

12. BHIU resumed billing the Complainant for service after his system was repaired and the circuit breaker reinstalled. On May 2 1990, BHIU sent a letter to the Complainant stating that he owed $247.10 for sewer service for the period from August 1, 1989, to March 31, 1990.

DISCUSSION AND CONCLUSIONS

The evidence for the above findings of fact comes from the testimony of the Complainant, John C. Newton, his wife, Alice C. Newton, BHIU's witnesses, David Edwards and Michael Kent Mitchell, exhibits entered into evidence at the hearing and the Commission's official files and records including the application by BHIU for a franchise filed on June 18, 1984, in Docket No. W-798.

The main issue the Complainant has brought before the Commission is whether or not he is a customer receiving sewer service from BHIU and, thereby, required to pay the Commission approved rates. The Complainant contends that he does not receive sewer service from BHIU because he is served by a low pressure type septic tank system he had installed at his own expense when he built his residence. The Complainant further contends that he has not signed any contract or HUD report agreeing to either turn his system over to BHIU or to pay BHIU to maintain his sewer system. Also, the Complainant contends that his system should be "grandfathered" like other systems installed by individuals prior to BHIU obtaining a franchise from the Commission.

BHIU contends that the Complainant is a customer receiving sewer service and is required to pay rates approved by the Commission. BHIU contends that it is obligated under its DEM permit to monitor and maintain all sewer systems constructed on Bald Head Island except the standard conventional septic tank systems installed for initial residents on the island and not covered under a DEM permit.

After careful examination of the evidence in the record, the Commission concludes that the Complainant is not obligated to receive sewer service from BHIU and, therefore, is not obligated to pay sewer rates to BHIU. The Commission notes that there was no evidence presented of any contract existing between the Complainant and BHIU which would indicate that Complainant had ever agreed for BHIU to provide him service. In addition, it is important to note that the system is entirely on the Complainant's own property and was paid for solely by Complainant. The evidence shows that BHIU didn't have a franchise at the time the Complainant built and moved into his house. Based on the facts of this case, the Commission concludes that the Complainant owns his own system and is not a customer of BHIU.

Based on the conclusion that the Complainant is not a customer of BHIU, it follows directly that BHIU did not have authority to charge the Complainant rates under the guise of his being a utility customer. Consequently, the Commission finds and concludes that BHIU should refund to the Complainant all the monies he has paid to BHIU since March 1, 1988, with interest at 10% per annum. This refund covers the last three years from the actual filing date of the complaint, the amount not barred by the statute of limitations.

The Complainant asserts that he is fully aware of the ramifications of the relief he has requested. As a result of this Order, BHIU will have no obligation or duty whatsoever to repair or maintain the Complainant's system. The Complainant will be responsible for securing all environmental and other permits, if any, which may be required for his sewer system. Should the Complainant desire utility service from BHIU at some time in the future, he will be required to pay the approved tap-on fee then in effect.

The Commission wishes to address one other concern--that is, BHIU disconnected service to the Complainant without giving the Complainant notice that his service had been disconnected. BHIU stated that it complied with the Commission's requirements and gave written notice prior to disconnection; and, consequently, it did not have to give the Complainant written notice when it actually disconnected his service. The Commission notes that we are dealing with a special type of service in this case, that is, a low pressure septic service where it is not readily ascertainable when service is disconnected. Here service was disconnected, and the customer did not know of such disconnection until damage to his system had occurred. Given the health risk and damage that can occur when sewage back ups, the Commission concludes that BHIU shall give written notice of disconnection whenever it cuts off a customer's low pressure septic service. This notice shall explain the health risk and danger that can occur due to service being disconnected.

IT IS, THEREFORE, ORDERED as follows:

1. That BHIU shall cease and desist from billing Complainant for sewer service.

2. That BHIU shall make a refund to the Complainant of all amounts he has paid to BHIU since March 1, 1988, including interest at 10% per annum. BHIU shall notify the Commission once the required refund has been made.

3. That BHIU shall give notice to customers when it has terminated their sewer service for non-payment. This notice is in addition to any and all notices required prior to service disconnection.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-950, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
A. K. Parrish,
Complainant
vs.
Falls Utility Company,
Respondent

FINAL ORDER OVERRULING EXCEPTIONS AND AFFIRMING RECOMMENDED ORDER

ORAL ARGUMENT HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Tuesday, February 19, 1991, at 9:30 a.m.

BEFORE: Commissioner Laurence A. Cobb, Presiding, and Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, Robert O. Wells, Charles H. Hughes

APPEARANCES:

For the Complainant:

A. K. Parrish, appearing pro se, 12033 Falls of the Neuse Road, Wake Forest, North Carolina 27587

For the Respondent:

David Smoot, President, Falls Utility Company, appearing pro se, 1011 East Whitaker Mill Road, Raleigh, North Carolina 27608

For the Attorney General:

Lorinzo L. Joyner, Assistant Attorney General, North Carolina Department of Justice, Utilities Division, Post Office Box 610 610, Raleigh, North Carolina 27602
For: The Using and Consuming Public

BY THE COMMISSION: On January 7, 1991, Commission Hearing Examiner J. Daniel Long entered a Recommended Order in this docket ruling on the complaint filed by Mr. A. K. Parrish (Complainant) against the Falls Utility Company (Respondent). The Hearing Examiner held that Mr. Parrish should be required to pay the Respondent the sum of $132.15 in equal amounts over a five-month period added to the monthly bill, beginning with the next billing cycle, as complete satisfaction of sums owed in arrears for water and sewer service.

The Respondent filed certain exceptions to the Recommended Order on January 22, 1991, and requested the Commission to schedule an oral argument to consider those exceptions. By Order dated January 31, 1991, the Commission scheduled an oral argument for February 19, 1991. The matter was thereafter called for oral argument at the appointed time and place. The Complainant, Respondent, and the Attorney General presented arguments in support of their respective positions.

WHEREUPON, the Commission reaches the following

CONCLUSIONS

The record in this proceeding fully supports the decretal paragraph and each of the findings of fact and conclusions set forth in the Recommended Order. Accordingly, the Commission finds good cause to deny the exceptions filed by the Respondent and hereby adopts the Recommended Order as the Final Order of the Commission.

IT IS, THEREFORE, ORDERED as follows:

1. That the exceptions to the Recommended Order filed by the Respondent on January 22, 1991, be, and the same are hereby, overruled and denied.

2. That the Recommended Order entered in this docket on January 7, 1991, be, and the same is hereby, affirmed and adopted as the Final Order of the Commission.

ISSUED BY ORDER OF THE COMMISSION.
This the 22nd day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

Commissioner Charles H. Hughes dissents.
Commissioner Laurence A. Cobb dissents.
Chairman William W. Redman, Jr., did not participate in this case.

DOCKET NO. W-177, SUB 31

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Brookwood Water Corporation, Post Office Drawer 4889, Cary, North Carolina, for Authority to Increase Rates for Water Utility Service in all its Service Areas in North Carolina	FINAL ORDER ON EXCEPTIONS MODIFYING RECOMMENDED ORDER

ORAL ARGUMENT HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on June 25, 1991, at 2:00 p.m.

BEFORE: Chairman William W. Redman, Jr., Presiding, and Commissioners Sarah Lindsay Tate , Julius A. Wright, Robert O. Wells, Charles H. Hughes and Laurence A. Cobb

APPEARANCES:

For Brookwood Water Corporation:

Robert F. Page, Attorney at Law, Crisp, Davis,Schwentker, Page and Currin, Post Office Drawer 30489, Raleigh, North Carolina 27622

For the Using and Consuming Public:

Victoria O. Hauser, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27627-0520

BY THE COMMISSION: On May 7, 1991, Commission Hearing Examiner Jim Panton entered a Recommended Order in this docket granting Brookwood Water Corporation (Brookwood, Applicant or Company) a partial rate increase in its water rates and charges to customers in all of its service areas in North Carolina.

On May 20, 1991, Brookwood filed certain exceptions to the Recommended Order Granting Partial Rate Increase and requested the Commission to schedule an oral argument to consider those exceptions.

By Order entered in this docket on May 23, 1991, the Commission scheduled an oral argument on exceptions for June 25, 1991, at 2:00 p.m.

The matter subsequently came on for oral argument on exceptions at the appointed time and place. Robert F. Page, counsel for the Company, offered oral argument in support of Brookwood's exceptions. Victoria O. Hauser, counsel for the Public Staff, offered oral argument in opposition to the exceptions and in support of the Recommended Order.

Brookwood's exceptions relate to the Hearing Examiner's findings and conclusions which allowed $113,088 to be treated as cost-free capital and deducted from the company's original cost rate base. The Applicant contends that the $113,088 was collected through fixed and established rates and should not be treated as cost-free capital in this and future cases.

The amount in question, $113,088, relates to the Company's collection of annual depreciation expense of $14,136 over an eight year period, 1974 through 1981, which is associated with plant or property which had been contributed to Brookwood.

On September 21, 1973, Brookwood filed for a general increase in its rates and charges in Docket No. W-177, Sub 11. By Order issued in that case on January 17, 1974, the Commission approved rates which reflected the inclusion of the $14,136 of depreciation expense on contributed property in the Company's cost of service. The Commission's final Order in Brookwood's Docket No. W-177, Sub 11, case was never appealed.

About one year later, by its decision in Utilities Commission v. Heater Utilities, Inc., 288 N.C. 457 (1975), the North Carolina Supreme Court ruled that the Commission could not allow, in rates, annual depreciation expense on contributed property. The Supreme Court in the Heater decision stated that the case was one of "first impression." That is, the issues raised in the case had never been decided previously by any North Carolina appellate court. Brookwood was not a party to the Heater case and the rates set by the Commission in the Docket No. W-177, Sub 11, case became fixed and established more than a year before the Heater decision was announced. Furthermore, after Heater was decided, no party sought any modification to Brookwood's Docket No. W-177, Sub 11, rates in which the Commission allowed depreciation on contributed property.

Subsequently, on March 17, 1982, Brookwood filed its next general rate case application in Docket No. W-177, Sub 17. According to the discussion included in the Recommended Order issued in that docket, the Company made adjustments in its 1982 rate case application to remove depreciation expense from the cost of service that was related to contributed plant and also proposed that a corresponding adjustment be made to reduce the end-of-period accumulated depreciation balance. The Public Staff made a similar adjustment to depreciation expense but did not remove from the accumulated depreciation balance contributed capital that was recovered through rates since the Company's last general rate case proceeding. The Public Staff argued that since the Company had been allowed to collect depreciation on contributed capital through rates established in the last general rate case, then these monies should be reflected in accumulated depreciation and deducted from the Company's original cost of plant in service. In Docket No. W-177, Sub 17, the Hearing Examiner found that the Company had been allowed in its last general rate case to recover through depreciation rates capital that had been contributed to the Company at no cost to the Company and concluded that this collection in the amount of $113,088 should be deducted from rate base as cost-free capital. The parties in Docket No. W-177, Sub 17 did not appeal or seek reconsideration from the Hearing Examiner's Recommended Order.

Brookwood concedes that, in the absence of any request for reconsideration or appeal, the rates set in Docket No. W-177, Sub 17, became fixed and established by operation of law and that the decision in that case to treat the amount of $113,088 as cost-free capital, even if based on an error of law, is binding and not subject to any sort of retroactive remedy or collateral attack.

Now we come to the Applicant's October 8, 1990, general rate case application in Docket No. W-177, Sub 31. In this docket, the Public Staff recommended that the sum of $113,088 be treated as cost-free capital, as had been done in the Company's preceding rate case. The Applicant opposed this recommendation and stated that on this issue the Hearing Examiner made a substantive error of law in Docket No. W-177, Sub 17 which should not be repeated in this case or in future Brookwood rate cases. As previously noted, the Company did not appeal the decision entered in its preceding rate case. However, since then the Company has come under new ownership; its stock was transferred to Heater Utilities, Inc. Now the Company objects to the decision allowed in its prior rate case being continued. The Company contends that the continued application of the $113,088 rate base reduction amounts to ongoing retroactive (ex post facto) ratemaking. The Hearing Examiner found in Docket No. W-177, Sub 31 that it was once again appropriate to treat the $113,088 as cost-free capital and the Company filed exceptions to this conclusion.

Retroactive ratemaking has been defined as a situation where ". . . an additional charge is made for past use of utility service or the utility is required to refund revenues collected, pursuant to then lawfully established rates, for such past use." Utilities Commission v. Nantahala Power and Light Company, 326 N.C. 190, 388 S.E. 2d 118, 127 (1990), quoting Utilities Commission v. N. C. Natural Corp., 323 N.C. 630, 641, 375 S.E.2d 147, 153 (1989). See also Utilities Commission v. Edmisten, 291 N.C. 451, 232 S.E.2d 184 (1977). "Prospective rate making to recover unanticipated past expense or to recover expected past expense which did not materialize, is as improper as is retroactive rate making." Edmisten, supra, 232 S.E. 2d at p. 195 (other citations omitted).

In the Docket No. W-177, Sub 11, case, rates were fixed and established to allow Brookwood to collect $14,136 in annual revenue associated with depreciation on contributed property. During the period of time that the Docket No. W-177, Sub 11, rates were in effect, from 1974 through 1981, Brookwood could not lawfully have charged any other rates. After the rates were set in the Docket No. W-177, Sub 11, case, the North Carolina Supreme Court in the Heater case ruled that utilities could not properly be allowed to charge rates or collect revenues attributable to annual depreciation expense on contributed property. Following the Heater decision, no party, including the Commission, the Public Staff, and the Company, requested reconsideration or any adjustment in the rates set for Brookwood in the Docket No. W-177, Sub 11, rate case. Brookwood continued to charge the lawful rates approved in Docket No. W-177, Sub 11.

Had the Commission issued an Order, after the Heater decision, that Brookwood's future rates would be reduced to eliminate from the revenue requirement that portion related to the depreciation expense on the contributed plant or that future funds collected should be placed into a deferred account and subject to refund, the principle of retroactive ratemaking would not apply. That action would have closely resembled what the Commission did in Docket No. M-100, Sub 113, in response to the Tax Reform Act of 1986. However, any such proposed reduction to future rates would have also given Brookwood the opportunity to apply for a rate increase to place the Company in a better financial position. Brookwood relied on the rates approved in Docket No. W-177, Sub 11, as being properly "fixed and established."

Based on the case law discussed above, the Commission concludes that the proposed reduction to rate base of $113,088 as cost-free capital would violate the principle against retroactive ratemaking and should be denied in this case.

Nevertheless, in accordance with our conclusion that the rates and charges approved in Docket No. W-177, Sub 11, were lawfully established, the Commission finds that the level of depreciation expense included in the cost of service in that docket, and collected through rates by the Company during the eight years, from 1974 through 1981, results in an increase of $113,088 in the Company's reserve for accumulated depreciation. Thus, the Commission finds it appropriate to treat the $113,088 amount in question as accumulated depreciation rather than as cost-free capital in recognition of the fact that this amount was collected through rates as depreciation expense. This $113,088 level of accumulated depreciation is related to certain utility plant which had been contributed to the Company rather than purchased by the Company but, nevertheless, it is accumulated depreciation. Recognition of this $113,088 as accumulated depreciation rather than as cost-free capital will have the same impact on the Applicant's revenue requirement as did the Hearing Examiner's conclusion to treat the $113,088 as cost-free capital. Under either of these scenarios, the Applicant's original cost rate base will be reduced by $113,088. The treatment of the $113,088 as accumulated depreciation is also consistent with the treatment which was initially proposed by the Public Staff in Docket No. W-177, Sub 17. It is also the ratemaking treatment which should have been adopted in that case.

In summary, the Commission finds that the $113,088 which has been classified by the Hearing Examiner as cost-free capital should be reclassified and treated as accumulated depreciation. The Commission also finds that the interim rates currently being charged by the Applicant are the appropriate ongoing rates and are no longer subject to refund.

IT IS, THEREFORE, ORDERED as follows:

1. That the May 7, 1991 Recommended Order issued in this docket shall be, and hereby, is affirmed, except as modified herein, to include $113,088 in the Company's original cost rate base as accumulated depreciation rather than as cost-free capital.

2. That Brookwood Water Corporation is authorized to increase its rates for water utility service to produce additional annual gross service revenues of $164,048, which is the amount found fair in the May 7, 1991 Recommended Order issued in this docket.

3. That the Schedule of Rates attached as Appendix A is approved for water utility service rendered by Brookwood Water Corporation on and after the effective date of this Order. This schedule is deemed filed pursuant to G.S. 62-138.

4. That Brookwood Water Corporation shall deliver a copy of the Notice attached as Appendix B to all of its customers with their next billing statements.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

SCHEDULE OF RATES
for
BROOKWOOD WATER CORPORATION
for providing water utility service in
ALL ITS SERVICE AREAS
in North Carolina

METERED RATES: (monthly)

Base monthly charge for zero consumption

< 1" meter	$ 3.02
1" meter	$ 7.55
2" meter	$24.16
3" meter	$45.30

Commodity Charge - $1.00 per 1,000 gallons

FLAT RATE: $6.60 per month

(Note: Meters may be installed and the applicable metered rate charged.)

TAP FEE: $450.00

RECONNECTION CHARGES:

If water service cut off by utility for good cause: $15.00
If water service discontinued at customer's request: $ 7.50

NEW CUSTOMER ACCOUNT FEE: $ 8.00

RETURNED CHECK CHARGE: $10.00

BILLING FREQUENCY: Monthly for service in arrears

BILLS DUE: On billing date

BILLS PAST DUE: Fifteen (15) days after billing date

FINANCE CHARGE FOR LATE PAYMENTS: 1% per month will be applied to the unpaid balance of all bills still past due twenty five (25) days after billing date.

Issued in accordance with authority granted by the North Carolina Utilities Commission in Docket No. W-177, Sub 31 on this 15th day of July, 1991.

APPENDIX B

DOCKET NO. W-177, SUB 31

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Brookwood Water Corporation, Post Office Drawer 4889, Cary, North Carolina, for Authority to Increase Rates for Water Utility Service in all its Service Areas in North Carolina) NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an order authorizing Brookwood Water Corporation a permanent increase in its rates. Customers will not experience an increase in their bills because the approved rates are the same as the interim rates granted on March 28, 1991. The approved rates are as follows:

METERED RATES: (monthly)

Base monthly charge for zero consumption:

Meter Size	Charge
< 1"	$ 3.02
1"	$ 7.55
2"	$24.16
3"	$45.30

Usage Charge (all meter sizes) $1.00 per 1,000 gallons

FLAT MONTHLY RATES: $6.60

(Note: Meters may be installed and the applicable metered rate charged.)

These rates were granted after public hearings in Fayetteville and Raleigh on February 27, 1991 and March 13, 1991, respectively.

ISSUED BY ORDER OF THE COMMISSION.
This the 15th day of July, 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-274, SUB 59

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Heater Utilities, Inc., Post Office Drawer 4889, Cary, North Carolina, for Authority to Increase Rates for Water Utility Service in All Its Service Areas in North Carolina	ORDER DENYING MOTION FOR RECONSIDERATION AND REAFFIRMING ORDER OF DECEMBER 20, 1990

BY THE COMMISSION: On December 20, 1990, the Commission issued Order Granting Partial Rate Increase in this docket.

On January 18, 1991, the Public Staff filed Motion for Extension of Time to File Notice of Appeal in this docket and also Motion for Reconsideration.

By Order of January 22, 1991, the Commission issued its Order Granting Extension of Time to File Notice of Appeal. The Order extended the time to file appeal to and including Monday, February 18, 1991, as requested by the Public Staff.

On February 12, 1191, Heater Utilities, Inc., filed its Response to Public Staff Motion for Reconsideration.

The Public Staff, in its Motion, requested the Commission to amend its Order of December 20, 1990, in the following respects:

1. To allocate the $76,823 net-of-tax gain on the abandonment of the Ossipee system and the sale of Maplewood/Ravenwood/Tiffany Gardens system equally between Heater's stockholder and ratepayers.

2. To require Heater to refund the entire $32,997 that it over-collected from its former Heater-only customers due to the Tax Reform Act of 1986 to its former Heater-only customers.

The Public Staff asserts that regardless of whether the gain on sale issue was raised in the Maplewood/Ravenwood/Tiffany Gardens transfer docket, and regardless of whether the transfer was approved prior to April 10, 1990, it is uncontroverted that Heater and its ratepayers shared in the risk associated with the utility property. The Public Staff stated its position to be that Heater's stockholders should recover its rate base and 50 percent of the net gain on the sale in addition to having been compensated for risks through Heater's authorized rate of return. With respect to the TRA-86 overcollections, the Public Staff also took issue with the Commission's handling of this matter in the December 20, 1990 Order.

On February 12, 1991, Heater filed its Response to the Public Staff Motion and contended that the Public Staff's Motion for Reconsideration should be denied and that the Commission's Order of December 20, 1990, should be affirmed in all respects. With respect to the gain on sale issue, Heater contended that the

Commission properly refused an ex post facto treatment on the gain on sale issue. With respect to the TRA-86 overcollections, Heater also contended that the Commission properly considered this matter and reached the correct decision.

Upon consideration of the Public Staff Motion for Reconsideration, the Response of Heater thereto, and the Commission's Order of December 20, 1990, the Commission is of the opinion that this Order should issue denying the Motion for Reconsideration and reaffirming the Commission's Order of December 20, 1990. The Commission is of the opinion that its December Order amply explains the reasons for its decision on these two issues, and it would not be of advantage to repeat them here. The Commission will emphasize, however, its reasoning that it would be inequitable to apply any gain on sale order retroactively to transfers which occurred prior to the April 10, 1990 filings in Docket No. W-354, Subs 82, 86, 87, and 88, and subsequent Order dated October 16, 1990. By the time the October 16, 1990 Order was issued, the contract between Heater and the City of Goldsboro had been negotiated, executed and submitted to and approved by the Commission. Having given its approval to Heater as to the subject transfers, it would be inequitable for the Commission to reopen the transfer docket and retroactively apply any benefits of gain on sale.

With respect to the TRA-86 overcollections, the Commission is of the opinion that its findings and conclusions on that issue should likewise be reaffirmed.

IT IS, THEREFORE, ORDERED as follows:

1. That the Motion for Reconsideration of the Public Staff, filed January 18, 1991, be denied.

2. That the Order of the Commission issued in this docket on December 20, 1990, be reaffirmed in all respects.

ISSUED BY ORDER OF THE COMMISSION.
This the 18th day of February 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Acting Chief Clerk

DOCKET NO. W-279, SUB 22
DOCKET NO. W-225, SUB 20

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Cape Fear Utilities, Inc.,	)	
and Quality Water Supplies, Inc., Post	)	ORDER
Office Box 424, Wrightsville Beach,	)	APPROVING
North Carolina 28480, for Authority	)	PARTIAL
to Increase Its Rates for Providing	)	INCREASE
Water Utility Service in All Their	)	IN RATES
Service Areas in North Carolina	)	

HEARD IN: Superior Courtroom #317, New Hanover County Courthouse, Fourth and Princess Streets, Wilmington, North Carolina, on January 17, 1991, at 7 p.m.

BEFORE:. Commissioner Laurence A. Cobb, Presiding, Commissioner Charles H. Hughes, and Commissioner Julius A. Wright

APPEARANCES:

For the Applicants:

William E. Grantmyre, Attorney at Law, Post Office Drawer 4889, Cary, North Carolina 27511

For the Using and Consuming Public:

Robert B. Cauthen, J., Staff Attorney, Public Staff North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27262-0520

BY THE COMMISSION: On April 4, 1990, Quality Water Supplies, Inc. (Quality), filed an application for a general rate increase. By Order issued May 1, 1990, the Commission declared the application to be the general rate case, suspended the proposed rates, required public notice, and scheduled a hearing for August 30, 1990.

On July 13, 1990, the Public Staff filed a motion requesting that Quality update its test year to the period ending December 31, 1989, that the hearing for Quality scheduled for August 30, 1990, be rescheduled because notice was not given timely, and that it was also necessary for the Public Staff to investigate the books and records of Cape Fear Utilities, Inc. (Cape Fear). Quality agreed with the Public Staff that public notice of the August 30, 1990, hearing had not been given timely and agreed to the rescheduling of the hearing. The Commission by Order dated August 7, 1990, rescheduled the hearing to November 29, 1990.

On October 3, 1990, Cape Fear filed an application for general rate increase. Included in this application is Masonboro Utilities, Inc., a wholly owned subsidiary of Cape Fear. Also, on October 3, 1990, Quality filed a motion to consolidate its general rate increase application with the Cape Fear application. Quality also filed updated financial data and requested the Commission to update the test year to the period ending December 31, 1989.

By Order dated October 25, 1990, the Commission established the Cape Fear application as a general rate case, suspended Cape Fear's proposed rates, consolidated the applications of Cape Fear and Quality, cancelled the November 29, 1990, hearing, scheduled a public hearing for January 17, 1991, and required public notice.

On January 11, 1991, Cape Fear and Quality executed a stipulation with the Public Staff and filed the stipulation with the Commission. In this stipulation, Cape Fear, Quality, and the Public Staff stipulated to the revenue requirement, the rate schedule, the future gross up factor, and that the quality of service of Quality and Cape Fear is adequate.

At the public hearings on January 17, 1991, three public witnesses testified. The public witnesses were Charles F. Bove', Eugene Langone, and Richard Harris. Quality and Cape Fear presented the testimony of Bill Dobo, president of Quality and an officer of Cape Fear.

Based on the information contained in the Commission files, the verified applications, the testimony at the hearing, the stipulation of the parties, and the entire record in this proceeding, the Commission now makes the following:

FINDINGS OF FACT

1. Quality Water Supplies, Inc., and Cape Fear Utilities, Inc. are public utilities as defined by G.S. § 62-3(23) and, as such, are subject to the jurisdiction and regulation of the North Carolina Utilities Commission. Quality and Cape Fear are lawfully before the Commission seeking an increase in their rates and charges pursuant to G.S. § 62-133.

2. Cape Fear and Quality have Certificates of Public Convenience and Necessity to furnish water utility service in their service areas in North Carolina. Cape Fear also provides sewer utility service but did not apply for an increase in rates in this proceeding.

3. The test period established for use in this proceeding is the 12-month period ended December 31, 1989.

4. The net utility plant in service, operating revenues, and operating revenue deductions of Cape Fear and Quality were considered on a consolidated basis for the purposes of determining the revenue requirement and rates.

5. The quality of water service provided by Quality and Cape Fear is adequate.

6. The proposed water rates of Quality and Cape Fear are excessive and should be disallowed.

7. The Public Staff has conducted a complete investigation of Quality and Cape Fear's rate base, reasonable operating revenue deductions, and operating revenues.

8. The Public Staff, Quality, and Cape Fear have stipulated that, based on the Public Staff's investigation, a revenues requirement of $962,090 is just and reasonable to provide a reasonable return to Quality and Cape Fear.

9. The Public Staff, Quality, and Cape Fear stipulated that the following rates should produce the agreed upon revenue requirement:

Base charge (based on meter size)

3/4"	$ 5.00
1"	12.50
1-1/2"	25.00
2"	40.00
3"	80.00
4"	125.00
6"	250.00

Commodity Charge: $ 1.28/1,000 gallons

10. That Quality and Cape Fear stipulated with the Public Staff that Quality and Cape Fear shall begin calculating the gross up factor applicable to the tap fees using an expected federal marginal tax rate no greater than 34%.

11. That the rates contained in Appendix A, attached hereto, will result in satisfying Quality and Cape Fear's revenue requirements.

From a review and study of the application; the evidence presented at the hearing; supporting material; the stipulation of Quality, Cape Fear, and the Public Staff; and other information in the Commission files, the Commission reaches the following

CONCLUSIONS

1. The evidence supporting Findings of Fact Nos. 1, 2, 3, and 4 are contained in the verified applications and the testimony presented by Quality and Cape Fear. These findings are essentially information, procedural, and jurisdictional in nature and were uncontested.

2. Finding of Fact No. 5 is supported by the testimony of Quality and Cape Fear witness Bill Dobo and the public witnesses.

The only public witness who testified concerning service was Richard Harris who testified that it took Quality a long time to install a meter at a community pool.

Public witnesses Harris and Bove' testified against the rate increase. Public witness Langone testified that, after discussing the case with the Public Staff, he was satisfied with the stipulation of the Public Staff, Quality, and Cape Fear.

Based upon the foregoing, the Commission concludes that the quality of service of Cape Fear and Quality is adequate.

3. Evidence supporting Findings of Fact Nos. 6 and 7 are found in the verified applications of Quality and Cape Fear, the testimony of Quality and Cape Fear witness Bill Dobo, and the stipulation filed by the parties.

4. The evidence supporting Findings of Fact Nos. 8, 9, and 10 are found in the stipulation of Quality, Cape Fear, and the Public Staff filed in this proceeding.

5. Evidence for Finding of Fact No. 11 is contained in the verified applications of Quality and Cape Fear and the stipulation filed by the parties.

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 of Quality and Cape Fear's customers in conjunction with the next regularly scheduled billing process.

3. That Quality and Cape Fear shall begin calculating the gross factor applicable to tap fees using an expected federal marginal tax rate no greater than 34%.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of January 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

APPENDIX A

SCHEDULE OF RATES
for
CAPE FEAR UTILITIES, INC.
(includes Masonboro Utilities, Inc.) and
QUALITY WATER SUPPLIES, INC.
for providing water and sewer utility service
in All Their Service Areas
in North Carolina

WATER RATES

Base charge: (based on meter size)

Meter Size	Base Charge
3/4"	$ 5.00
1"	12.50
1-1/2"	25.00
2"	40.00
3"	80.00
4"	125.00
6"	250.00

Usage Charge: $ 1.28/1,000 gallons

WATER AND SEWER - RATES

SEWER RATES:

Residential: $20.00/month

Nonresidential: 200% of metered water rate

Connection Fees: Water: $ 700.00
Sewer: $1,200.00
(These fees are also subject to the gross-up.)

Reconnection Charges:

If water service cut off by utility for good cause:	$15.00
If water service discontinued at customer's request:	$ 2.00
If sewer service cut off by utility for good cause:	$15.00

New Account Charge: $5.00

Return Check Charge: $15.00

Deposit:

Water only	$25.00
Water and sewer	$65.00
Sewer only	$40.00

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be monthly, for service in arrears

Finance Charge for Late Payment: 1% per month will be applied to the unpaid balance of all bills still past due 25 days after billing date.

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket Nos. W-279, Sub 22, and W-225, Sub 20, on this the 31st day of January 1991.

APPENDIX B

DOCKET NO. W-279, SUB 22
DOCKET NO. W-225, SUB 20

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Cape Fear Utilities, Inc., and Quality Water Supplies, Inc., Post Office Box 424, Wrightsville Beach, North Carolina 28480, for Authority to Increase Its Rates for Providing Water Utility Service in All Their Service Areas in North Carolina) NOTICE TO CUSTOMERS

NOTICE IS HEREBY GIVEN that the North Carolina Utilities Commission has issued an Order authorizing Cape Fear Utilities, Inc., and Quality Water Supplies, Inc., to charge increased rates for water service to all of their customers in North Carolina. The rates are shown on the attached Appendix A.

The Commission issued its decision following a public hearing in Wilmington on January 17, 1991.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of January 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Acting Chief Clerk

(SEAL)

DOCKET NO. W-354, SUB 74
DOCKET NO. W-354, SUB 79
DOCKET NO. W-354, SUB 81

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Carolina Water Service, Inc., of North Carolina 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Providing Water and Sewer Service in All Its Service Areas in North Carolina) ORDER ON CLARIFICATION

BY THE COMMISSION: On September 7, 1990 Carolina Water Service, Inc., of North Carolina (Company, Applicant, CWS), filed its motion for Clarification requesting that the Commission clarity its Order Granting Partial Rate Increase, dated June 15, 1990, as it related to refunds resulting from the Tax Reform Act of 1986 (TRA-86). Subsequently, the Public staff filed response to CWS's Motion for Clarification and on October 17, 1990, the Company filed a reply to the Public Staff's response.

The Commission's Order on June 15, 1990, required CWS to reduce its rates from the level otherwise approved for a one-year period by $331,686. This amount was provided by the Company during the public hearing in this proceedings. Since this amount had not been agreed to by the Public Staff, the Commission concluded that should the Public Staff determine that the amount was too low, then the Public Staff should file recommendations with the commission concerning any additional rate reductions or refunds related to TRA-86 savings and interest.

Subsequent to issuance of the Order, the Company filed Motion for Clarification wherein the Company proposed, among other things, that the refund amount should be revised downward to $246,961. In its response, the Public Staff asserts that the amount should be revised upward to $348,627. The difference between the parties is $101,666, as itemized in the chart below:

Item	Amount
Difference in over-collection period	$ 77,175
Interest during refund period	16,601
Notification costs deducted by Company	7,890
Total	$101,666

The major difference of $77,175 is over the date upon which the Company's revenues are no longer subject to refund. The Company calculates the over-collection from January 1, 1987, to September 15, 1988, the date interim rates in Docket No. W-354, Sub 69 became effective. The Public Staff calculates the over-collection from January 1, 1987, to February 7, 1989, the date of the Commission's Order Granting Partial Rate Increase in Docket No. W-354, Sub 69. In deciding which period is appropriate, the Commission must determine at what point were the Company's rates first adjusted for the TRA-86 tax rate decrease to 34%. The Company and the Public Staff both agree that this adjustment occurred as the result of the Company's general rate case filing in Docket No. W-354, Sub 69. This was the Company's first general rate case subsequent to the passage of TRA-86. The parties disagree, however, on the point in time that this adjustment actually took place.

The Company asserts that its rates were adjusted for the TRA-86 tax rate decrease when the interim rates were approved in Sub 69. The approved interim rates were one dollar per month for each water and sewer service, and were agreed to by both the Public Staff and the Company. The income statement filed by the Company in its application in Sub 69 included the impact of the TRA-86 tax rate decrease, and it is this statement that was relied on in part in approving the interim rates.

The public Staff asserts that the Company's rates were adjusted for the TRA-86 tax rate decrease when the final Order was issued and permanent rates were approved based on a fully audited cost of service that included the impact of the TRA-86 tax rate decrease. The public Staff asserts that the interim rates could be assigned to recover any cost of service item, therefore are not rates could be assigned to recover any cost of service item, therefore are not the reflection of any specific cost of service item, such as income taxes. No mention of the tax effects from TRA-86 are made in the Order approving interim rates.

The Commission has carefully reviewed this matter. The Commission notes that the Company's report filed May 24, 1989, in Docket No. M-100, Sub 113 shows TRA-86 tax over-collections through February 7, 1989, the final Order date in Sub 69. Therefore, the Company's filing in that docket supports the position of the Public Staff.

Based on the foregoing, the Commission concludes that the TRA-86 tax over-collections should be calculated through February 7, 1989, as proposed by the Public Staff. The Commission is unconvinced that TRA-86 tax effects were an ingredient in the interim rates agreed to by the parties in Sub 69. The interim rate increase is more properly viewed as a temporary increment, subejct to review and refund, to the rates previously approved by the Commission.

The next difference between the TRA-86 refund amounts proposed by the parties is due to the Public Staff's inclusion of interest during the refund period. The Commission has consistently calculated interest on refunds during the refund period in other proceedings. Therefore, the Commission concludes that interest should be calculated on the TRA-86 refunds during the refund period in this proceeding, as proposed by the Public Staff.

The last difference between the TRA-86 refund amounts proposed by the parties is due to the Company's deduction of the cost of public notices to be issued when the refund period expires. The Public Staff contends that the Commission has not allowed this type of refund offset for other companies and that the customer notcie costs should be viewed as an item of the Company's cost of service in the period incurred. The Commission agrees with the position of the Public Staff. The Commission recognizes that this type of offset was not allowed for other companies refunding TRA-86 over-collections.

Based on all the foregoing, the Commission concludes that the proper TRA-86 refund amount is $348,627, as recommended by the Public Staff.

In its Motion for Clarification the Company expressed concerns that the approved refund procedure might result in refunds greater than the determined refund liability. The Company pointed out that any increased consumption during the one year refund period over the consumption levels used by the Commission in establishing the refund factor would result in a refund greater than the determined liability. The Company further stated that it has experienced wide spread growth in its system and anticipates that such growth will continue during the refund period. In order to refund an amount closer to the determined liability, the Company requests permission to submit consumption billing data some time prior to June 15, 1991, in order to implement new rates.

The Commission has carefully reviewed the proposal of the Company to submit consumption billing data and concludes that it is reasonable. Clearly, the main intent is that the over-collection be refunded to customers. Therefore, the Commission concludes that the Company should track the refund using actual billing data and provide 30 days notice to the Commission when the refund period should end. Thirty days after the end of the refund period the Company should file a report showing the amount actually refunded to customers. The Commission notes that since the refund liability has been increased above the amount approved in the June 15, 1990, Order, and since the Company is being allowed to track said refund based on actual billing data, then the refund period may be shorter or longer than one year.

The Commission wishes to take the time here to respond to the Company's letter of July 12, 1990, filed with the Chief Clerk. The Company addresses the methodology employed by the Commission in its June 15, 1990, Order in regards to adjustments made for excess plant and acquisition adjustments. The Company's letter does not request modification of the Commission's Order. The Commission concludes that the Order of June 15, 1990, clearly reflects the evidence presented on these matters in this proceeding. The decisions in this proceeding are based on this evidence. The Commission is well aware that many of the issues addressed in this proceeding will be subject to investigation and presentation of evidence in future general rate cases. The decisions in these future cases will be based on the evidence presented at that time and the calculations made in this proceeding should not be considered as precedents.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's rates should remain in effect until $384,627 is refunded to customers.

2. That the Company should provide 30 days notice to the Commission prior to removal of the refund factor from present rates.

3. That the Company should file a report showing actual refunds made to customers within 30 days of the end of this refund period.

ISSUED BY ORDER OF THE COMMISSION.
This the 7th day of January 1990.

NORTH CAROLINA UTILITIES COMMISSION
Sandra J. Webster, Chief Clerk

(SEAL)

DOCKET NO. W-371, SUB 1

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Bogue Banks Water and Sewer Company for a Certificate of Public Convenience and Necessity to Furnish Water Utility Service in Emerald Isle, Indian Beach, and Salter Path, Carteret County, North Carolina, and for Approval of Rates	ORDER APPROVING INITIAL RATES

HEARD: Thursday, April 11, 1991, at 7 p.m., Town Hall, Emerald Isle, North Carolina

BEFORE: Laurence A. Cobb, Presiding; Commissioners Julius A. Wright and Charles H. Hughes

APPEARANCES:

For Bogue Banks Water and Sewer Company:

Kenneth M. Kirkman, Kirkman, Whitford & Jenkins, P.A., Post Office Drawer 1347, Morehead City, North Carolina 28557

For the Public Staff:

James D. Little, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

BY THE COMMISSION: On March 20, 1991, Bogue Banks Water and Sewer Company (Bogue Banks, Applicant, or Company) and the Public Staff filed a Proposed Order agreeing on an initial rate design and, settling all issues regarding the regulation of this Company, subject to Commission approval. On March 25, 1991, the Commission entered an Order in this docket granting a Certificate of Public Convenience and Necessity to Bogue Banks to provide water utility service to the Towns of Emerald Isle, Indian Beach, and Salter Path in Carteret County, North Carolina. In that Order, the Commission scheduled a public hearing at the Town Hall, Emerald Isle, North Carolina, on Thursday, April 11, 1991, at 7 p.m. The Public Notice indicated that the Public Staff would be available one hour prior to the hearing to answer questions and explain the new rate design to the customer. The purpose of the hearing at 7 p.m. was to hear from customers. The Company was coming under the jurisdiction of the Commission for the first time, and this was a new rate design for the Company.

The hearing was held as scheduled. Three public witnesses testified. They were Hilton B. Peel, Wayne Yelverton, and Buck Fugate. Mr. Peel and Mr. Yelverton questioned why it was necessary for the Commission to regulate the Company and pointed out that the new rate design raised residential rates. Mr. Fugate questioned whether his new rate was correct. None of the witnesses had a criticism of the quality of service provided by the Company.

The Public Staff, through statements of counsel and through the testimony of Jan Larsen, a Utilities Engineer with the Public Staff's Water Division, and Todd Clapp, an Accountant with the Public Staff's Accounting Division, explained the Public Staff audit of the Company and recommended that the rate schedule agreed to by the Company be adopted. The rate design required approximately 35% of the revenue requirement to be placed on the base charge for zero usage and the remaining revenue requirement on the usage charge based on the gallons used each month. The Public Staff also commended the Company, its Board of Directors and its staff on its operations and the high quality of the physical plant. The Public Staff explained to the Commission that in 1990, as a result of the excellent condition of this non-profit company and the control by a non-paid, dedicated Board of Directors, the Public Staff halted further action for a period and encouraged the Board to attempt to persuade the General Assembly to exempt the Company from Commission jurisdiction. The Company was unsuccessful in its attempt.

The Commission notes that Mr. Larsen wrote a letter to Mr. Fugate dated April 18, 1991, explaining the Public Staff's calculation of Mr. Fugate's imputed meter size and that it was consistent with the rate design of other customers. Mr. Larsen pointed out that standards adopted by the North Carolina Division of Environmental Management, not actual water consumption, were the basis for determining meter size. The Commission notes that under this rate design customers who use less than the average usage will actually realize a saving since approximately 65% of the revenue requirement is built into the usage charge and only 35% in the base charge. The Commission would further note from Mr. Larsen's letter that even with the Company's increased revenue requirement, Mr. Fugate's bill should be reduced from $5,125 in 1990, to approximately $2,800 under the Public Staff's rate design.

Mr. John McLean and Mr. Larry Spell testified for the Company. Mr. McLean is President of the Board of Directors of the Company and Mr. Spell is on the Board. Mr. McLean and Mr. Spell both testified as to the reasons for the Company's previous rate design. Mr. McLean testified that the rate schedule currently being charged by the Company was based upon a peak demand concept (the water that was required to be provided by the system at peak tourist times. He further explained that the rate was applied consistently to all customers of the water system and was a rational and equitable rate schedule that was based on the high resort-oriented character of the community served.

After the hearing, the Company requested that two items be added to its tariff. One was a $15 New Customer Account Fee, and the other was a $25 Facilities Fee. The New Customer Account Fee is to offset the expense of opening a new customer's account, including unlocking the meter. The Facilities Fee will be charged to customers requesting that the Company put a temporary meter on a fire hydrant in order to fill a swimming pool or some similar facility. This is typically a once a year fee for the few customers requesting it. Such customers pay the usage charge in addition to the fee.

BASED ON THE FOREGOING, the Commission concludes:

1. That Bogue Banks Water and Sewer Company is a well run utility with a dedicated Board of Directors and professional staff.

2. That the rate design agreed to by the Company and the Public Staff is reasonable and in line with other regulated utilities, including the $15 New Customer Account Fee and the $25 Facilities Fee.

IT IS, THEREFORE, ORDERED as follows:

1. That the rate design agreed to by Bogue Banks Water and Sewer Company and the Public Staff and filed with this Commission on March 20, 1991, and the $15 New Customer Account Fee and the $25 Facilities Fee as set forth herein, is hereby approved for bills issued on or after May 1, 1991.

2. That a copy of this Order be delivered to all the customers of Bogue Banks in conjunction with the May 1, 1991 billing cycle, and that the Company submit to the Commission the attached Certificate of Service properly signed within 30 days.

ISSUED BY ORDER OF THE COMMISSION.
This the 3rd day of May 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

CERTIFICATE OF SERVICE

I, ______________________________, mailed with sufficient postage or hand delivered to all affected customers the attached Order issued by Order of the North Carolina Utilities Commission in Docket No. W-371, Sub 1, and said Order was mailed or hand delivered by the date specified in the Order.

This the _____ day of _______________ 1991.

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 Order was mailed or hand delivered to all affected customers, as required by the Commission Order dated ______________ in Docket No. W-371, Sub 1.

Witness my hand and notarial seal, this the ____ day of ______________ 1991.

____
Notary Public

____
Address

(SEAL) My Commission Expires: ______________________
Date

DOCKET NO. W-436, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application by Carolina Trace Corporation, Post Office Box 2250, Sanford, North Carolina 27330, for Authority to Increase Rates for Providing Water and Sewer Utility Service in Carolina Trace Subdivision in Lee County, North Carolina) FINAL ORDER ON EXCEPTIONS APPROVING RATES

ORAL ARGUMENT
HEARD IN: April 25, 1991, at 9:30 a.m., Commission Hearing Room, Dobbs Building, Raleigh, North Carolina

BEFORE: Chairman William W. Redman, Jr., Presiding; and Commissioners Sarah Lindsay Tate, Ruth E. Cook, Julius A. Wright, Robert O. Wells, Charles H. Hughes, and Laurence A. Cobb

APPEARANCES:

For Carolina Trace Corporation:

William E. Grantmyre, Attorney at Law, P.O. Drawer 4889, Cary, North Carolina 27511

For the Using and Consuming Public:

David T. Drooz, Staff Attorney, Public Staff - North Carolina Utilities Commission, P.O. Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: Carolina Trace Corporation (the Applicant, Carolina Trace or Company) filed an application for rate increase on June 28, 1990, for water and sewer utility service in Carolina Trace Subdivision, Lee County, North Carolina. The Commission issued an Order on July 17, 1990, declaring the case to be a general rate case, suspending the proposed rates, scheduling a hearing, and requiring public notice.

The Company filed some accounting exhibits with its application, but did not prefile testimony.

The Public Staff filed its Affidavit of George T. Sessoms, Jr., on October 22, 1990. On October 24, 1990, the Public Staff filed a Motion of Extension which asked that the Public Staff witnesses be allowed until October 30, 1990, to prefile testimony and exhibits. This motion was granted by the Commission. On October 30, 1990, the Public Staff filed the Supplemental Affidavit of George T. Sessoms, Jr., (Financial Analyst), and the testimony and exhibit of Katherine A. Fernald (Staff Accountant), and the testimony of Ronald D. Brown (Utilities Engineer).

Public Staff witness Brown testified at the hearing. The affidavit of Mr. Sessoms and the prefiled testimony and exhibit of Ms. Fernald were accepted into evidence by stipulation at the hearing. For the Company, Jocelyn Perkerson and Joe Brinn testified at the hearing, and Mr. Brinn sponsored exhibits as well.

The Company filed the following late-filed exhibits: (1) Tap-fee cost breakdown, filed December 10, 1990, (2) Contract between the City of Sanford and Carolina Trace Corporation, filed December 13, 1990, and (3) Insurance expense data, filed December 13, 1990. The Public Staff filed a late-filed exhibit on December 17, 1990, relating to corrected usage amounts and pro forma revenues.

A number of customers wrote protest letters to the Commission. At the hearing, Al Duensing, Barbara Jensen, Martha Cary, John Louer, Vincent Clayton, Bob Wolmering, David Jarred, Philip Voorhees, Beth Schuster, Bob Heath, Farley Fish, Nancy Goodwin, Robert Kratz, and William C. Bishop testified as customers of Carolina Trace in opposition to the proposed rate increase. They also testified as to brown discoloration in the water and other problems with the quality of the water and sewer service. Mr. Bishop proposed specific adjustments which are addressed below in Finding of Fact No. 13.

On January 29, 1991, the Examiner issued an Interlocutory Order granting as interim rates for the Company the rates proposed by the Public Staff in its Recommended Order.

On March 21, 1991, Hearing Examiner Partin issued Recommended Order Approving Rates.

On April 5, 1991, the Public Staff filed exceptions to the Hearing Examiner's Recommended Order of March 21, 1991. Carolina Trace filed Motion for Oral Argument and Recommended Rates Be Approved as Interim Rates on April 10, 1991.

By Order of April 19, 1991, the Commission scheduled oral argument to consider the exceptions filed by the Public Staff. On April 24, 1991, the Commission issued Order Disallowing Additional Interim Rate Increase wherein the Applicant's motion that the recommended rates be approved as interim rates was denied.

On April 25, 1991, the oral argument was held before the Commission.

Based upon the application, the testimony of the witnesses, the exhibits, and the record as a whole in this docket, the Commission makes the following :

FINDINGS OF FACT

1. The test period for use in this proceeding is the 12-months ended September 30, 1989.

2. The operating ratio methodology, which gives a margin on operating revenue deductions requiring a return, is the appropriate method of determining rates for water operations in this proceeding. The rate base methodology, which gives a return on original cost rate base, is the appropriate method of determining rates for sewer operations in this proceeding.

3. The Applicant's original cost rate base used and useful in providing sewer service is $526,099.

4. The Applicant's level of operating revenues for the test year, with pro forma adjustments and updates, under present rates is $109,181 for water operations and $102,422 for sewer operations.

5. The level of operating revenue deductions for the test year, with pro forma adjustments and updates, under present rates is $157,129 for water operations and $135,192 for sewer operations.

6. A margin of 11.5% on operating revenue deductions requiring a return for water operations is just and reasonable for the Applicant in this proceeding.

7. A rate of return of 11.5% on original cost rate base for sewer operations is just and reasonable for the Applicant in this proceeding.

8. The Applicant should be allowed an increase in annual operating revenues of $73,679 for water operations and $109,538 for sewer operations. The rates set forth in Appendix A will produce this increase and should allow the Applicant the opportunity to earn a return of 11.5% on both water and sewer operations.

9. The Applicant should account for tap-on fees and contributions in aid of construction in accordance with the Uniform System of Accounts for water and sewer companies published by the National Association of Regulatory Utility Commissioners.

10. The level of water utility service being provided is generally adequate; however, there are deficiencies requiring improvements as set forth subsequently herein. The level of sewer service is adequate.

11. The current sewer rate schedule has a provision to cap sewer charges at a maximum of 6000 gallons. It is fair and reasonable to continue this provision.

12. The proper tap fee for water service is $605 plus full gross up, and the proper tap fee for sewer service is $533 plus full gross up.

13. A number of adjustments were proposed by a customer knowledgeable in regulatory accounting and ratemaking, Mr. Bishop, on behalf of the Carolina Trace Association. These adjustments have been considered by the Commission in reaching a decision in this docket.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is found in the application for rate increase filed June 28, 1990, and in the testimony and exhibits of Public Staff witnesses Fernald and Brown. This finding is uncontested and uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 2

The evidence supporting this finding of fact is found in the application for rate increase filed June 28, 1990, the testimony and exhibit of Public Staff witness Fernald, and the affidavit of Public Staff witness Sessoms.

In its application, the Applicant used the operating ratio methodology for water operations and the rate base methodology for sewer operations. Witness Fernald also used these methodologies to determine the recommended revenue requirements for water and sewer operations, as shown in her exhibits. Witness Sessoms stated that the use of the operating ratio method provides for a more reasonable level of revenues for water operations since operating expenses exceed rate base. Conversely, use of the rate of return on rate base method provides a more reasonable level of revenues for sewer operations since rate base exceeds operating expenses.

The Commission finds and concludes that the operating ratio method is appropriate for water operations in this proceeding and that the rate base methodology is appropriate for sewer operations in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 3

The evidence for this finding of fact is contained in the Company's application and the testimony and exhibits of Public Staff witnesses Fernald and Brown.

The components of the Applicant's rate base as set forth by the Company and the Public Staff are shown below:

WATER OPERATIONS

	Per Application	Per Public Staff	Difference
Plant in service	$ 95,668	$ 95,668	$ 0
Accumulated depreciation	(19,135)	(22,962)	(3,827)
Net plant in service	76,533	72,706	(3,827)
Cash working capital	17,390	18,941	1,551
Average tax accruals	(1,017)	(1,066)	(49)
Customer deposits	0	(1,500)	(1,500)
Original cost rate base	$ 92,906	$ 89,081	$ (3,825)

SEWER OPERATIONS

	Per Application	Per Public Staff	Difference
Plant in service	$ 969,738	$ 872,645	$ (97,093)
Contributions in aid of construction	(216,000)	(216,000)	0
Accumulated depreciation	(91,295)	(20,416)	70,879
Excess capacity	0	(394,612)	(394,612)
Net plant in service	662,443	241,617	(420,826)
Cash working capital	11,800	12,014	214
Average tax accruals	(1,238)	(1,435)	(197)
Customer deposits	0	(1,550)	(1,550)
Original cost rate base	$ 673,005	$ 250,646	$(422,359)

The Company did not dispute the amounts presented by the Public Staff except for the following adjustments: removal of sewer connection to City of Sanford; adjustment for excess capacity for the wastewater treatment plant; and adjustment for excess capacity for the Carr Creek sewer lines.

(a) <u>Excess capacity for the sewer connection to the City of Sanford:</u> Before the new wastewater treatment plant was built, Carolina Trace contracted with the City of Sanford for wastewater treatment to supplement the capacity of the then existing 150,000 gallon per day plant. In order to utilize the City of Sanford's treatment capabilities, Carolina Trace had to build the interconnection and was required to pay a minimum monthly charge. The gross investment in the sewer interconnection with Sanford is $89,722. The minimum monthly payment to Sanford is $523.33. The new wastewater treatment plant was placed in service on December 7, 1989, and has a capacity of 325,000 gallons per day. Brinn Exhibit 1 shows that the Company continued to divert some sewage to Sanford for treatment in the first four months after the new treatment plant was operational. However, from April of 1990 through the close of hearing, Carolina Trace has treated all of its sewage at the new plant and none of it has been diverted through the connection to Sanford.

The Company's position is that the interconnection is required to meet peak flow requirements and as a backup in case of failure of the wastewater treatment plant. Mr. Brinn anticipated that the Company would use the connection with Sanford this coming winter when he expected either rainwater infiltration would increase the sewage flow or mechanical problems at the new plant could make it necessary to have a backup for treatment.

Company witness Brinn also testified that the connection with Sanford gave the Company more time before a future expansion for growth would be needed. He described the connection as: "It is really you are buying additional facilities that might be needed in the future when you reach plant capacity." This and other testimony of Mr. Brinn indicated that the connection to Sanford amounts to extra sewer capacity at a time when the design sewer needs of existing customers have not fully consumed the capacity on the Company's treatment plant. He stated that the design capacity of the treatment plant was 325,000 gallons per day.

Mr. Brinn also indicated that during the early operation of the new treatment plant, when some sewage was being diverted to Sanford, the treatment plant was not at full capacity. At that time, the treatment plant was experiencing start-up problems; those problems have been fixed and since then the Company has not had to divert sewage to Sanford. Mr. Brinn could not say to what extent the sewage diversion to Sanford was due to start-up problems at the new plant and to what extent it was due to rainwater infiltration.

Company witness Brinn admitted that the new treatment plant by itself -- without adding the amount of treatment capacity acquired through the connection with Sanford -- provided more capacity than needed to serve today's customers. He agreed that the Sanford connection was not reliable capacity because the City could terminate its contract at any time. Actually, the contract with Sanford, which appears as Late-filed Exhibit 2, not only gives Sanford broad discretion to refuse treatment of Carolina Trace's sewage, but it expired on June 30, 1988. It thus appears that the Company has no legal right to obtain sewage treatment from Sanford.

Public Staff witness Fernald excluded the cost of the sewer connection to Sanford from her rate base recommendation because "the Company no longer sends sewage to the City of Sanford" and therefore this plant is "no longer used and useful." Public Staff witness Brown testified:

> "I have recommended that the cost of the force main connection to the City of Sanford sewer system be eliminated from rate base and that the monthly minimum charge for wastewater treatment by the City of Sanford be eliminated from expenses. This is based on information from the Company that pumping to Sanford has ceased and also upon examination of the flow data. There is ample capacity in the plant to treat the additional flow to the plant during periods of higher infiltration, especially if the equalization chamber is correctly utilized."

On cross-examination, Mr. Brown agreed that there were certain hypothetical circumstances in which the possibility of needing the connection to Sanford could arise. On redirect, he clarified that the connection with Sanford was nonetheless not a necessary backup to the new treatment plant.

The Commission concludes that the cost of the connection to Sanford should not be included in plant in service. The new treatment plant was built with some additional capacity that is not required for today's customers, and it has an equalization chamber that should be capable of smoothing peak flows. The connection to Sanford has not been used since April of 1990. There is no contractual basis and no clear certainty that Sanford will accept wastewater from Carolina Trace for treatment in the future. It is not reasonable that the customers of Carolina Trace should pay higher rates for this interconnection just so their utility can have a backup system that other utilities are able to exist without. It is possible that the connection to Sanford will be useful to Carolina Trace in some future year as the subdivision grows and as the City of Sanford becomes more able to take outside wastewater, but for the present the interconnection between Sanford and Carolina Trace is not used and useful to the ratepayers.

There is no question, however, that the connection has been used and useful for utility service in the past. The connection was needed to supplement the capacity of the Company's then existing 150,000 gallons per day plant. The sewage for Carolina Trace could not have been treated in any other way. Although the Commission has found and concluded that the connection is no longer used and useful, the Commission is of the opinion that the connection should be treated as extraordinary property retirement and amortized over a six-year period, with the unamortized balance included in rate base. In this way the Company will be allowed to recover its investment in plant that at one time was used and useful to provide service.

(b) <u>Excess capacity at the new sewage treatment plant:</u> The Company requested that all the cost of the new treatment plant be included in rate base. The Public Staff recommended that 52%, or $228,292, of the new plant cost be disallowed from rate base as excess capacity.

Company witness Brinn testified that the new treatment plant had a capacity of 325,000 gallons per day and that under Division of Environmental Management (DEM) design criteria a capacity of 281,000 gallons per day would be required for the 781 end-of-period customers. The Company's position is that the required design capacity of the plant for end-of-period customers is at least 281,000 gallons per day because of the DEM design requirement of 120 gallons per day per bedroom. Company witness Brinn presented computations showing an average of 3 bedrooms per residence in Carolina Trace. The computations further showed that 781 residences x 3 bedrooms x 120 gallons = 281,160 gallons per day.

Company witness Brinn further testified that it was necessary to build the new wastewater plant since the Company needed more capacity and the City of Sanford was unwilling and unable--due to the limited capacity of its lines and lift stations--to handle increasing amounts of sewage from Carolina Trace. Mr. Brinn also testified that the Company, in reliance upon its engineer, submitted plans and specifications for the new plant to DEM based upon DEM design criteria of 120 gallons per day per bedroom for a residence. Although the 281,000 gallons represented design criteria, not actual flow, Mr. Brinn stated that there were some days when the actual flows were close to 281,000 gallons per day.

Public Staff witness Brown testified:

> "I have recommended that 48 percent of the cost of the new wastewater treatment plant be allowed in rate base, because only 48 percent of the design flow rate of the plant is utilized to serve the existing customers. This is based on the monthly average flow rate for the maximum month since the recording flowmeter was recalibrated at the end of May 1990. The existing customers should not be required to pay for plant that will be utilized by future customers."

Mr. Brown discussed how the DEM design requirement of 120 gallons per day per bedroom had an exception based on historical usage levels and how the DEM design standards were conservative requirements that accounted for infiltration during rainy periods and had a safety margin built into them. He determined that the maximum month's flow since the meter was correctly calibrated yielded an average of 155,000 gallons per day (gpd) against the rated capacity of 325,000 gpd, resulting in only 48% of the capacity being needed for current customers. He did not recommend any allowance for future growth.

The applicable DEM regulation (Section 219, sub-paragraph 1) reads as follows:

> "In determining the volume of sewage from dwelling units, the flow rate shall be 120 gallons per day per bedroom. The minimum volume of sewage from each dwelling unit shall be 240 gallons per day and each additional bedroom above two bedrooms will increase the volume by 120 gallons per day. Each bedroom or any other room or addition that can reasonably be expected to function as a bedroom shall be considered a bedroom for design purposes. When the occupancy of a dwelling unit exceeds two persons per bedroom, the volume of sewage shall be determined by the maximum occupancy at a rate of 60 gallons per person per day."

In Docket No. W-354, Subs 74, 79, and 81 (Carolina Water Service rate case, Order of June 15, 1990) the Commission found in Finding of Fact No. 11:

> "It is appropriate to utilize a standard of 400 gallons per day per connection in determining the design capacity of elevated storage tanks and sewer treatment plants."

The Commission on page 45 of the June 15, 1990 Order stated:

> "Public Staff witness Lee testified that although the correct design capacity for wastewater treatment plants is 400 gallons per day, the state allows reevaluation of design capacity based on historical usage data. The Public Staff employed such an historical usage figure, rather than a 400 gallons per day standard, in determining the capacity currently used in the Brandywine Bay sewage treatment plant."

The Commission further stated in its CWS Order on page 47:

> "If the Commission were to permit the adjustment advocated by the Public Staff, to be nondiscriminatory, it would have to reexamine on a regular basis every sewage facility in the state. The Commission would then have to analyze the change in flow to determine and apply a percent utilization. This process would be both impractical for the Commission and unfair to the utilities who constructed their facilities under a specific design standard. The Commission, therefore, rejects the Public Staff's reevaluation of the capacity using an historical usage figure." (emphasis added.)

The Commission concludes that the design capacity of the new wastewater treatment plant, of 120 gallons per day per bedroom resulting in 360 gallons per day per unit, is the correct criterion to determine the percent of utilization. The Company designed this sewer plant based on 360 gallons per day requirement included in the DEM minimum design criteria. The Public Staff's argument to use the historical usage figures from May, 1990 through the date of hearing in November, 1990, all of which occurred after the plant was constructed, is without merit. The Company has not applied for a plant capacity reduction through DEM and there is no evidence by the Public Staff that such a reduction would be granted by DEM. The Company in good faith relied on the State minimum design criteria.

The Commission concludes that the percentage utilization method advocated by the Public Staff is too rigid in that it is based upon the premise that a utility's investment in service capacity should be exactly equal to current customer demand. Such premise ignores any engineering, construction, and maintenance efficiencies which exist in designing and constructing sewer plant facilities to meet reasonable anticipated growth. It also ignores the design criteria for new plants established by DEM in its rules and regulations. DEM is given primary jurisdiction by the State to regulate the design, construction, and operation of wastewater treatment plants. The design criteria of this State agency should be accorded great weight by the Commission in determining the amount of plant to be included in rate base.

(c) Excess capacity on the Carr Creek sewer lines: Since the last rate case, sewer mains have been installed in the Carr Creek area at a cost of approximately $432,000. The Company has treated approximately one half of the cost as being recovered through lot sales. Only 93 of the 403 lots (or 23 per cent) were occupied as of August 31, 1990. The Public Staff recommended that only the unrecovered (50 per cent) portion of the sewer line costs relating to the 23 per cent of the lots that are occupied be included in rate base. Since 77 per cent of the lots to be served by the Carr Creek sewer lines are unoccupied, the Public

Staff recommended that none of the costs of 77 per cent of those lines be allowed in rate base -- resulting in a difference of $166,320 (total cost of $432,000 x 50 per cent contribution x 77 per cent excess capacity) between the Company and the Public Staff.

The Company maintained that some of the occupied lots are located at the end of each of the branches of the collection system and, therefore, the entire line is required to transport wastewater to the treatment plant.

The Hearing Examiner rejected the Company's argument and concluded that the Public Staff's adjustment was proper for two reasons. First, there is a failure of proof on the Company's part. Mr. Brinn admitted that he did not know how many of the Carr Creek sewer lines have houses at the ends of the lines. Therefore, no basis exists to determine how many of those lines are "used" for their entire length. Secondly, the collection system is designed for 403 connections and currently serves only 93 connections.

The Commission will now address the issue of the plant capacity allowance as provided for by the Hearing Examiner in his Recommended Order. The Hearing Examiner in reaching his decision in this regard found and concluded that a plant capacity allowance of 35 percent of that portion of the design capacity of the Company's new wastewater treatment plant not fully utilized in serving existing customers at the end of the test year and 35 percent of that portion of certain sewer lines not fully utilized in serving existing customers at the end of the test year were properly includable in determining the Company's cost of service for purposes of this proceeding. In recognition of the need for this allowance, the Hearing Examiner in essence concluded that it is unrealistic and unreasonable to expect that the plant capacity of a prudently managed public utility will always be exactly equal to that required in order to serve the demand for service from existing customers, and no more. In order for such an equality to exist, the utility would be required to routinely ignore economic efficiency, including optimal plant design. Such action would be totally inconsistent with the public interest and contrary to Commission policy.

Under the percentage utilization method employed by the Public Staff, the utility would unfairly experience economic loss as a result of it being denied the opportunity to recover a portion of its prudently invested capital through the inclusion of reasonable depreciation expense in its cost of service and as a result of it being denied the opportunity to earn a fair return on a portion of its unrecovered investment in public utility property that was used and useful in providing public utility services. These losses would hinder the utility's ability to attract capital on reasonable terms which ultimately would result in increased costs to consumers.

If there is a reasonable belief that customer demand will increase in the foreseeable future and if significant economies of scale in construction costs exist, cost savings can be attained by building or expanding to an optimum plant size. Such is the case with respect to the instant proceeding. The Commission agrees with the Hearing Examiner's conclusion that it is entirely inappropriate to arbitrarily assume that all plant capacity over and above that needed to provide service to existing customers is excessive and therefore is not used and useful in providing service at the end of the test year. However, the Commission believes that the proper allowance, based on the evidence in this case, for such required plant capacity is an amount equal to 14 percent of that portion of the subject plant facilities that are being fully utilized in providing service to existing customers as opposed to the allowance employed in the Recommended Order. This determination is based upon the Commission having concluded that in order to achieve economic efficiency certain plant facilities cannot be constructed on a piecemeal basis; that it is entirely appropriate and consistent with the public interest for the Company to maintain a reasonable level of reserve capacity; that a planning horizon of two years is appropriate for use in this proceeding for this purpose; that the annual growth in demand for water and sewer services in the Company's franchised service area is in the range of 7 percent; and that the inclusion of an allowance for such required plant capacity in determining the Company's cost of service or overall revenue requirement achieves the most propitious matching of revenues and costs from the standpoint of periodic income determination and public utility rate regulation.

The Company has a duty to meet increased demand and to anticipate the demand to be placed upon it in the foreseeable future. The North Carolina Supreme Court addressed this issue in State ex rel. Utilities Commission v. General Telephone Company of the Southeast, 281 N.C. 318, 189 S.E.2d 705 (1972):

> "...a public utility is under a present duty to anticipate, within reason, demands to be made upon it for service in the near future. (citations omitted) Substantial latitude must be allowed the directors of the utility in making the determination as to what plant is presently required to meet the service demand of the immediate future, since construction to meet such demand is time consuming and piecemeal construction programs are wasteful and not in the best interest of either the ratepayers or the stockholders."

This and other issues here under review were addressed more recently by the North Carolina Supreme Court in State ex rel. Utilities Commission v. Carolina Water Service, Inc. of North Carolina, 328 N.C. 299 (1991). With respect to the propriety of the Commission having included in current rates costs associated with plant capacity needed to serve future customer demand, the Supreme Court in this decision at page 307 stated as follows:

> "CWS, relying on Utilities Comm. v. Telephone Co., 281 N.C. 318, 189 S.E.2d 705, argues that the Commission is laboring under the false impression that current ratepayers cannot be required to pay through rates for plant that can be used for future growth. That is not how we read the order of the Commission. As we read the order, the Commission allowed for capacity larger than presently needed which could reasonably be foreseen to be needed in the near future."

Based on the foregoing and the entire evidence of record, the Commission finds and concludes that it is reasonable and proper in determining the Company's cost of service for purposes of this proceeding to include an allowance of $60,127 ($53,172 for the wastewater treatment plant and $6,955 for the Carr Creek sewer lines) for plant capacity above that marginally needed to serve existing customer demand. This plant capacity can reasonably be foreseen to be needed in the near future and is representative of the level of such capacity that the Company can reasonably be expected to maintain on an ongoing basis. Thus, the inclusion of this capacity is entirely consistent with the ratemaking process, including the requirement that there be a proper matching of revenues and costs. The plant capacity allowance for the new wastewater treatment plant of $432,967 is calculated as follows:

781 end-of-period Customers x 3.0 bedroom average x 120 gallons per day per bedroom = 281,160 gallons per day (gpd)

Total Plant Capacity	325,000 gpd
Less: Minimum Design Requirements	281,160 gpd
Reduction	43,840 gpd

281,160 gpd minimum design requirements x 14% percentage utilization reasonable capacity allowance = 39,362 gpd

Reduction	43,840 gpd
Less: Percentage utilization reasonable capacity allowance	39,362 gpd
Net Reduction	4,478 gpd

Total Plant Capacity		Net Reduction		Net Wastewater Plant in Service
325,000	Less	4,478	=	320,522 gpd

320,522 gpd divided by 325,000 Total Plant Capacity = 98.62% of Plant Utilized

Total Plant Cost		Percent of Plant Utilized		Plant Allowed In Rate Base
$439,024	x	98.62%	=	$432,967

The plant capacity allowance for the Carr Creek sewer lines of $56,635 is calculated as follows:

Item	Amount
Total original cost	$ 432,000
Less: Contribution in aid of construction	(216,000)
Net Investment	216,000
Cost of plant before reasonable capacity allowance ($49,680 x 23%)	49,680
Percentage utilization reasonable capacity allowance factor	14%
Percentage utilization reasonable capacity allowance ($49,680 x 14%)	6,955
Plant allowed in Rate Base ($49,680 + 6,955)	$ 56,635

Finally, with respect to the plant capacity allowance; as previously indicated the Commission has developed this allowance as a function of plant facilities that are being fully utilized in providing service to existing customers, as opposed to the methodology employed by the Hearing Examiner which essentially develops this allowance as a function of plant not fully utilized in serving existing customers. The Commission, after having carefully consider this matter, has determined that a much better correlation exists between fully utilized plant facilities and the subject allowance than exists between the subject allowance and plant facilities not fully utilized in providing service to existing customers when all of the parameters entering into the Commission's decision making process are properly considered and weighed. The Commission hastens to add, however, that no aspect of its decision reflected herein with respect to the issue of the proper plant capacity allowance for use in this proceeding should in any way be construed to constitute a precedent with respect to the treatment of such costs in past, present or future proceedings before this Commission. Matters such as this must be carefully considered on a case-by-case basis so that they may be properly addressed based upon their own unique set of circumstances and judged based upon their on merits.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding is contained in the Company's application, in the testimony and exhibits of Public Staff witnesses Fernald and Brown, and in the Public Staff Late-filed Exhibit.

The Public Staff's calculation, based on 842 water customers and 781 sewer customers, was not contested.

The Hearing Examiner, therefore, concludes that the appropriate level of operating revenues under present rates is $109,181 for water operations and $102,422 for sewer operations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding is contained in the Company's application, in the late-filed exhibits, and in the testimony and exhibits of Public Staff witnesses Fernald and Brown, Company witnesses Brinn and Perkerson, and customer witness Bishop.

Operating revenue deductions under present rates as presented by the Company and the Public Staff are shown below:

WATER OPERATIONS

	Per Application	Per Public Staff	Difference
Oper. & Maint. salaries	$ 12,007	$ 12,096	$ 89
Purchased power	3,998	4,428	430
Purchased water	80,021	95,937	15,916
Maintenance and repairs	7,680	7,647	(33)
Testing	2,916	646	(2,270)
Chemicals	1,029	897	(132)
Transportation	2,373	2,763	390
General salaries	11,192	14,749	3,557
Office expense	1,704	1,795	91
Rent	2,082	2,082	0
Insurance	5,200	966	(4,234)
Office utilities	1,951	2,226	275
Meter reading	650	650	0
Professional fees	4,200	2,500	(1,700)
Rate case expense	2,117	2,148	31
Total O&M expense	139,120	151,530	12,410
Depreciation expense	3,827	3,827	0
Taxes - payroll	2,099	1,946	(153)
Taxes - GRT & regulatory fee	3,885	4,498	613
State income tax	0	0	0
Federal income tax	0	0	0
Revenue deductions	$148,931	$161,801	$12,870

SEWER OPERATIONS

	Per Application	Per Public Staff	Difference
Oper. & Maint. salaries	$ 11,096	$ 11,166	$ 70
Purchased power	19,646	30,020	10,374
Purchased sewer	6,386	0	(6,386)
Maintenance and repairs	18,425	12,687	(5,738)
Testing	6,924	7,260	336
Chemicals	882	1,386	504
Transportation	2,193	2,554	361
General salaries	10,343	13,615	3,272
Office expense	1,574	1,647	73
Rent	1,924	1,924	0
Insurance	4,800	3,723	(1,077)
Office utilities	1,802	2,055	253
Meter reading	600	600	0
Professional fees	4,200	2,500	(1,700)
Rate case expense	2,000	2,140	140
Sludge removal	1,500	2,711	1,211
Interest on customer deposits	0	124	124
Total O&M expense	94,295	96,112	1,817
Depreciation expense	30,150	10,481	(19,669)
Taxes - payroll	1,940	1,798	(142)
Taxes - GRT & regulatory fee	5,385	6,268	883
State income tax	0	0	0
Federal income tax	0	0	0
Revenue deductions	$131,770	$114,659	$(17,111)

Mr. Bishop, a customer of the Company, proposed a number of adjustments during the hearing. Most of these adjustments are addressed in Evidence and Conclusions for Findings of Fact Nos. 9 and 13. One of Mr. Bishop's adjustments, which related to the purchased water expense, will be discussed here. Mr. Bishop proposed a disallowance, or adjustment, of $11,992 in purchased water expense to reflect that a 12.5 per cent loss of water in the system is more reasonable than the 25 per cent loss reflected by the Company in its application. In his testimony on further direct, Public Staff witness Brown agreed that there was a loss of approximately 25 per cent in the water that is purchased and pumped by the Company and which does not ultimately reach the customers. Mr. Brown further testified that the 25 per cent figure "may be on the high range." He further testified that, based on his conversations with municipal operators, 15 to 20 per cent would be considered a "good average" with respect to loss, and above 20 per cent would be "less than good."

The Commission is of the opinion that there is some merit in the adjustment proposed by Mr. Bishop with respect to the allowance for water loss, and will find and conclude that the disallowance for water loss should be based upon a 20 per cent loss factor. In so deciding, the Commission has taken into account that the water system in this proceeding, as compared to most municipal operations, is a small system and that the water facilities are not new.

The Company did not dispute the amounts presented by the Public Staff except for the following: (1) insurance expense, (2) depreciation expense, and (3) monthly payment to Sanford to keep open the contract for sewage treatment by Sanford.

The proper level of insurance expense was settled by the Public Staff and the Company after the hearing. Both parties changed their initial expense level to the amount that appears in the Public Staff column shown above. The Commission concludes that this is the proper level of insurance expense.

The difference in depreciation expense is solely due to the different amounts of rate base recommended by the parties. The Company contested the plant in service and excess capacity for sewer operations on which the Public Staff's depreciation expense was calculated. As discussed in Finding of Fact No. 3, the Commission has concluded that for sewer operations the plant in service is $872,645, the excess capacity is ($165,424) and that the Company should be allowed to amortize the unrecovered costs of the sewer connection with Sanford over a six year period, resulting in an annual amortization of $11,365. Therefore, the depreciation and amortization expense for sewer operations is $31,014.

The Public Staff and the Company disputed the reasonableness of the monthly payment of $523.33 to the City of Sanford to keep open the interconnection between the Company's collection system and the City's wastewater treatment facility. The arguments surrounding the reasonableness of this monthly expense are the same as the arguments related to whether the capital cost of the connection should be in plant in service. For the reasons stated in Finding of Fact No. 3, the Commission concludes that the connection with Sanford is not currently used and useful; therefore the monthly payment to maintain the availability of wastewater treatment through the connection is not a reasonable expense to charge to the ratepayers.

Based on the foregoing adjustments, the Commission concludes that the appropriate level of operating revenue deductions under present rates is $157,129 for water operations and $135,192 for sewer operations.

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

The evidence supporting these findings of fact is found in the Application for rate increase and in the affidavit, testimony, and exhibits of Public Staff witnesses Sessoms, Fernald, and Brown. These findings are uncontested and uncontroverted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Based upon the foregoing findings and conclusions, the Commission concludes that the Applicant should be allowed an increase in operating revenues of $73,679 for water operations and $109,538 for sewer operations in order to have the opportunity to achieve an 11.5% overall rate of return. The following schedules incorporate the findings and conclusions of the Commission:

NET ORIGINAL COST RATE BASE
For the Test Year Ended September 30, 1989

	Water Operations	Sewer Operations
Utility Plant in service	$ 95,668	$ 872,645
Less - Contributions in aid of construction	0	(216,000)
Accumulated depreciation	(22,962)	(30,974)
Excess capacity	0	(165,424)
Average tax accruals	(1,066)	(1,435)
Customer deposits	(1,500)	(1,550)
Plus - Cash working capital	18,941	12,014
Unamortized extraordinary property retirement	$ 0	$ 56,823
Total rate base	$ 89,081	$ 526,099

NET OPERATING INCOME FOR RETURN
For the Test Year Ended September 30, 1989

WATER OPERATIONS

Item	Present Rates	Increase Approved	After Approved Rates
Operating revenue	$109,181	$73,679	$182,860
Operating revenue deductions:			
O&M expenses	146,858	0	146,858
Depreciation expense	3,827	0	3,827
Taxes - payroll	1,946	0	1,946
Operating revenue deductions requiring a return	152,631	0	152,631
Taxes - GRT and regulatory fee	4,498	3,036	7,534
State income taxes	0	1,589	1,589
Federal income taxes	0	3,553	3,553
Total operating revenue deductions	157,129	8,178	165,307
Net operating income for return	$(47,948)	$65,501	$ 17,553
Margin on operating revenue deductions requiring a return			11.5%

NET OPERATING INCOME FOR RETURN
For the Test Year Ended September 30, 1989

SEWER OPERATIONS

Item	Present Rates	Increase Approved	After Approved Rates
Operating revenue	$102,422	$109,538	$211,960
Operating revenue deductions:			
O&M expenses	96,112	0	96,112
Depreciation & amortization	31,014	0	31,014
Taxes - payroll .	1,798	0	1,798
Taxes - GRT and regulatory fee	6,268	6,704	12,972
State income taxes	0	2,791	2,971
Federal income taxes	0	6,592	6,592
Total operating revenue deductions	135,192	16,267	151,459
Net operating income for return	$(32,770)	$93,271	$ 60,501
Net original cost rate base			526,099
Return on rate base			11.5%

The Schedule of Rates, attached to this order as Appendix A, will provide the Applicant with a reasonable opportunity to produce the allowed increase in revenues and is therefore just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

The evidence supporting this finding of fact is contained in the testimony of public witness William C. Bishop and Company witness Brinn.

Mr. Bishop, a resident of Carolina Trace, who appeared on behalf of the Carolina Trace Association, recommended that Carolina Trace Corporation be directed to account for tap-on fees in conformity with the Uniform System of Accounts for water and sewer companies published by the National Association of Regulatory Utilities Commissioners (NARUC) since this would provide for easier identification of cost versus reimbursement for tap-ons.

Rule R7-35 of the North Carolina Utilities Commission states:

> "The Uniform System of Accounts for Water Utilities as revised in 1973 by the National Association of Regulatory Utility Commissioners is hereby adopted as the accounting rules of this Commission for water companies and is prescribed for the use of all water utilities under the jurisdiction of the North Carolina Utilities Commission having annual gross operating revenues of $10,000 or more derived from the sales of water."

A similar provision exists for sewer utilities in Rule R10-21.

Mr. Brinn was unaware that the Company's books had not been maintained according to these Rules, but he agreed to comply with them in the future. The Commission concludes that the Applicant should account for tap-on fees and contributions in aid of construction in accordance with the Uniform System of Accounts for water and sewer companies published by NARUC.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is contained in the testimony of public witnesses Jenson, Louer, Clayton, Jarred, Voorhees, Gillis, Schuster, Heath, Fish, Goodwin, and Kratz, Public Staff witness Brown, and Company witness Brinn.

Ms. Jenson, Mr. Louer, Mr. Gillis, Ms. Schuster, Mr. Heath, Mr. Fish, and Mr. Kratz testified that they have experienced discolored water. Mr. Clayton, Mr. Jarred, and Ms. Schuster testified that they have installed filtration systems to improve their water. They indicated that the water quality was such that the filter elements required replacement more frequently than manufacturer's recommendations.

Other specific water quality concerns were expressed by several of the customers. Mr. Voorhees described a metallic taste in the water. Mr. Kratz and Mr. Fish indicated that the water frequently has an unpleasant odor. Mr. Fish also stated that there are occasions of excessive chlorine in the water.

Ms. Goodwin and Mr. Voorhees expressed concerns about water quality testing. A notice of a monitoring failure was presented.

Mr. Kratz and Ms. Goodwin testified that there had been occurrences of service interruptions without prior notice. Ms. Goodwin also testified that often there is a six month wait for road repairs after a service connection.

Mr. Louer testified that there were occasional sewer odors at the community swimming pool, and Mr. Heath described a history of the sewer system's manholes overflowing.

Public Staff witness Brown testified that the elevated storage tank should have an altimeter type control that prevents overfilling and overflowing of the tank. He also recommended that the Company undertake a scheduled program of flushing the distribution system, with notice to the customers of the flushing schedule, and a policy of isolating affected areas during repairs, and removal of unsightly PVC pipe risers.

The Commission concludes that the water utility service being provided by Carolina Trace is generally adequate. However, the testimony presented reveals that there are areas needing improvement. The Commission also concludes that the sewer service is adequate.

The Applicant should take the steps necessary to improve the quality of the water, including sufficiently flushing the system. The Applicant should also make the other improvements recommended by Public Staff witness Brown.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence for this finding of fact is contained in the Company's application and in the testimony of public witnesses Duensing, Jenson, Cary, Wolmering, Jarred, Gillis, Fish, Goodwin, and Kratz, and in the testimony of Public Staff witness Brown and Company witness Brinn.

The public witnesses were opposed to paying for wastewater treatment of water that did not enter the system (i.e., water used for irrigation, automobile washing, etc.). Two witnesses, Mr. Wolmering and Mr. Kratz, suggested that the cap should be reduced to a level lower than the current 6,000 gallons per month.

The Company proposed to remove the 6,000 gallon cap. The Public Staff recommended that it continue.

The Commission concludes that no new reason has been advanced to justify removal of a cap that was found reasonable in prior dockets for this Company. However, since no revenues are collected on gallons used above 6,000 gallons when a maximum cap is imposed, the sewer charge per gallon will therefore have to be higher on the usage below 6,000 gallons in order to recover the required revenue found proper by this Order. The Public Staff calculation of revenue in its late-filed Exhibit accounts for this rate design requirement, and the Commission's Order will so reflect.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is contained in the Applicant's Late Filed Exhibit 1. The exhibit provides a detailed breakdown of the costs involved in installing water and sewer taps. Based upon the reasonable expenses listed in the exhibit, the Commission concludes that the proper tap fee for water service is $605 plus full gross up. Likewise, the proper tap fee for sewer service is $533 plus full gross up.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

A number of adjustments were proposed by a customer knowledgeable in regulatory accounting and ratemaking, Mr. Bishop, on behalf of the Carolina Trace Association. They include:

(a) A proposed disallowance of $145,792 in the sewer rate base due to the failure of the Carolina Trace Corporation to fully account for contributions in aid of construction resulting from the sale of lots after September 30, 1982,

(b) A proposed disallowance in the water rate base for failure of Carolina Trace Corporation to fully account for contributions in aid of construction resulting from the sale of lots after September 30, 1982,

(c) Tap-fees to be set at $200 for water and $250 for sewer, so as to prevent the Company from overrecovering its investment, and

(d) A proposed disallowance (adjustment) of $11,992 in purchased water expense to reflect that a 12.5% loss of water in the system is more reasonable than the 25% loss that the Company wants customers to pay for.

The Commission has carefully considered these proposals in reaching his decision in this Order. The recommendation of Mr. Bishop that the Company follow accepted utility accounting practices with respect to tap fees, which was also recommended by the Public Staff, has been incorporated in this Order. His recommendation as to a proposed disallowance in the water rate base is rendered moot on the grounds that the Commission has employed the operating ratio method in setting rates for the water utility. With respect to the proposed disallowance of $145,792 in the sewer rate base due to the Company's failure to fully account for CIAC resulting from the sale of lots, the evidence disclosed that the Company included in sewer rate base only three non-contributed plant items: the connection to Sanford, one-half of the cost of sewage collection lines to the 403 lots in the Carr Creek Area, and the cost of the new wastewater treatment plant. All the remaining cost of the sewer system, including the collection lines for the remaining 2,000 lots, all force mains and lifts stations, and the entire cost of the original wastewater treatment plant, were treated as being 100% contributed by the development company. With respect to Mr. Bishop's proposal for tap fees of $200 for water and $250 for sewer, the Commission has found elsewhere that the tap fees allowed herein are just and reasonable. (See Finding of Fact No. 12, above.) With respect to Mr. Bishop's proposed adjustment in purchase water expense, the Commission has discussed and considered this matter elsewhere in this Order under Evidence and Conclusions for Finding of Fact No. 5.

IT IS, THEREFORE, ORDERED as follows:

1. That Carolina Trace Corporation be, and hereby is, allowed to increase its water utility rates to produce $73,679 additional gross revenues above that level in effect prior to interim rates approval, for service rendered on and after the date of this Order.

2. That Carolina Trace be, and hereby is, allowed to increase its sewer utility rates to produce $109,538 additional gross revenues above that level in effect prior to interim rates approval, for service rendered on and after the date of this Order.

3. That the Schedule of Rates attached to this Order as Appendix A is hereby approved as the just and reasonable rates for the Applicant and shall become effective for service rendered on and after the date of this Order. This Order constitutes compliance with G.S. 62-138.

4. That Carolina Trace shall take such actions to improve the water and sewer utility service as were addressed in the testimony of Public Staff witness Brown and discussed in the Evidence and Conclusions for Finding of Fact No. 10.

5. That Carolina Trace shall account for its utility operations, including tap fees and contributions in aid of construction, according to the Uniform System of Accounts for water and sewer utilities.

6. That the 6,000 gallon usage cap on the rate for sewer charges shall continue in effect.

7. That Carolina Trace Corporation shall deliver a copy of Appendix B, attached hereto, to each customer during the first billing cycle following the effective date of this Order.

8. That the exceptions filed by the Public Staff be, and the same are hereby, determined as set forth above in this Final Order on Exceptions Approving Rates.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of May 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A

SCHEDULE OF RATES
for
CAROLINA TRACE CORPORATION
for providing water and sewer utility service in
Carolina Trace Subdivision
in Lee County, North Carolina

Residential Metered Rates:

Water base charge (zero usage)	$7.35
Water usage charge	$2.05/1,000 gallons
Sewer base charge (zero usage)	$8.75
Sewer usage charge (maximum 6,000 gallons)	$3.45/1,000 gallons

Tap On Fee:

Water service connection	$605 plus full gross up
Sewer service connection	$533 plus full gross up

Reconnection Charge:

If water service cut off by utility for good cause:	$15.00
If water service discontinued at customer's request:	$15.00
If sewer service cut off by utility for good cause:	$15.00

Bills Due: On billing date

Bills Past Due: 15 days after billing date

Billing Frequency: Shall be monthly for service in arrears

Finance Charges for Late Payment: Shall be 1% per month on 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-436, Sub 4, on this the 31st day of May 1991.

APPENDIX B

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-436, SUB 4

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Carolina Trace Corporation, Post Office Box 2250, Sanford, North Carolina 27330, for Authority to Increase Rates for Providing Water and Sewer Utility Service in Carolina Trace Subdivision in Lee County, North Carolina	NOTICE TO CUSTOMERS OF NEW RATES

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to Carolina Trace Corporation, for water and sewer utility service provided in Carolina Trace Subdivision in Lee County, North Carolina. This decision was based upon evidence presented at the public hearing held on November 14, 1990, in Sanford, North Carolina.

The new rates supersede the interim rates and are as follows:

Residential Metered Rates:

Water base charge (zero usage)	$7.35
Water usage charge	$2.05/1,000 gallons
Sewer base charge (zero usage)	$8.75
Sewer usage charge (maximum 6,000 gallons)	$3.45/1,000 gallons

Tap On Fee:

Water service connection	$605 plus full gross up
Sewer service connection	$533 plus full gross up

Carolina Trace has been ordered to make a number of repairs and system improvements as recommended by the Public Staff, including a regularly scheduled water flushing program with notice to the customers of the times of flushing.

ISSUED BY ORDER OF THE COMMISSION.
This the 31st day of May 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

DOCKET NO. W-720, SUB 50

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by Mid South Water Systems, Inc., Post Office Box 127, Sherrills Ford, North Carolina, for a Certificate of Public Convenience and Necessity to Furnish Water and Sewer Utility Service in The Landings Subdivision in Catawba County, North Carolina, and for Approval of Rates	ORDER GRANTING MOTION FOR RECONSIDERATION AND REQUIRING PARTIAL REFUND

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Thursday, June 27, 1991, at 11 a.m.

BEFORE: Chairman William W. Redman, Jr., Presiding, and Commissioners Sarah Lindsay Tate, Robert O. Wells, Julius A. Wright, Charles H. Hughes, and Laurence A. Cobb

APPEARANCES:

For Mid South Water Systems, Inc.:

Sam H. Long, III, Attorney at Law, Long, Cloer & Elliott, Post Office Box 9547, Hickory, North Carolina 28803

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff-North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626

BY THE COMMISSION: On May 17, 1991, the Commission issued its Order Granting Franchise and Requiring Refunds in the above-captioned matter. Said Order required Mid South Water Systems, Inc. (Mid South), to refund to its customers in The Landings Condominiums the rates collected by it prior to May 17, 1991.

On June 17, 1991, Mid South filed its Motion for Reconsideration of Order Requiring Refunds.

By Order dated June 20, 1991, the Commission scheduled Mid South's motion for reconsideration for oral argument on June 27, 1991.

The matter subsequently came in for oral argument before the Full Commission at the scheduled place and time. Mid South, through its attorney, offered oral argument in support of its motion and the Public Staff responded.

In the oral argument, Mid South argued that at most it should be required to refund only the rates collected during the months of May, June, and July 1989. This, Mid South contended, was the length of time that the Public Staff normally requires to complete its application process once all of the necessary exhibits are filed. Mid South argued that it should be penalized for only its mistake; i.e. charging for rates in May, June, and July of 1989, and not for the mistake of the Public Staff; i.e. failing to present the application to the Commission once all exhibits were filed.

The Public Staff, as it did at the Staff Conference when this matter was first presented, did not take a position on refunds but indicated that the Commission's decision requiring refunds was justified by law.

Based on the entire record in this proceeding, the Commission is of the opinion that Mid South should be required to refund to its customers in The Landings Condominiums only the monies collected during the months of May, June, and July 1989. Through its written motion and oral argument by its counsel, Mid South has established good cause in support of its motion for reconsideration. That being the case, the Commission hereby modifies Mid South's refund responsibility in accordance with this Order on reconsideration.

IT IS, THEREFORE, ORDERED as follows:

1. That, beginning in the next billing cycle following the date of this Order, Mid South shall refund to its customers in The Landing Condominiums the rates collected by it during the months of May, June, and July 1989. The refund shall be made in equal monthly installments on customer bills over a three-month period or in a lump sum to any former customer who is no longer on the system.

2. That Mid South shall file a report on the status of these refunds no later than November 1, 1991.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
Gail L. Mount, Deputy Clerk

(SEAL)

DOCKET NO. W-778, SUB 9
DOCKET NO. W-778, SUB 10
DOCKET NO. W-778, SUB 11
DOCKET NO. W-778, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water Utility Service in Forest Hills Subdivision in Jackson County, North Carolina)
and

In the Matter of Application of CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Harbour Subdivision in Craven County, North Carolina and In the Matter of Application of CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Mountains Subdivision in Rutherford County, North Carolina and In the Matter of Application of CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Sapphire Valley Subdivision in Jackson and Transylvania Counties, North Carolina	ORDER GRANTING PARTIAL INCREASE IN RATES AND CHARGES

HEARD IN: The Hospitality Room, Room 1302, Ramsey Center, Western Carolina University, Cullowhee, North Carolina, on Wednesday, September 25, 1991.

Fairfield Harbour Community Center, New Bern, North Carolina, on Thursday, October 3, 1991.

Superior Courtroom, Second Floor, Courthouse, Broad Street, New Bern, North Carolina, on Thursday, October 3, 1991.

Superior Courtroom, Rutherford County Courthouse, Rutherfordton, North Carolina, on Thursday, September 26, 1991.

Conference Center, Fairfield Sapphire Valley Subdivision, Sapphire, North Carolina, on Thursday, September 26, 1991.

Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Wednesday, November 5, 1991.

BEFORE: Commissioner Robert O. Wells, Presiding, and Commissioners Laurence A. Cobb, and Charles H. Hughes

APPEARANCES:

For CWS Systems, Inc.:

Edward S. Finley, Jr., Hunton & Williams, Post Office Box 109, Raleigh, North Carolina 27602

For Townhouse Association E, Inc.; Fox Run Property Owners Association, Inc.; Maple Ridge Property Owners Association, Inc.; Mountain Loft Property Owners Association, Inc.; and Fairfield Mountains Property Owners Association, Inc.:

W. Daniel Martin, III, Ward and Smith P.A., 120 West Fire Tower Road, Post Office Box 8088, Greenville, North Carolina 27835-8088

For the Using and Consuming Public:

Robert B. Cauthen, Jr., Staff Attorney, and Paul L. Lassiter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520

BY THE COMMISSION: On May 31, 1991, CWS Systems, Inc. ("CWS" or "Company"), filed an application with the Commission in Docket No. W-778, Sub 9, seeking authority to increase rates for water utility service in Forest Hills Subdivision in Jackson County, North Carolina; and for water and sewer utility service in Fairfield Harbour Subdivision in Craven County, North Carolina; Fairfield Mountains Subdivision in Rutherford County, North Carolina; and Fairfield Sapphire Valley Subdivision in Jackson and Transylvania Counties, North Carolina.

On July 9 and 10, 1991, the Commission issued Orders assigning separate docket numbers as captioned, establishing general rate cases, suspending rates, granting interim rates in Docket Nos. W-778 Subs 9 and 11, denying interim rates in Docket Nos. W-778, Subs 10 and 12, scheduling hearings, and requiring public notice.

On October 25, 1991, Townhouse Association E, Inc.; Fox Run Property Owners Association, Inc.; Maple Ridge Property Owners Association, Inc.; Mountain Loft Property Owners Association, Inc.; and Fairfield Mountains Property Owners Association, Inc.; (all hereinafter collectively referred to as "Associations") filed its petition to intervene in this proceeding in regard to the Company's Fairfield Mountains Subdivision system. This motion to intervene was allowed by Commission Order issued on October 31, 1991.

On October 31, 1991, the Company filed a Motion requesting that the rates proposed by the Public Staff be granted as interim rates.

Public hearings were held as scheduled for the specific purpose of receiving testimony from public witnesses. The following public witnesses testified:

at Cullowhee (Forest Hills Subdivision)

Mr. Lee Budahl, Ms. Maxie Beaver, Mr. Daniel Perlmutter, Ms. Eileen Dillard, Ms. Bessie Powell, Mr. Gerald Almond, Jr., Ms. Teressa Sweeney, and Mr. Tom Massey;

at Sapphire Valley Conference Center (Sapphire Valley Subdivision)

Mr. Ralph Swingholm, Mr. John Fox, Mr. Dwight Carithers, Mr. Dave LaFontaine, Mr. Brian Renfro, Mr. Scott Rooth, Mr. Charles Putkovich, Mr. Mark Rogers, Mr. Jeff Joseph, Dr. Nicholas Chubb, and Mr. Aaron Barken;

at Rutherfordton (Fairfield Mountains Subdivision)

Mr. Richard Neher, Mr. Edward Finan, Mr. Richard Lorenzen, Mr. William Lowry, and Mr. Paul Nealon;

at Fairfield Harbor Community Center (Fairfield Harbor Subdivision)

Mr. Robert Leslie, Mr. George Giffin, Mr. Bob Doran, Mr. Bob Gruber, Mr. James Wood, Mr. Jim White, Mr. Morton Geller, and Mr. Robert Lauth; and

at Raleigh

Mr. George Giffin.

The case in chief came on for hearing as scheduled in Raleigh. The Company presented the testimony of Carl Daniel, Vice President and Regional Director of Operations of CWS, and Carl J. Wenz, Director of Regulatory Accounting for Utilities, Inc., and its subsidiaries, including CWS.

The Public Staff presented the testimony of Jan A. Larsen, Kenneth E. Rudder, and Ronald D. Brown, who are all Utilities Engineers with the Public Staff's Water Division, and Elise Cox, Assistant Director of the Public Staff's Accounting Division, who adopted the testimony of Linda P. Haywood.

On November 5, 1991, the Company and the Public Staff filed a joint stipulation resolving the matters in dispute between themselves and provided that the stipulated rates might be put into effect as interim rates pending a final order by the Commission.

On November 20, 1991, intervenor, "Associations", advised the Commission that no comments or other response to the Stipulation would be filed and a letter to this effect was filed on November 25, 1991. On November 21, 1991, the Commission issued an Order denying interim rates and requesting proposed orders from the Company and the Public Staff.

On November 26, 1991, the Company and the Public Staff filed a joint Motion and a Proposed Notice of Decision. In their Motion, the Company and the Public Staff advised the Commission that the granting of the stipulated rates had been an integral and essential element of their agreement. The Proposed Notice of Decision provided that the stipulated rates should go into effect immediately, that the stipulation should be adopted as a portion of the Commission's findings of fact, and that any remaining findings of fact, evidence and conclusions, and other matters should be contained in a final Order or Orders to be issued in due course.

Based upon the foregoing, the evidence adduced at the hearings and the entire record in this matter, the Commission makes the following:

FINDINGS OF FACT

1. CWS is a wholly owned subsidiary of Utilities Inc., and is duly franchised by this Commission to operate as a public utility in providing water and sewer service to customers residing in its various North Carolina service areas.

2. CWS is seeking an increase in its rates and charges for water utility service in Forest Hills Subdivision in Jackson County, North Carolina; and for water and sewer utility service in Fairfield Harbour Subdivision in Craven County, North Carolina; Fairfield Mountains Subdivision in Rutherford County, North Carolina; and Fairfield Sapphire Valley Subdivision in Jackson and Transylvania Counties, North Carolina.

3. The test period appropriate for use in this proceeding is the 12-month period ended March 31, 1991.

4. The Applicant, based on a test year ended March 31, 1991, has requested rates designed to produce additional gross annual service revenues as follows:

Docket	Revenue
W-778, Sub 9 (Water)	$ 15,217
W-778, Sub 10 (Water)	$ 64,026
W-778, Sub 10 (Sewer)	$ 93,317
W-778, Sub 11 (Water)	$119,583
W-778, Sub 11 (Sewer)	$ 41,633
W-778, Sub 12 (Water)	$183,923
W-778, Sub 12 (Sewer)	$138,835
TOTAL	$656,534

5. The Company is providing adequate water and sewer utility service in all the subdivisions included in this proceeding. However, the Commission is aware that there are on-going improvements in these systems and is monitoring the progress of these needed improvements by having required the Company in prior dockets to file quarterly progress reports in this regard.

6. The Company and the Public Staff filed a joint stipulation on November 5, 1991, resolving all matters in dispute between themselves. The only other intervening party, "Associations", filed a letter indicating that it had no comments on the joint stipulation. Only one public witness appeared after seeing the joint stipulation and he objected to the stipulated rates relating to Fairfield Harbour.

7. In its application, the Company requested the authority to impose a one-time assessment of $1,500 per single family equivalent in the Forest Hills

system to recover additional capital to be invested in Forest Hills improvements. In the joint stipulation, the Company withdrew this request.

8. The Company requested permission to accrue an Allowance for Funds Used During Construction (AFUDC) on each new capital project between its in-service date and the next subsequent general rate case. In the joint stipulation, the Company and the Public Staff agreed to defer a decision on the issue of accrual of AFUDC between the in-service date and incorporation into rate base until the next general rate case of Carolina Water Service, Inc. of North Carolina.

9. The Company and the Public Staff agreed in the joint stipulation that the reasonable original cost rate bases, used and useful in providing water and sewer utility service within the systems involved in this proceeding, are as follows:

Docket	Original Cost Rate Base
W-778, Sub 9 (Water)	$ 20,607
W-778, Sub 10 (Water)	$ 556,761
W-778, Sub 10 (Sewer)	$ 590,120
W-778, Sub 11 (Water)	$ 324,378
W-778, Sub 11 (Sewer)	$ 68,915
W-778, Sub 12 (Water)	$1,344,707
W-778, Sub 12 (Sewer)	$ 463,906

10. The Company and the Public Staff agreed in the joint stipulation that the appropriate level of gross service revenues for the test year under present rates, after end-of-period, accounting and pro forma adjustments, for the systems involved in this proceeding are as follows:

Docket	Service Revenue
W-778, Sub 9 (Water)	$ 27,355
W-778, Sub 10 (Water)	$189,690
W-778, Sub 10 (Sewer)	$229,625
W-778, Sub 11 (Water)	$150,726
W-778, Sub 11 (Sewer)	$ 89,929
W-778, Sub 12 (Water)	$195,721
W-778, Sub 12 (Sewer)	$138,003

11. The Company and the Public Staff agreed in the joint stipulation that the reasonable level of test year operating revenue deductions under present rates, after end-of-period, accounting and pro forma adjustments, for the various systems are as follows:

Docket	Operating Revenue Deductions
W-778, Sub 9 (Water)	$ 25,067
W-778, Sub 10 (Water)	$151,996
W-778, Sub 10 (Sewer)	$205,916
W-778, Sub 11 (Water)	$172,042
W-778, Sub 11 (Sewer)	$101,869
W-778, Sub 12 (Water)	$145,913
W-778, Sub 12 (Sewer)	$173,260

These levels of operating revenue deductions reflect the agreement that the amount budgeted for a cost of capital witness for CWS would be removed from rate case expenses.

12. The Company and the Public Staff agreed in the joint stipulation that a capital structure consisting of 56.50% long-term debt and 43.50% common equity is appropriate for use in this proceeding. Additionally, the Company and the Public Staff agreed that the appropriate embedded cost of long-term debt is 9.87% and that the appropriate return on common equity is 12.50%. Combining a return on common equity of 12.50% with the recommended capital structure and cost of long-term debt yields an overall return of 11.02% to be applied to the Company's original cost rate base to determine the revenue requirement for the following systems: (1) Fairfield Harbour water and sewer operations, (2) Fairfield Mountains water operation, and (3) Fairfield Sapphire Valley water and sewer operations.

13. The Company and the Public Staff agreed in the joint stipulation that the determination of the revenue requirement in the Forest Hills water operation and Fairfield Mountains sewer operation should be based upon the operating ratio methodolgy. For purposes of this proceeding, the Company and the Public Staff agreed that the appropriate margin on expenses requiring a return is 10.60%.

14. In order to provide the Company with the opportunity to earn the recommended returns, the Company and the Public Staff agreed in the joint stipulation that the appropriate gross revenue increases to be approved in the various systems are as follows:

Docket	Revenue
W-778, Sub 9 (Water)	$ 979
W-778, Sub 10 (Water)	$ 44,393
W-778, Sub 10 (Sewer)	$ 70,595
W-778, Sub 11 (Water)	$ 74,496
W-778, Sub 11 (Sewer)	$ 31,952
W-778, Sub 12 (Water)	$157,307
W-778, Sub 12 (Sewer)	$113,483
TOTAL	$493,205

15. The Company and the Public Staff stated that the joint stipulation filed in this proceeding resulted from extensive negotiations and compromise and therefore does not necessarily reflect the parties' beliefs as to the proper treatment or level of specific components. The parties agree that such components are reasonable only in the context of the overall settlement between the parties. The parties have agreed that none of the positions, treatments, figures, or other matters reflected in this joint stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters at issue. Based on this understanding, the Commission accepts the joint stipulation of the Company and the Public Staff.

16. In accordance with the recommended increases in revenues set forth in Finding of Fact No. 14, the Company should be allowed an increase in its annual gross service revenues for water utility service of $277,175 and for sewer utility service of $216,030. The rates, as agreed to by the Company and the

Public Staff and reflected in Appendices A-1 through A-4, will allow this increase, should enable the Company the opportunity to earn an 11.02% return on rate base or a 10.60% margin on operating expenses requiring a return, and are fair to the Company and its customers. Accordingly, the rates set forth in Appendices A-1 through A-4 are approved as the proper rates in this proceeding.

17. The interim rates which were placed into effect on July 10, 1991, in Forest Hills Subdivision are greater than the rates approved in this proceeding. Therefore the Company is required to refund, with 10% annual interest, the difference between the amount actually paid by each resident as interim rates and the amount which would have been due under the rates approved herein. The interim rates placed into effect on July 9, 1991, in the Fairfield Harbour Subdivision are just and reasonable and should no longer be subject to refund.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 1 THROUGH 4

The evidence supporting these findings of fact is contained in the verified application, the Commission's files and records regarding this proceeding, the Commission's Orders scheduling hearings, and the testimony of the Company and Public Staff witnesses. These findings are essentially informational, procedural, and jurisdictional in nature, and the matters which they involve are for the most part uncontroversial.

However, on the issue of the appropriate test year, questions over the appropriateness of using a test year ended March 31, 1991, were raised by some of the public witnesses. In particular, Lee Budahl, a customer in Forest Hills Subdivision, and Robert Leslie and George Giffin, customers in Fairfield Harbour Subdivision, recommended that the test year should have been for the 12 months ended December 31, 1991. Mr. Budahl expressed his concerns that the test year may not be an adequate choice of data in that it would only reflect CWS' operating data from December 1990 through March 1991 since December 1990 is when they acquired the Forest Hills system. Mr. Giffin stated "... that the test year be changed to the year ending December 31, 1991, on a basis that the test year as proposed by CWS Systems started even before they had signed a purchase contract with Fairfield Harbour or FCI and before they had made application for a transfer of the franchise and some 9 months before the Commission approved the transfer. And we feel to allow the utility to use that period when there was some question about the lawful operation of the things as the rate base is not proper." Mr. Leslie expressed the same concerns as Mr. Giffin.

The Commission has reviewed the evidence in this regard, including the transfer applications in Docket Nos. W-778, Subs 2 and 5. In Docket No. W-778, Sub 2, the Commission issued an Order on August 8, 1990, which allowed CWS temporary operating authority in the Fairfield Harbour Subdivision. This being the case, the Company had authority, granted by this Commission, to operate this system at least 8 months of the test year ended March 31, 1991. Additionally, in that docket it was also established that CWS had acted as operator of this system beginning April 4, 1990, which would have given them 12 months of operating experience in this system for the twelve months ended March 31, 1991.

In the Forest Hills' transfer application, Docket No. W-778, Sub 5, the Commission issued an Order on December 14, 1990, approving the transfer to CWS from the trustee in bankruptcy. Therefore, in the Forest Hills system the

Company's application for a rate increase reflected, for the most part, operating data for December 1990 through March 1991 which was annualized with some updating. For example, costs associated with plant additions expected to be in service by October 1991 were included, salaries and wage adjustments were adjusted to reflect wage rates at July 1, 1991, and transportation, office supplies, and other office expenses were adjusted to reflect additional costs associated with customer growth during the test year. In the prefiled testimony of the Public Staff, additional updating was proposed. For example, the levels of maintenance and repairs expense and electric power for pumping expenses were updated through the end of September 1991 and annualized.

Based on the foregoing, the Commission believes that the test year ended March 31, 1991, with subsequent updating through the close of the hearing, is not unreasonable for use in this proceeding. The historical operating data accumulated over the time period involved in these proceedings is a reasonable basis for making appropriate adjustments for the determination of the Company's representative on-going cost of service.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding comes from the testimony of Public Staff witnesses Larsen, Brown, and Rudder; the testimony of the public witnesses testifying at the different locations; and the testimony and rebuttal testimony of Company witness Daniel.

Witnesses Larsen, Brown, and Rudder stated that the systems were being operated properly and were being well maintained.

There were several witnesses testifying at the hearings in this matter; however, most testified of their concern of the magnitude of the rate increase. Only a few had complaints of service problems.

Company witness Daniel addressed each service problem testified to by the public witness. He indicated that the Company had corrected or was in the process of correcting all service related problems.

Based on the above, the Commission is of the opinion that the Applicant is providing adequate service in the four service areas involved in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 6 THROUGH 15

The evidence supporting these findings is contained in the November 5, 1991, joint stipulation entered into between the Company and the Public Staff, wherein all their differences were resolved, and in the testimony provided by the Company witnesses and the Public Staff witnesses at the hearing on this matter. The only other intervening party, "Associations", filed a letter indicating that it had no comments on the joint stipulation.

Only one public witness, George Giffin in Fairfield Harbour Subdivision, appeared after seeing the joint stipulation; he stated that the stipulated rates relating to Fairfield Harbour were still somewhat high. Mr. Giffin, generally objected to the use of a test year ended March 31, 1991, questioned the appropriateness of the level of rate base and recommended that a return of less than 10.00% on investment would be more appropriate than 11.10%. He admitted, however, that he did not have a total understanding of how such a return is determined. Additionally, Mr. Giffin stated "... I don't want to, at all, question the technical suitability of Utilities Incorporated or CWS Systems. I think they do a fine engineering job. Their on-site manager is very cooperative and gives us all the information we need. And I think they are fully qualified and really benefitting the user in what they're doing to our utility. But I believe, it's [sic] my duty as a representative of the property owners and the users of this community to drive for the lowest possible rates we can in this hearing...."

There were other public witnesses appearing in this proceeding who also questioned the level of rate base. In particular, Robert Leslie, a customer in Fairfield Harbour Subdivision, stated that he was concerned that the customers might have to pay again for the cost of the plant and asked the Public Staff and the Commission to make sure that the rights of the property owners are not sacrificed in the rate base determination.

The Public Staff, representing the using and consuming public, performed a full audit and investigation of the operations of the systems involved in these proceedings and prefiled testimony setting forth their specific recommendations on the appropriate cost of service for each of these operations and the proper level of rates. However, prior to the hearing in chief on these general rate cases, the Company and the Public Staff entered into a joint stipulation on all the differences between themselves. This joint stipulation resulted from extensive negotiations and compromise and, therefore, it does not necessarily reflect the parties' beliefs as to the proper treatment or level of specific components. The two parties agree that such components are reasonable only in the context of the overall settlement between the parties. The parties have agreed that none of the positions, treatments, figures, or other matters reflected in this joint stipulation shall have any precedential value nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters at issue.

In regard to questions raised by some of the public witnesses on the determination of rate base, the Commission believes a brief explanation is needed as to what was found on the determination of rate base in the Orders approving the transfers in each respective system.

In the transfer proceedings relating to the three Fairfield systems in Docket Nos. W-778, Subs 2, 3, and 4, an Order was issued on December 27, 1990, wherein the Commission approved the transfers and accepted the rate base jointly stipulated to by CWS and the Public Staff. The stipulation included the allocation of the $2.6 million purchase price to the respective systems acquired by CWS from Fairfield Communities, Inc. ("FCI"). The matters agreed to in that rate base stipulation were not controverted in the record. The rate base stipulation presented the Public Staff's calculation of net original cost to FCI and its affiliates as of April 4, 1990. In all three systems the Public Staff found that the level of net original cost rate base at April 4, 1990, was greater than the purchase price allocated to each of these systems.

In Docket No. W-778, Sub 5, relating to the transfer of the Forest Hills system, the Commission issued the Order approving the transfer on December 14, 1990, and found that the purchase price of $1,000 was the appropriate rate base since it was the same as the original cost net investment.

Based upon the record, the Commission finds no evidence indicating that the overall level of rate base agreed to by the parties is unreasonable or unfair. In this proceeding, it is the Commission's understanding that the various systems' rate bases were adjusted to incorporate the additional investments made by CWS since the transfer proceedings and only construction work in progress that had been completed prior to the close of the hearings was included. Additionally, there were adjustments made in accumulated depreciation/amortization, deferred charges, and working capital allowances.

Based upon the foregoing, the Commission accepts the joint stipulation of the Company and the Public Staff for purposes of this proceeding only. As stated by the Company and the Public Staff in the joint stipulation filed in this proceeding, the stipulation does not necessarily reflect the two parties' beliefs as to the proper treatment or level of specific components. The parties agree that such components are reasonable only in the context of the overall settlement between the parties. The parties have agreed, and the Commission concurs, that none of the positions, treatments, figures, or other matters reflected in this joint stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters at issue.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NOS. 16 AND 17

The evidence supporting these findings is contained in the November 5, 1991, joint stipulation entered into between the Company and the Public Staff wherein all their differences were resolved and in the testimony provided by the Company witnesses and the Public Staff witnesses at the hearing on this matter. The only other intervening party, "Associations", filed a letter indicating that it had no comments on the joint stipulation.

There were several public witnesses who testified at the hearings expressing their concerns in regard to the magnitude of the Company's proposed levels of rates. Some of these witnesses also expressed a desire to have a metered sewer rate rather than a flat rate.

The Company and the Public Staff agreed that a flat rate for residential customers was more appropriate because the majority of the expenses are fixed and are thus incurred regardless of the usage level of the consumer. The Commission agrees with the Company's and the Public Staff's recommendation in this regard.

Based upon the Commission's findings hereinabove concerning the Company's rate base, operating revenues, and operating revenue deductions, the Commission concludes that CWS should be allowed an annual increase in its water service revenues of $277,175 and its sewer service revenues of $216,030 in order to have the opportunity to earn an 11.02% return on rate base or a 10.60% margin on operating expenses requiring a return, which are fair and reasonable returns. Accordingly, the rates set forth in Appendices A-1 through A-4 are approved as the proper rates for use in this proceeding.

The interim rates which were placed into effect on July 10, 1991, in the Forest Hills Subdivision are greater than the rates approved in this proceeding. Therefore the Company is required to refund, with 10% annual interest, the difference between the amount actually paid by each resident as interim rates and the amount which would have been due under the rates approved herein. This refund may take the form of a credit on the next bill to these ratepayers. Within 30 days from the date of this Order, CWS should file an informational statement with the Commission indicating the calculated level of refunds and the manner in which they plan to make the refund.

The interim rates placed into effect on July 9, 1991, in the Fairfield Harbour Subdivision are just and reasonable and should no longer be subject to refund.

IT IS, THEREFORE, ORDERED, as follows:

1. That the Stipulation of CWS Systems, Inc., and the Public Staff, filed on November 5, 1991, is adopted by the Commission, with the understanding that none of the positions, treatments, figures, or other matters reflected in this joint stipulation shall have any precedential value, nor shall they otherwise be used in any subsequent proceedings before this Commission or any other regulatory body as proof of the matters at issue.

2. That CWS be, and hereby is, authorized to adjust its rates and charges to produce an annual increase in its water service revenues of $277,175 and its sewer service revenues of $216,030.

3. That the Company shall refund with interest to ratepayers in Forest Hills Subdivision the difference between the amount actually paid by each resident at interim rates and the amount which would have been due under the rates approved herein. This refund may take the form of a credit on the next bill to these ratepayers. Within 30 days from the date of this Order, CWS shall file an informational statement with the Commission indicating the calculated level of refunds and the manner in which they plan to make the refund.

4. That the interim rates approved for the Company in Fairfield Harbour Subdivision are just and reasonable and should be affirmed. The undertaking for refund filed by the Company in Docket No. W-778, Sub 11, is hereby discharged and canceled.

5. That the Schedules of Rates, attached hereto as Appendices A-1 through A-4, are approved for water and sewer utility service rendered by CWS and said rates and charges shall become effective for service rendered on or after the effective date of this Order.

6. That the Notices to Customers, attached hereto as Appendices B-1 through B-4, shall be served on the customers by inserting a copy of the

appropriate Appendix in the Company's next regularly scheduled billing statement following the effective date of this Order. A copy of the appropriate Appendix A shall also be attached to the Notice.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A-1

SCHEDULE OF RATES
for
CWS SYSTEMS, INC.
for providing water utility service in
FOREST HILLS SUBDIVISION
Jackson County, North Carolina

Residential Service:

Base Charge, zero usage	$7.00, minimum per month
Usage Charge	$2.05/1,000 gallons

Commercial Service:

Base Charge, zero usage per month (based upon meter size)

Meter Size	Base Charge
5/8 inch	$ 7.00
5/8 x 3/4 inch	$ 7.00
3/4 inch	$ 10.50
1 inch	$ 17.50
1 - 1/2 inch	$ 35.00
2 inch	$ 56.00
3 inch	$105.00
4 inch	$175.00
6 inch	$350.00

Usage Charge (All meter sizes): $2.05/1,000 gallons

Other Service:

Stand By Charge $5.00 per month

Connection Charge: New service only

5/8 inch meter $500.00

All other meter sizes: Actual cost of meter and installation

The connection charge is subject to the gross up multiplier provisions of the North Carolina Utilities Commission, Docket No. M-100, Sub 113.

New Water Customer Charge: $22.00

Reconnection Charge:
If water service is cut off by utility for good cause: $22.00
If water service is disconnected at the customer's request: $22.00

(Customers who request reconnection within nine months of disconnection will be charged the base charge for the number of months they were disconnected).

Bills Due: On billing date

Bills Past Due: 21 days after billing date

Finance Charge for Late Payment: 1% per month for balance due 25 days after billing date

Returned Check Charge: $10.00

Billing Frequency: Bills shall be rendered bi-monthly for service in arrears.

Issued in Accordance with Authority granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 9, on this the 10th day of December 1991.

APPENDIX B-1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 9

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois, 60062, for Authority to Increase Rates for Water Utility Service in Forest Hills Subdivision, Jackson County, North Carolina	)	NOTICE TO CUSTOMERS

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has issued an Order authorizing CWS Systems, Inc., to charge increased rates for water utility service. The new rates are as follows for residential customers:

Base Charge, zero usage	$7.00, minimum per month
Usage Charge	$2.05/1,000 gallons

The Commission issued its decision based upon evidence presented at public hearings which were held in Cullowhee and in Raleigh. CWS Systems, Inc., had also requested a plant modification fee or assessment of $1,500 per connection.

The utility has agreed to withdraw this request; therefore, there will be no assessment at this time. The refunds for interim rates in excess of the amount approved will be credited on a future bill.

ISSUED BY ORDER OF THE COMMISSION
This the 10 day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A-2

SCHEDULE OF RATES
for
CWS SYSTEMS, INC.
for providing water and sewer utility service in
FAIRFIELD HARBOUR DEVELOPMENT
Craven County, North Carolina
WATER RATE SCHEDULE

Residential:

(A) Base Facility Charge: $6.00 per dwelling unit. This $6.00 facility charge shall also apply where the service is provided through a master meter and each individual dwelling unit is being billed individually.

(B) Usage Charge: $1.59 per 1,000 gallons for all metered water usage.

Commercial and Other:	Base Charge, Zero Usage
5/8" x 3/4" meter	$6.00
3/4" meter	$9.00
1" meter	$15.00
1-1/2" meter	$30.00
2" meter	$48.00
3" meter	$90.00
4" meter	$150.00
6" meter	$300.00

Usage charge: $1.59/1,000 gallons

AVAILABILITY RATES: $2.00 monthly per customer

CONNECTION CHARGE: (Tap-on Fee)

All areas except Harbour Pointe II Subdivision:
$335.00 per tap (recoupment of capital)
$140.00 per tap (connection charge)

Harbour Pointe II Subdivision:
$650.00 per tap (recoupment of capital)
$320.00 per tap (connection charge)

The recoupment of the capital portion of the tap-on fees shall be due and payable at such time as the main water and sewer lines are installed in front on each lot within Harbour Pointe II and the connection charge for water and sewer shall be payable upon request by the owner of each such lot being connected to the water and sewer lines. With written consent of the Company, payment of the tap-on fee may be payable over a five year period following the installation of the water and sewer mains in front of each lot, payment to be made in such manner and in such installments as agreed upon between lot owner and the Company, together with interest on the balance of the unpaid tap fee from said time until payment in full at the rate of six percent per annum.

NEW CUSTOMER CHARGE: $22.00

RECONNECTION CHARGE:
If water service cut off by utility for good cause: $22.00
If water service discontinued at customer's request: $22.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base facility charge for the service period they were disconnected).

SEWER RATE SCHEDULE

Residential:
Flat rate per month per dwelling unit: $18.75

Dwelling unity shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor erecting the unit.

Commercial and Other:
(Customers who do not take water service will pay $18.75 per single family equivalent).

Base Charge, Zero Usage

5/8" x 3/4" meter	$6.00
3/4" meter	$9.00
1" meter	$15.00
1-1/2" meter	$30.00
2" meter	$48.00
3" meter	$90.00
4" meter	$150.00
6" meter	$300.00

Usage charge: $2.79/1,000 gallons

AVAILABILITY RATES: $2.00 monthly per customer

CONNECTION CHARGE: (Tap-on Fee)
All areas except Harbour Pointe II Subdivision:
$735.00 per tap (recoupment of capital)
$140.00 per tap (connection charge)

Harbour Pointe II Subdivision:
$2,215.00 per tap (recoupment of capital)
$310.00 per tap (connection charge)

The recoupment of the capital portion of the tap-on fees shall be due and payable at such time as the main water and sewer lines are installed in front on each lot within Harbour Pointe II and the connection charge for water and sewer shall be payable upon request by the owner of each such lot being connected to the water and sewer lines. With written consent of the Company, payment of the tap-on fee may be payable over a five year period following the installation of the water and sewer mains in front of each lot, payment to be made in such manner and in such installments as agreed upon between lot owner and the Company, together with interest on the balance of the unpaid tap fee from said time until payment in full at the rate of six percent per annum.

NEW CUSTOMER CHARGE: $16.50
(If customer also receives water service, this charge will be waived).

RECONNECTION CHARGE:

If water service cut off by utility for good cause, the actual cost of the disconnection and reconnection will be charged

The utility will itemize the estimated cost of disconnecting and reconnecting service and will furnish this estimate to customer with cut-off notice.

This charge will be waived if customer also receives water service for CWS Systems, Inc.

OTHER MATTERS

Bills Due: On billing date

Bills Past Due: 21 days after billing date

Billing Frequency: Shall be bi-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.

Return Check Charge: $7.00

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 10, on this the 10th day of December 1991.

APPENDIX B-2

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Harbour Development in Craven County, North Carolina	NOTICE TO CUSTOMERS

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to CWS Systems, Inc., for water and sewer utility service provided in Fairfield Harbour Development in Craven County, North Carolina. The rates are fully described in Appendix A, attached hereto.

This decision is based on evidence presented at public hearings held on October 3, 1991, in New Bern, North Carolina, and on November 5, 1991, in Raleigh, North Carolina.

ISSUED BY ORDER OF THE COMMISSION
This the 10th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
Geneva S. Thigpen, Chief Clerk

(SEAL)

APPENDIX A-3

SCHEDULE OF RATES
for
CWS SYSTEMS, INC.
for providing water and sewer utility service in
FAIRFIELD MOUNTAINS DEVELOPMENT
Rutherford County, North Carolina

METERED WATER RATE SCHEDULE

Residential:

(A) Base Facility Charge: $10.00 per dwelling unit. This $10.00 facility charge shall also apply where service is provided through a master meter and each individual dwelling unit is being billed individually.

(B) Commodity Charge: $3.67 per 1,000 gallons for all metered water usage.

Commercial and Other:

(A) Base Facility Charge:

5/8" x 3/4" meter	$ 10.00
3/4" meter	$ 15.00
1" meter	$ 25.00
1½" meter	$ 50.00
2" meter	$ 80.00
3" meter	$150.00
4" meter	$250.00
6" meter	$500.00

(B) Commodity Charge: $3.67 per 1000 gallons

CONNECTION CHARGE: (tap on fee) $500.00

NEW WATER CUSTOMER CHARGE: $22.00

RECONNECTION CHARGE:

If water service is cut off by utility for good cause: $22.00
If water service is discontinued at customer's request $22.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base facility for the service period they were disconnected)

SEWER RATE SCHEDULE

Residential:

Flat Rate per dwelling unit: $ 17.50

Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor erecting the unit.

Commercial and Other:

Based on water usage as follows: (subject to a minimum rate of $17.50/month. Customers who do not take water service will pay $17.50/single family equivalent).

(A) Base Facility Charge:

5/8" x 3/4" meter	$ 10.00
3/4" meter	$ 15.00
1" meter	$ 25.00
1½" meter	$ 50.00
2" meter	$ 80.00
3" meter	$150.00
4" meter	$250.00
6" meter	$500.00

(B) Commodity Charge: $6.32 per 1,000 gallons

CONNECTION CHARGE:(tap on fee) $550.00

NEW SEWER CUSTOMER CHARGE: $16.50
(If customer also receives water service, this charge will be waived).

RECONNECTION CHARGE:

If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will utilize the estimated cost of disconnecting and reconnecting service and will furnish this estimate to customers with cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

OTHER MATTERS

BILLS DUE:	On billing date
BILLS PAST DUE:	21 days after billing date
BILLING FREQUENCY:	Shall be bi-monthly for service in arrears
RETURNED CHECK CHARGE:	$7.00

FINANCE CHARGES FOR LATE PAYMENT:
1% per month for balance due 25 days after billing date

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 11, on this the 10th day of December 1991.

APPENDIX B-3

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 11

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Mountains Subdivision in Rutherford County, North Carolina	)	NOTICE TO CUSTOMERS

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to CWS Systems, Inc., for water and sewer utility service provided in Fairfield Mountains Subdivision in Rutherford County, North Carolina. The rates are fully described in Appendix A, attached hereto.

This decision is based on evidence presented at public hearings held on September 26, 1991, in Rutherfordton, North Carolina, and on November 5, 1991, in Raleigh, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

APPENDIX A-4

SCHEDULE OF RATES
for
CWS SYSTEMS, INC.
for providing water and sewer utility service in
SAPPHIRE VALLEY SUBDIVISION
Jackson and Transylvania Counties, North Carolina
METERED WATER RATE SCHEDULE

Residential:
(A) Base Facility Charge: $9.30 per dwelling unit. This $9.30 facility charge shall also apply where service is provided through a master meter and each individual dwelling unit is being billed individually.
(B) Commodity Charge: $4.05 per 1,000 gallons for all metered water usage.

Commercial and Other:

(A) Base Facility Charge:

5/8" x 3/4" meter	$ 9.30
3/4" meter	$ 13.95
1" meter	$ 23.25
1½" meter	$ 46.50
2" meter	$ 74.40
3" meter	$139.50
4" meter	$232.50
6" meter	$465.00

(B) Commodity Charge: $4.05 per 1,000 gallons

Availability: $5.00

CONNECTION CHARGE: (tap on fee) $400.00

METER INSTALLATION CHARGE: $150.00 (new service only)

NEW WATER CUSTOMER CHARGE: $22.00

RECONNECTION CHARGE:

If water service is cut off by utility for good cause: $22.00
If water service is discontinued at customer's request: $22.00

(Customers who ask to be reconnected within nine months of disconnection will be charged the base facility for the service period they were disconnected)

SEWER RATE SCHEDULE

Residential:

Flat Rate per dwelling unit: $ 27.30

Dwelling unit shall exclude any unit which has not been sold, rented, or otherwise conveyed by the developer or contractor erecting the unit.

Commercial and Other:

Based on water usage as follows: (subject to a minimum rate of $27.30/month. Customers who do not take water service will pay $27.30/single family equivalent).

(A) Base Facility Charge:

5/8" x 3/4" meter	$ 9.30
3/4" meter	$ 13.95
1" meter	$ 23.25
1½" meter	$ 46.50
2" meter	$ 74.40
3" meter	$139.50
4" meter	$232.50
6" meter	$465.00

(B) Commodity Charge: $5.79 per 1,000 gallons

Availability: $7.50

WATER AND SEWER - RATES

CONNECTION CHARGE: (tap on fee) $550.00

NEW SEWER CUSTOMER CHARGE: $16.50
(If customer also receives water service, this charge will be waived).

RECONNECTION CHARGE:
If sewer service is cut off by utility for good cause, the actual cost of disconnection and reconnection will be charged.

The utility will utilize the estimated cost of disconnecting and reconnecting service and will furnish this estimate to customers with cut-off notice.

This charge will be waived if customer also receives water service from CWS Systems, Inc.

OTHER MATTERS

BILLS DUE: On billing date

BILLS PAST DUE: 21 days after billing date

BILLING FREQUENCY:
Metered billing shall be bi-monthly for service in arrears
Availability billing shall be semi-annually in advance

RETURNED CHECK CHARGE: $7.00

FINANCE CHARGES FOR LATE PAYMENT:

1% per month for balance due 25 days after billing date

Issued in Accordance with Authority Granted by the North Carolina Utilities Commission in Docket No. W-778, Sub 12, on this the 10th day of December 1991.

APPENDIX B-4

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. W-778, SUB 12

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Application by CWS Systems, Inc., 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Increase Rates for Water and Sewer Utility Service in Fairfield Sapphire Valley Subdivision in Jackson and Transylvania Counties, North Carolina	NOTICE TO CUSTOMERS

BY THE COMMISSION: Notice is hereby given that the North Carolina Utilities Commission has granted a rate increase to CWS Systems, Inc., for water and sewer utility service provided in Fairfield Sapphire Valley Subdivision in Jackson and Transylvania Counties, North Carolina. The rates are fully described in Appendix A, attached hereto.

This decision is based on evidence presented at public hearings held on September 26, 1991, at Fairfield Sapphire Valley Subdivision, near Cashiers, North Carolina, and on November 5, 1991, in Raleigh, North Carolina.

ISSUED BY ORDER OF THE COMMISSION.
This the 10th day of December 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. W-798, SUB 3

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Petition of Bald Head Island Utilities, Inc., for Recovery of Capital Cost Investment in Utility Improvements and Fire Protection Facilities	)	ORDER DENYING ASSESSMENT AND APPROVING INCREASED TAP-ON FEE

HEARD IN: Bald Head Island Village Chapel, North Bald Head Wynd, Bald Head Island, North Carolina, on Thursday, March 14, 1991, at 7:00 p.m.

BEFORE: Commissioner Charles H. Hughes, Presiding; Chairman William W. Redman; and Commissioner Laurence A. Cobb

APPEARANCES:

For Bald Head Island Utilities, Inc:

Robert F. Page, Attorney at Law, Crisp, Davis, Schwentker, Page & Currin, Post Office Drawer 30489, Raleigh, North Carolina 27622

For the Public Staff:

Paul L. Lassiter, Staff Attorney, Public Staff - North Carolina Utilities Commission, Post Office Box 29520, Raleigh, North Carolina 27626-0520
For: The Using and Consuming Public

For the North Carolina Department of Justice:

Lorinzo L. Joyner, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27602
For: The Using and Consuming Public

BY THE COMMISSION: On December 14, 1990, Bald Head Island Utilities, Inc. (Applicant, Company, or BHIU), filed a petition to charge an assessment to its present customers and to increase the connection charge to recover certain costs of upgrading its water utility system. According to the Applicant, these upgrades would improve both the overall quality of the existing water system and make it compatible with the fire protection system to be constructed and owned by the Village of Bald Head Island (Village).

The Applicant stated that the existing water system was not planned to provide fire protection service. The Applicant indicated that the Village desires an adequate fire protection system constructed in the near future and has tentatively agreed to enter into a joint venture, along with the Property Owners Association (POA), to perform the necessary utility system upgrade and construct a fire protection system. The Applicant estimated that the total cost of all improvements and construction would be approximately $1,200,000. The Village and POA are to provide one half of this amount. The Applicant and the developer will provide the remaining half.

The Applicant stated in its original petition that it would be willing to proceed with upgrading the distribution system if it were allowed to recover its expenses over a five to six year period. In order to recover its costs within six years, the Applicant requested approval of the following:

1. A one-time assessment of $750 from each of its existing customers (approximately 350).

2. An increase in its connection charge from $1,000 to $1,750 (to be charged to all future customers).

On December 21, 1990, the Commission issued an Order requiring that Public Notice be given to all existing customers and property owners of the Applicant's proposed one-time assessment and increase in its connection charge. The Order provided that the Commission would not hold a hearing unless significant protest were received by January 18, 1991.

On January 25, 1991, the Public Staff and the Attorney General filed Motions with the Commission requesting the Commission to schedule a hearing in this matter. The Public Staff in its Motion indicated that it had received several phone calls and at least 14 protest letters opposing the Company's petition.

On February 1, 1991, the Commission issued an Order scheduling a public hearing on Thursday night, March 14, 1991, at the Bald Head Island Village Chapel on Bald Head Island, and requiring the Applicant to give public notice to its customers of this hearing.

The public hearing was held as scheduled at the Bald Head Island Village Chapel on Bald Head Island on Thursday night, March 14, 1991.

The Applicant presented the following witnesses: Michael Kent Mitchell, President of BHIU; William S. Riddick, Jr., a Registered Professional Engineer with the firm of McKim & Creed Engineers; David Edwards, Manager of BHIU; and Dave Busfield, Treasurer of BHIU.

The following customers testified: Jack Newton, Gene Fuss, Bill LeCates, Dr. Joseph Hooper, Mildred Strickland, and Harold Cunningham.

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

FINDINGS OF FACT

1. BHIU is duly franchised by this Commission to operate as a public utility in providing water and sewer service to customers residing on Bald Head Island.

2. The present water utility distribution facilities serving Bald Head Island serve 324 customers and consist of three separate water systems: (1) the Marina system; (2) the Central system; and (3) the Royal James system.

3. Approximately 64 lots/houses on Bald Head Island are served by private wells and, therefore, do not receive water utility service from Bald Head Island Utilities.

4. On the whole, the quality of water utility service now being provided by the Applicant is generally adequate. Several customers, however, complained of experiencing low pressure during peak summer periods and discolored and bad smelling water. The system upgrades for fire protection will have the side benefit of helping to alleviate these problems.

5. While the system is adequately configured to provide potable drinking water, it is inadequately sized and configured to allow for the installation of fire hydrants and the offering of fire protection.

6. BHIU is in the process of upgrading the water system so that it can offer fire protection. The improvements to the system include the physical interconnection of the three water systems, increasing the size of the mains, a 400,000 gallon ground water storage tank, special pumps, and installing more than 60 fire hydrants.

7. The cost of the improvements to the system will be around $1,200,000. The Village and the POA have agreed to pay for approximately one-half of the cost of upgrading the system for fire protection. The Village is planning to recover its cost for the installation of the fire protection system by a special tax assessment on all property owners.

8. In order to recover its portion of the cost of the improvements, BHIU is requesting Commission approval to increase its existing tap-on fee of $1,000 per connection to a new level of $1,750 per connection and to impose a one-time assessment or surcharge of $750 on each existing customer. These increases are designed to allow BHIU to recoup from its customers the cost of the improvements over a five to ten-year period.

9. BHIU is borrowing the money for its share of the cost of the improvements from Bald Head Island, Limited, the developer.

10. Homes on Bald Head Island now have a rating of ten (the highest risk level) for homeowners insurance. While it is likely that the installation of the fire protection system will reduce that rating and result in lower homeowners insurance premiums, insufficient evidence was presented as to the actual amount of such a reduction.

11. It is reasonable and appropriate for Bald Head Island Utilities to increase the tap fee to future customers by $750.00 to recover the cost of the existing utility system excluding any capital costs for improvements to provide fire protection.

12. It is not reasonable or appropriate to allow Bald Head Island Utilities to levy an assessment on present customers for the cost of the improvements necessary to provide a fire protection system or to recover the cost of the existing system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 1

The evidence supporting this finding of fact is contained in the Company's verified petition, the Commission's files and records regarding this proceeding, and the testimony of the witnesses.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 2 AND 3

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Mitchell and Riddick.

Mr. Mitchell stated that there are 324 customers being served water utility service by the Applicant. He testified, however, that not all residents are being served water by the utility as there are 64 private wells.

Company witnesses Mitchell and Riddick testified that the present water distribution facilities serving Bald Head Island consist of three separate systems which were developed independently of each other: (1) the Marina system; (2) the Central system; and (3) the Royal James system. These systems function independently and are not interconnected.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence supporting this finding of fact is contained in the testimony of the Company's witnesses and in the testimony of the public witnesses.

The Company witnesses testified that the existing three separate water systems installed on Bald Head Island are approved by the State as to design and ability to provide potable water. Company witness Riddick testified that a side benefit of upgrading and interconnecting the three separate systems to provide fire protection would be to increase the level of pressure and increase the quality of the water. Witness Riddick testified that the existing systems experienced low pressure problems during periods of peak summer demand, and that the new system with its 400,000 gallon per day storage tank would essentially provide a three-day storage supply of water, even during summer peak demands. Witness Riddick also testified that the additional storage would allow the Company to operate the existing wells at a more consistent rate, thereby preventing over-pumping, which has in the past resulted in diminished water quality from the wells. Witness Riddick also testified that the current treatment facilities for removal of hardness and iron would remain in place as currently installed on the wells; however, he stated that improved disinfection treatment (chlorination) equipment would be added at the central storage and distribution pumping location, which should also improve the quality of water. Witness Riddick testified that the system upgrades provide for a collection system to convey water from the wells to the storage tank and pumping station where the water will enter the distribution system.

Company witness Edwards testified that looping the new distribution system with additional new storage will allow the utility company to flush the lines better than is presently possible with the three separate systems.

Several of the witnesses testified as to quality problems with the water. The biggest complaint was with low water pressure. Other problems cited were that the water had a yellowish hue and a terrible odor to it.

Despite the problems, the Commission finds and concludes that the general quality of the water is adequate. In this regard, the Commission notes that the Company's witnesses testified that treatment equipment to remove hardness and iron is currently installed and operational at the existing wells. The complaint of discolored water and smelly water is a common problem where dead-end lines occur, and when combined with low customer usage and lack of flushing, can result in discolored and smelly water. The Commission requests that the Company investigate the water quality problems testified to by public witnesses Fuss and Hooper.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5 AND 6

The evidence supporting these findings of fact is contained in the Company's verified petition and in the testimony of the Company witnesses.

Company witness Riddick testified that the Company is in the process of upgrading the existing water distribution system to provide for fire protection. Larger mains are being installed to accommodate fire protection flow. The three existing water systems are being tied together so fire protection will be available to all areas within Phase 1 of the island. A 400,000 gallon ground storage tank and ancillary pumping facilities are being installed to provide an adequate source of water storage and pumping capacity for fire protection flow. Sixty fire hydrants will be placed throughout the system.

Witness Mitchell testified that the fire protection system requires substantially larger mains than those required for potable water needs. He stated that approximately one-half of the major mains would have to be increased in size from six-inches up to around 10 or 12-inches to accommodate the water flows for fire protection. He stated that the water flows required for potable water are a lot less stringent.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence supporting this finding of fact is contained in the Company's verified petition and in the testimony of the Company's witnesses.

Company witness Mitchell stated that BHIU had entered into lengthy negotiations with the Village and with the POA to work out an agreement to share the cost of upgrading the system to provide fire protection. The agreement that was worked out provides for the Village to pay for approximately one-half the cost. The Village will own the tank, fire pumps, the building for the pumps, and the Company will own all the distribution mains and well fields.

Company witness Mitchell stated that the exact cost of the improvements is not yet known as the Company still has a few items to resolve. He stated, however, that cost will end up being approximately $1,200,000 with the Village paying approximately $600,000 of this cost.

Company witness Mitchell testified that the Village is going to seek to recover its cost of the system through a tax assessment on all lot holders within the district. Mr. Mitchell stated that the final amount of the assessment had not yet been determined but that it would probably be around $600.00.

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

The evidence for these findings of fact is contained in the Company's verified petition and in the testimony of the Company witnesses.

By its petition, the Company is requesting Commission approval to increase its existing tap-on fee of $1,000 per connection to a new level of $1,750 per connection and to impose a one-time assessment or surcharge of $750 on each existing customer.

Company witness Mitchell stated that the Company was proposing a $750.00 assessment on water customers and to raise tap fees by $750.00. He stated that the Company had also considered charging customers a monthly surcharge but had dropped that idea before filing its application. The $750 assessment on present customers, along with the increase in tap fees and a monthly surcharge, was designed to recover the cost of the fire protection system in approximately five years. Witness Mitchell testified that the Company had decided not to charge a monthly surcharge for the improvements; therefore, it would take the Company in excess of five years to recover its costs. He estimated that the recovery period would be between five and ten years.

Company witness Mitchell stressed that the purpose of the assessment was to allow the Company to recover its costs over a relatively short period of time. Witness Mitchell did not give any theoretical justification for choosing five years except to say that this was the period found acceptable by the Company.

Based on the evidence in the record, the Commission finds and concludes that the proposed increase in tap fees and the proposed $750 assessment on current customers are designed to allow the Company to recoup from customers the cost of the improvements over a five to ten year period.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding of fact is found in the Company's verified petition and in the testimony of the witnesses at the hearing.

Company witness Mitchell testified that the homes on Bald Head Island have a fire/homeowners insurance rating of ten (the most risky). One of the reasons for this high rating is that the island does not have a fire protection system installed. Another reason is that the island has a volunteer rather than a full time fire department.

Witness Mitchell stated that it was his belief that the fire/homeowners insurance rating on Bald head Island will decrease to an eight (less risky than the present rating of ten) due to the installation of the fire protection system. He stated that water supply, pressure, and quality of storage were major components in the rating system. It was his opinion, therefore, that the rating would decrease and that homeowners insurance premiums would decrease. He estimated that premiums might decrease by fifteen percent which would result in a payback of the proposed assessment over several years.

Mr. Mitchell could not, however, verify the accuracy of his numbers as to the savings in homeowners insurance premiums to be derived by the installation of the fire protection system. He stated that the savings might be around fifteen percent, but he did not have any hard and fast numbers.

The Company did not tender an insurance expert to detail to the Commission the actual savings that would occur. The Commission, therefore, is at a loss to determine how much savings will actually occur and what will be the actual payback period for most homeowners.

Given the evidence, the Commission finds and concludes that the present homeowners insurance rating for Bald Head Island is ten and that such rating is likely to decrease with the installation of the fire protection system. The Commission must conclude, however, that there was insufficient evidence presented to determine the actual amount of the decrease.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is contained in the testimony of the Company's witnesses and the public witnesses.

BHIU requested that it be allowed to increase its existing tap-on fee from $1,000 to $1,750 to recover the increased cost of fire protection. According to Company witness Mitchell, it would be proper even without the improvements for fire protection to increase the tap-on fee to $1,750. He testified that the $1,000 tap-on fee was set based on the Company's 1983-84 cost and that $1,750 was more in line with current costs.

Based on witness Mitchell's testimony, the Commission will allow BHIU to increase its tap-on fee to $1,750 to recover the cost of its existing system excluding any capital costs incurred to provide fire protection. The Commission concludes that the record in this proceeding is inadequate to determine whether all or any portion of the costs which will be incurred by BHIU to provide fire protection may be included in the Company's cost of service. The Attorney General asserts that the Utilities Commission is without statutory authority to fix and require utility customers, over their objection, to pay utility rates designed to recover an investment made to provide fire protection, a nonutility service. The appropriate ratemaking treatment of the capital costs in question can best be examined and litigated in the context of a general rate case. For that reason, the Commission concludes that a decision on the ratemaking treatment of the expenditures for fire protection will be deferred until the Company's next general rate case.

Based upon the foregoing, the Commission finds and concludes that it is appropriate to increase the tap-on fee for new connections to $1,750 effective with the date of this Order in order to allow the Company to recover the cost of its existing system.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The evidence for this finding of fact is found in the testimony of the Company's witnesses and of the public witnesses at the hearing.

The Company's request for approval to charge existing water customers an assessment to recoup capital invested to upgrade the water utility system for fire protection is unusual. Normally a utility company is required to invest its own capital to make such improvements and then seek to recover a return on its investment through rates charged to customers and/or to recover its cost through tap-on fees charged to new customers as they connect to the system. The Commission normally has not allowed existing customers to be assessed for capital improvements except in emergency situations most often when an emergency operator has been appointed to operate the system. To allow collection of the assessment from current customers would be inconsistent wih our decision, set forth in conjunction with Finding of Fact No. 11, to defer a ruling on whether the cost of providing fire protection may be recovered from utility customers. It would also be unreasonable and inappropriate to assess current customers to recover the cost of the existing system for the following reasons.

BHIU has not represented that an emergency exists which would necessitate the need to appoint an emergency operator. The two major components of an emergency are (1) that water service is in imperilled and (2) that the utility is financially unable to obtain capital to maintain the system and/or to make needed improvements. In this case, the evidence is that the service presently being provided by BHIU is adequate and is not in any danger of being terminated. In addition, the testimony shows that Bald Head Island Utilities has been able to secure a loan from the developer for the improvements. On both counts, the evidence is clear that an emergency situation does not exist which would justify the Commission to approve an assessment.

The Commission views the imposition of an assessment as an extraordinary remedy which should be reserved for extraordinary circumstances. Be that as it may, the Commission might be inclined to approve an assessment if there were overwhelming customer support for such assessment. In the present case, however, there was not overwhelming support for the assessment. In fact, every single customer who testified at the hearing was opposed to the assessment. Moreover, nobody from the Village or POA appeared and testified in favor of the assessment.

BHIU stated in its petition filed on December 14, 1990, that the fire protection issue had been discussed at great lengths by both the POA and the Village and also at public hearings conducted by the Village. BHIU implied that there had been no substantial opposition to the proposal. This allegation was not borne out at the public hearing. In addition, the evidence indicated that BHIU had not made an adequate effort to try and meet with its customers at informal public meetings to explain the need for the improvements and work out a mutually agreeable way of raising the money for the improvements. Where a utility is seeking an extraordinary remedy, the Commission believes that it is incumbent on the utility to get out to the public and try and sell its plan to the customers. A utility just can't sit back and expect the Commission to foist a heroic remedy on an unsuspecting public.

The Company argued that the cost of the assessment will be recovered by the customers over a period of years through a reduction in the homeowners insurance premiums that each customer will pay. The Company, however, did not present hard and fast figures as to the actual savings that would occur (see Evidence and Conclusions for Finding of Fact No. 10). The Commission, therefore, has insufficient basis for finding that such savings would economically justify the assessment.

The Commission notes that there is an inequity built into the Company's assessment plan--that is, a number of individuals have their own wells and thereby will not be subject to the assessment. These individuals, however, will benefit from the fire protection system. Customers of the system, therefore, will be forced to pay costs that will benefit others.

After considering all factors, the Commission finds and concludes that it is inappropriate to impose an assessment on current ratepayers for the cost of the improvements necessary to provide fire protection or to recover the cost of the existing system which provides no fire protection.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's proposal to charge a one-time assessment of $750 on current customers be denied.

2. That the Company be authorized to increase its tap fee for new connections from $1,000 to $1,750 to recover the cost of the existing system excluding any capital costs incurred to provide fire protection.

3. That the Company shall give appropriate notice of the Commission's Order in this docket by mailing a notice to each of its customers during the next normal billing cycle. The Company shall submit the proposed customer notice to the Commission for approval prior to the notice being mailed out.

ISSUED BY ORDER OF THE COMMISSION.
This the 13th day of June 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

DOCKET NO. W-354, SUB 106

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of		
Application by Carolina Water Service, Inc., of North Carolina, 2335 Sanders Road, Northbrook, Illinois 60062, for Authority to Transfer the Franchise to Provide Water Utility Service in Grandview Subdivision in Forsyth County, North Carolina, from T-Square Water Company, Inc., and for Approval of Rates	)	ORDER GRANTING PRELIMINARY INJUNCTIVE RELIEF

HEARD IN: Commission Hearing Room, Dobbs Building, 430 North Salisbury Street, Raleigh, North Carolina, on Monday, July 8, 1991, at 2:00 p.m.

BEFORE: Commissioner Sarah Lindsay Tate, Presiding; Chairman William W. Redman, Jr., and Commissioners Julius A. Wright, Robert O. Wells, Charles H. Hughes, Laurence A. Cobb, and Allyson K. Duncan

APPEARANCES:

For Carolina Water Service, Inc., of North Carolina:

Edward S. Finley, Jr., and James L. Hunt, Hunton & Williams, Attorneys at Law, One Hannover Square, Suite 1400, Post Office Box 109, Raleigh, North Carolina 27602

For Lochurst Limited Partnership:

Theodore C. Brown, Jr., Attorney at Law, 1042 Washington Street, Raleigh, North Carolina 27605

BY THE COMMISSION: On June 17, 1991, Carolina Water Service, Inc., of North Carolina ("CWSNC" or "CWS") filed a request for preliminary and permanent injunctive relief against Lochurst Limited Partnership (Lochurst) and the City of Winston-Salem. In its request, CWSNC alleged that Lochurst and the City of Winston-Salem were planning to undertake certain action which would interfere with the franchise of CWSNC to provide public utility water service within its service areas of Lochurst and Grandview Subdivisions in Forsyth County. Attached to the request was the verification of James Camaren, Vice President, Business Development, of CWS. The request alleged a dispute between CWS and Lochurst of the right to provide water service in Lochurst Subdivision and the threat of Lochurst to obtain water from the City of Winston-Salem through an interconnection between the existing mains within Lochurst and the City water system; and that the City would provide service to Lochurst through the mains which CWS is presently using to provide water service within its franchise area.CWSNC further alleged certain facts supporting its rights of ownership and control of the mains and other facilities used by it to provide water service in the subject service area.

On June 20, 1991, the Commission issued an Order scheduling the request of CWS for hearing on Monday, July 8, 1991, at 2:00 p.m. The Order and the request

On June 20, 1991, the Commission issued an Order scheduling the request of CWS for hearing on Monday, July 8, 1991, at 2:00 p.m. The Order and the request of CWS were served by consent upon the attorneys for Lochurst and the City of Winston-Salem by U.S. Certified Mail.

On June 25, 1991, the City of Winston-Salem, by and through its Office of the City Attorney, filed a letter with the Commission setting forth the position of the Winston-Salem/Forsyth County Utility Commission with respect to the provision of water service to the Lochurst development. The City stated in its letter: "As the Commission has not taken, and has no plans to take, the action sought to be enjoined, I do not believe there is any basis for injunctive relief against the Winston-Salem/Forsyth County Utility Commission. Additionally, there are certainly jurisdictional questions surrounding the pending application."

On July 2, 1991, the Commission issued an Order accepting the letter of the City as the City's statement of position in this docket and excusing the City from further involvement in this proceeding. Attached to the Order, which was served upon all parties, was the letter of the City filed on June 25, 1991.

On July 8, 1991, the matter came on for oral argument upon affidavits before the full Commission. CWS and Lochurst Limited were present and represented by counsel. Both parties submitted affidavits and briefs in support of their positions in this docket. In addition, Lochurst Limited filed a Motion requesting that the Commission

> "1. Redefine the Service area of T-Square Water Co., Inc., which was sold to Carolina Water Service, Inc., in Docket No. W-354, Sub 91.
>
> "2. Specifically find that all deeds to mains and any laterals that are in the Lockhurst Subdivision have never been transferred to Carolina Water Service, Inc. by deed or any other means and therefore are the property of Lockhurst Limited Partnership."

On July 19, 199, CWSNC filed additional documents in this docket, including a title insurance policy insuring the "estate or interest in the land" described in a deed from T-Square Water Company to CWSNC dated March 14, 1990, and recorded the same day in the Forsyth County Registry.

Upon consideration of the verified request, the affidavits, briefs, and responses of the parties, the oral argument of counsel on July 8, 1991, and the judicial notice of Docket No. W-354, Sub 91, the Commission issues this Order granting preliminary injunctive relief against Lochurst Limited as hereinafter set forth. In support of the issuance of this Order, the Commission gives the following reasons: CWSNC seeks to enjoin Lochurst from interfering with the providing of water service in the CWS franchised areas in Lochurst and Grandview Subdivisions. (As discussed above, the Commission has dismissed the City of Winston-Salem from further involvement in this proceeding as a result of its letter of June 25, 1991.) In Docket No. W-354, Sub 91, the Commission by Order of January 14, 1991, granted to CWSNC a certificate of public convenience and necessity to provide water service in Grandview Subdivision. (CWSNC asserts that this granting of franchise also includes the Lochurst development.) The certificate gives CWS the exclusive right to provide public utility water service in the service area and imposes upon the Company the obligation to provide adequate water service to all customers in the service area in compliance with the laws of North Carolina and the rules and regulations of this Commission and the Division of Environmental Health, which administers the North Carolina Drinking Water Act. CWS alleged upon verified request and affidavit that there is a dispute between Lochurst and CWS, wherein Lochurst asserts that it owns the mains presently being used by CWS to provide water service in the Lochurst and Grandview Subdivision and that Lochurst is seeking a supply of water to the Lochurst development from the City of Winston-Salem through the mains now being used by CWS to fulfill its franchise obligations. CWS set forth several legal and equitable grounds upon which it bases its rights to the ownership and exclusive control of these disputed mains.

In its Application and Response, Lochurst admits that "there is a dispute as to the ownership of certain water mains within the Lochurst Subdivision, installed by [Lochurst] upon lands owned by [Lochurst] and never transferred or conveyed by Lochurst Limited to CWSNC, T-Square Water Company or any other entity." Lochurst further alleges that

> "the petitioner and respondent have agreed on nothing. Efforts are ongoing to try to obtain water for this subdivision, including extending City water to the entrance of the subdivision, but no agreement has yet been reached as regards <u>disconnecting CWSNC or transfer of water mains within the said subdivision."</u> (emphasis added.)

Lochurst further asserts that the Commission does not have jurisdiction over it or the City of Winston-Salem.

A preliminary injunction may be granted upon a showing by the petitioner that there is a likelihood of success on the merits of its case and that it is likely to suffer irreparable loss or harm unless the injunction is issued. <u>Ridge Community Investors, Inc.</u>, v. <u>Berry</u>, 293 N.C. 668, 701 (1977).

The Commission is of the opinion, and so concludes, that CWS has satisfied the requirements for the issuance of a preliminary injunction against Lochurst in this proceeding, pending the resolution of all matters in dispute between the two parties. Clearly, the interference with, or the frustration of, the ability of CWSNC to provide water service to its customers in its franchise service area would result in irreparable harm to the Company and to its customers, for whom there is no alternative source of water. The Commission is satisfied that the City of Winston-Salem will undertake no action that would threaten the service obligation of CWS; however, the Commission has not received sufficient assurance from Lochurst that it would refrain from any action, pending the resolution of the disputed issues, that would interfere with or frustrate the franchise obligation of CWS to adequately serve its customers. The supply of adequate public utility water service directly affects the health, safety, and welfare of the water customers and is consequently a matter of the highest concern to this Commission. See G.S. 62-116 and G.S. 62-118(b), which authorize the Commission to act in an emergency affecting a water system ("emergency" is defined as the imminent or actual loss of adequate water service). See also G.S. 62-310(b) which authorizes the Commission to seek injunctive relief in Superior Court against the unlawful provision of water utility service in violation of G.S. Chapter 62 or any rule, regulation, or order of the Commission.

The oral argument and affidavits likewise establish that there is a dispute between CWSNC and Lochurst as to the ownership of certain mains in the Lochurst development. The resolution of this issue appears to be a matter for the civil courts of the State and not for this Commission. Whether or not CWS will prevail in another forum cannot be conclusively determined by this Commission, nor does the applicable law require that the Commission do so. The Commission is satisfied, however, that CWS has presented legal and equitable grounds that may in good faith be asserted by the Company, with a likelihood of success, in any civil proceeding regarding its claim of ownership or right of exclusive control over the disputed mains.

In its motion of July 8, 1991, Lochurst has asked the Commission to "[r]edefine the service area of T-Square Water Co., Inc., which was sold to Carolina Water Service, Inc., in Docket No. W-354, Sub 91." CWSNC has not responded to this motion and will be afforded an opportunity to do so. Having issued this Order granting CWSNC relief in the nature of a preliminary injunction, the Commission must next decide the course of further proceedings in this docket. As discussed above, the Commission is of the opinion that this dispute over the ownership of the mains cannot be decided by this Commission. This Commission may, however, for good cause shown and after notice and hearing, define the franchise granted to CWSNC on January 14, 1991, and the rights and obligations of the Company thereof. Whether the issue of ownership, or the extent of the franchise, should be first resolved will be addressed by the parties in a subsequent filing, as requested by Ordering Paragraph 2.

In the meantime, the preliminary injunction granted by this Order will ensure that the customers of CWSNC in the affected service area will continue to receive an adequate supply of water pending the resolution of the issues between the parties.

IT IS, THEREFORE, ORDERED as follows:

1. That pending hearing and determination of the matters in dispute between CWSNC and Lochurst, Ltd., Lochurst, Ltd., and its officers, agents, servants, employees, and attorneys are hereby restrained and enjoined from interfering with, or diverting, disrupting, or terminating, or causing to be interfered with or diverted, disrupted or terminated, the supply and distribution of adequate public utility water service by CWSNC through the disputed mains to its customers in the Grandview and Lochurst Subdivisions, Forsyth County.

2. That within 20 days after the date of this Order, CWSNC shall be allowed to respond to the motion of Lochurst filed July 8, 1991. Further, within 20 days after the date of this Order, CWSNC and Lochurst, Ltd., shall file responses in this docket recommending the course of further proceedings in this docket.

ISSUED BY ORDER OF THE COMMISSION.
This the 23rd day of July 1991.

NORTH CAROLINA UTILITIES COMMISSION
(SEAL) Geneva S. Thigpen, Chief Clerk

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Carolina Power & Light Company - Order Approving Conveyance of Land and Requiring Deferred Accounting
E-2, Sub 333; E-2, Sub 537 (5-23-91)

Carolina Power & Light Company - Order Denying Increase in Connect and Reconnect Charges
E-2, Sub 600 (4-3-91)

Duke Power Company - Order Approving Rate Schedules and Customer Notice
E-7, Sub 487 (11-14-91)

Nantahala Power and Light Company - Order Approving Refund Plan
E-13, Sub 44 (2-7-91)

New River Light and Power Company - Order Approving Rate Adjustments and Requiring Notice
E-34, Sub 29 (7-17-91)

North Carolina Power - Order Approving Refund Plan with Modification
E-22, sub 314 (3-7-91)

North Carolina Power - Order on Motion for Clarification
E-22, Sub 314 (4-12-91)

North Carolina Power - Order Approving Rider D and Tariff Filings
E-22, Sub 314 (6-11-91)

North Carolina Power - Order Allowing Further Exception
E-22, Sub 324 (11-18-91)

SALES AND TRANSFER

Catalyst Energy Corporation of Montgomery County - Order Transferring Certificate No. SP-84 from Montgomery Hydro Power
SP-84 (7-1-91)

Cogentrix of North Carolina, Inc. - Order Approving Transfers Authorizing the West Point Pepperell Projects in Lumberton and Elizabethtown, and the Guilford Mills, Inc., Project in Kenansville
SP-16; SP-16, Sub 2; SP-16, Sub 4; SP-93 (12-19-91)

Milshoals Hydro Company, Inc. - Order Transferring Certificates of High Shoals Hydro, Inc., and Long Shoals, Hydro, Inc.
SP-83 (3-14-91)

Panda Energy Corporation - Order Transferring Certificate for Construction of a Cogeneration Facility to be Located Near the North West Corner of 13th Street and Roanoke Avenue, Roanoke Rapids, to Panda-Rosemary Corporation
SP-73, Sub 2 (6-3-91)

Worthville Hydro - Order Transferring Certificate to H. Bruce Cox (Cox Hydro Electric) of Certificate of Public Convenience and Necessity
SP-34; SP-80 (2-20-91)

SECURITIES

Carolina Power & Light Company - Order Granting Authority to Issue and Sell Additional Securities (Long-Term Debt)
E-2, Sub 593 (1-17-91)

Carolina Power & Light Company - Order Granting Authority to Consolidate Stock Purchase Plans and Issue Additional Stock Pursuant to Such Consolidated Plan
E-2, Sub 594 (1-25-91)

Carolina Power & Light Company - Order Granting Authority to Issue and Sell Additional Securities (Long-term Debt and Common Stock)
E-2, Sub 607 (11-8-91)

Carolina Power & Light Company - Order Granting Authority to Amend and Restate $72,500,000 Revolving Credit Agreement
E-2, Sub 609 (10-29-91)

Carolina Power & Light Company - Order Granting Authority to Amend $125,000,000 Amended and Restated Revolving Credit Agreement
E-2, Sub 613 (12-23-91)

Duke Power Company - Order Approving Issuance and Sell of Securities (Preferred Stock)
E-7, Sub 493 (6-6-91)

Nantahala Power and Light Company - Order Granting Authority to Issue Notes
E-13, Sub 150 (2-7-91)

TARIFFS

Carolina Power & Light Company - Order Approving Request to Discontinue Its Comparative Billing Program
E-2, Sub 454; E-2, Sub 458 (7-18-91)

Carolina Power & Light Company - Order Approving Rider and Amending Reporting Requirements for Approval of Dispatched Power Rider No. 688
E-2, Sub 567 (8-21-91)

Carolina Power & Light Company - Order Approving Rate Schedules
E-2, Sub 603 (10-15-91)

Carolina Power & Light Company - Order Suspending Proposed Rate Schedule
E-2, Sub 606 (8-7-91)

Carolina Power & Light Company - Order Approving Revised Rate Schedule
E-2, Sub 606 (9-17-91)

Duke Power Company - Order Approving Revisions Without Prejudice to Revise Its Non-Residential Air Conditioning Load Control and High Efficiency Ground Coupled Heat Pump Pilot Programs
E-7, Sub 469; E-100, Sub 58 (7-17-91)

Duke Power Company - Order Approving Rider LDCD(NC) Limited Demand Charge Day Service (Pilot)
E-7, Sub 487 (7-30-91)

MISCELLANEOUS

Carolina Power & Light Company - Order Approving Enhancements Without Prejudice
E-2, Sub 435 (5-22-91)

Carolina Power & Light Company and LaGrange Water Works Corporation - Order Approving Application for Transfer of Street Lighting Service in All of LaGrange's Service Areas, Cumberland County, to Carolina Power & Light
E-2, Sub 591 (1-16-91)

Carolina Power & Light Company - Order Approving Application for Billing Arrangements
E-2, Sub 604 (7-2-91)

Duke Power Company - Order Approving Expansion without Prejudice.
E-7, Sub 470 (6-11-91)

Duke Power Company -- Order Approving Agreement for Residential Load Control Service
E-7, Sub 477 (1-29-91)

Duke Power Company - Order Granting Interim Approval of Revised Residential Credit Code Classifications
E-7, Sub 482 (3-22-91)

Duke Power Company - Order Allowing Requested Accounting Treatment
E-7, Sub 484 (3-6-91)

Edgecombe-Martin County Electric Membership Corporation - Order Accepting Report of Construction and Granting Exemption
SP-88 (10-11-91)

Nantahala Power and Light Company - Order Approving Reassignment of Service Areas
ES-104 (3-13-91)

North Carolina Power - Order Approving Agreement
E-22, Sub 314 (7-8-91)

North Carolina Power - Order Approving Thermal and Equipment Standards for the Energy Saver Home
E-22, Sub 323 (2-14-91)

North Carolina Power - Order Granting Waiver
E-22, Sub 327 (7-29-91)

Robeson County - Order Accepting Report of Construction and Granting Exemption
SP-90 (11-20-91)

Rutherford Electric Membership Corporation - Order Accepting Report of Construction and Granting Exemption
SP-87 (10-11-91)

University of North Carolina at Chapel Hill - Order Granting Exemption from the Certificate Requirement of G.S. 62-110.1 Pursuant to G.S. 62-110.1(g)
SP-81 (3-8-91)

Western Carolina University - Order Approving Refund Proposal of Over-Collections Plus Interest to its Retail Customers
E-35, Sub 16 (3-20-91)

FERRY BOATS

CANCELLATIONS

Marshall, Conly - Order Cancelling Certificate for Certificate No. A-33
A-33, Sub 1 (5-21-91)

COMMON CARRIER

Barrier Island Transportation Service, Inc. - Order Granting Common Carrier Authority to Transport Passengers and Their Personal Effects from Calico Jack's Marina on Harker's Island to Cape Lookout Bright Area on Cape Lookout and Return
A-37 (6-17-91)

GAS

APPLICATIONS WITHDRAWN OR DISMISSED

North Carolina Natural Gas Corporation and Sonat, Inc. - Order Allowing Withdrawal of Application for Authority to Merge and Closing Docket
G-21, Sub 291 (9-17-91)

COMPLAINTS

Piedmont Natural Gas Company, Inc. - Recommended Order Granting Complaint of Hatteras Yachts, Inc.
G-9, Sub 302 (3-28-91)

Piedmont Natural Gas Company, Inc. - Order Denying Motion to Dismiss and Scheduling Hearing on Complaint of Howard L. Martin
G-9, Sub 307 (4-10-91)

Piedmont Natural Gas Company, Inc. - Order Providing Notice and Opportunity to Be Heard in Complaint of Henry H. Orr
G-9, Sub 315 (7-25-91)

Piedmont Natural Gas Company, Inc. - Order Closing Docket in Complaint of Henry H. Orr
G-9, Sub 315 (9-6-91)

Public Service Company of North Carolina, Inc. - Order Closing Docket in Complaint of Concord Farms
G-5, Sub 249 (9-13-91)

Public Service Company of North Carolina, Inc. - Recommended Order Denying Complaint of Eaton Corporation
G-5, Sub 270 (4-5-91)

Public Service Company of North Carolina, Inc. - Order Allowing Withdrawal of Complaint and Closing Docket in Complaint of Gaylord Container Corporation
G-5, Sub 274 (4-30-91)

Public Service Company of North Carolina, Inc. - Order Closing Docket in Complaint of Gerber Products Company
G-5, Sub 275 (4-4-91)

Public Service Company of North Carolina, Inc. - Order Accepting Settlement and Closing Docket in Complaint of Rodger Moore and Sharon Moore
G-5, Sub 282 (3-28-91)

Public Service Company of North Carolina, Inc. - Order Dismissing Complaint of Eaton Corporation
G-5, Sub 286 (11-21-91)

Public Service Company of North Carolina, Inc. - Order Dismissing Complaint of Gerber Products Company
G-5, Sub 287 (11-21-91)

EXPLORATION AND DEVELOPMENT - Order Approving E and D Refund Plan

Company	Docket Number	Date
Pennsylvania and Southern Gas Company	G-3, Sub 168	3-12-91
Piedmont Natural Gas Company, Inc.	G-9, Sub 312	3-27-91
Public Service Company of North Carolina, Inc.	G-5, Sub 281	3-27-91

RATES - PURCHASED GAS ADJUSTMENT (PGA)

North Carolina Natural Gas Corporation - Order Approving Filing and Requiring True-up Accounting Entry
G-21, Sub 281 (7-10-91)

North Carolina Natural Gas Corporation - Order on True-Up of Fixed Charges
G-21, Sub 281; G-21, Sub 286; G-21, Sub 289 (9-12-91)

North Carolina Natural Gas Corporation - Order Authorizing Decrease in Rates Effective February 1, 1991
G-21, Sub 290 (1-29-91)

North Carolina Natural Gas Corporation - Order Authorizing Change in Rates Effective July 1, 1991
G-21, Sub 294 (7-3-91)

North Carolina Natural Gas Corporation - Order Authorizing Change in Rates Effective October 1, 1991
G-21, Sub 296 (10-8-91)

Pennsylvania & Southern Gas Company - Order Allowing Rate Adjustment Effective November 1, 1991
G-3, Sub 169 (11-5-91)

Piedmont Natural Gas Company - Order Approving Public Staff's Proposal to Increase the Gas Cost Savings Decrement in the Rates by $0.25 per Dekatherm
G-9, Sub 300 (2-11-91)

Piedmont Natural Gas Company, Inc. - Order Allowing New Decrement of $0.2899
G-9, Subs 300 and 316 (8-16-91)

Piedmont Natural Gas Company, Inc. - Order Allowing Rate Reduction Effective September 1, 1991
G-9, Sub 317 (9-5-91)

Public Service Company of North Carolina, Inc. - Order Approving Reduction in Rates Associated with Rider D Savings
G-5, Sub 246; G-5, Sub 278 (1-4-91)

Public Service Company of North Carolina, Inc. - Order Approving Filing and Requiring True-up Accounting Entry
G-5, Sub 272 (7-10-19)

Public Service Company of North Carolina, Inc. - Order Approving Adjustment of Temporary Decrements in Rates
G-5, Sub 285 (4-3-91)

Public Service Company of North Carolina, Inc. - Order Allowing Rate Adjustment Effective November 1, 1991
G-5, Sub 288 (11-5-91)

RATES

Piedmont Natural Gas Company - Order Allowing Delay of Reconnection Fee Increase
G-9, Sub 309 (9-5-91)

SECURITIES

North Carolina Natural Gas Corporation - Order Granting Authority to Issue and Sell Debentures
G-21, Sub 297 (10-29-91)

Pennsylvania & Southern Gas Company (North Carolina Gas Service Division) - Order Accepting Settlement
G-3, Sub 157 (3-28-91)

Pennsylvania & Southern Gas Company (North Carolina Gas Service Division) - Order Granting Authority to Enter into a Revolving Loan Agreement
G-3, Sub 166 (1-30-91)

Piedmont Natural Gas Company, Inc. - Order Granting Authority to Issue and Sell 500,000 Shares of Common Stock
G-9, Sub 311 (2-25-91)

Piedmont Natural Gas Company, Inc. - Order Approving Issuance and Sale of Common Stock
G-9, Sub 313 (3-28-91)

Piedmont Natural Gas Company, Inc. - Order Approving Sale of $65,000,000 Principal Amount of Senior Notes
G-9, Sub 314 (7-30-91)

Piedmont Natural Gas Company, Inc. - Order Granting Authority to Issue up to 120,000 Shares of Common Stock
G-9, Sub 318 (10-14-91)

MISCELLANEOUS

North Carolina Natural Gas Corporation - Order Ruling on Motion for Order to Show Cause
G-21, Sub 289 (4-5-91)

North Carolina Natural Gas Corporation and Sonat, Inc. - Order Holding Proceedings in Abeyance
G-21, Sub 291 (7-22-91)

North Carolina Natural Gas Corporation - Order Consolidating Dockets
G-21, Sub 293; G-21, Sub 295 (9-16-91)

Public Service Company of North Carolina, Inc. - Order Ruling on Petition for Order to Show Cause
G-5, Sub 279 (4-5-91)

Public Service Company of North Carolina, Inc. - Order Approving Plan to Offer No-Cost Conversion or Exchange of Customers' Propane Appliances Under Certain Circumstances
G-5, Sub 284 (5-7-91)

MOTOR BUSES

APPLICATIONS WITHDRAWN OR DISMISSED

T.I.M. Couriers, Inc. - Recommended Order Dismissing Application
T-3495 (7-7-91)

ORDERS AND DECISIONS LISTED

AUTHORITY GRANTED - COMMON CARRIER

Company	Charter Operations	Docket No.	Date
B. K. Express, Inc.	Statewide	B-554	7-29-91
B. K. Express, Inc.	(See Order for for Specifics)	B-554, Sub 1	7-30-91
B. K. Express, Inc.	(See Order for for Specifics)	B-554, Sub 2	10-9-91
Carolina Transit Lines of Charlotte, Inc.	Statewide	B-295, Sub 8	3-25-91
Eagle Coach Company Stacy S. Batson, d/b/a	Statewide	B-561	9-13-91
Elegant Transportation, Inc.	Statewide	B-562	9-6-91
Foots, Dorothy Othella	Statewide	B-557	5-7-91
Get-Away Travels, Inc.	Statewide	B-565	10-11-91
Great American Bus of Charleston, Inc.	Statewide	B-555	5-13-91
S & S Bus Lines, Inc.	Statewide	B-566	10-10-91
Travelease Bus Line, Inc.	Statewide	B-510, Sub 2	1-11-91
UBAM Travel & Tours, Inc.	Statewide	B-559	7-25-91

AUTHORIZED SUSPENSION

Company	Certificate	Reason
AT&T Charter Service, Inc.	B-528, Sub 1	Good Cause
Carolina Sightseeing Tours, Inc.	B-516	Good Cause
Cherokee KOA, Sontag, Inc., d/b/a	B-532, Sub 1	Good Cause
Coastal Transport Service, Inc.	B-539, Sub 1	Good Cause

BROKER'S LICENSE

J & J Tours, Joan P. Horne and Joyce P. Miller, d/b/a - Order Granting Broker's License
B-564 (11-13-91)

Let's Go/Lyerly's Elite Travel Service, Rev. Dr. Wilford and Betty C. Lyerly, d/b/a - Order Granting Broker's License
B-558 (5-17-91)

Neebe's Travel Consultant, Alice W. Neebe, d/b/a - Order Granting Broker's License
B-529 (5-3-91)

Pamlico Travel Agency, Joseph McNeil Hoffman, d/b/a - Order Granting Broker's License
B-567 (12-4-91)

Travel Associates, Lynn W. Johnson, d/b/a - Order Granting Broker's License
B-551 (2-28-91)

ORDERS AND DECISIONS LISTED

CERTIFICATES CANCELLED

Bee Line Charter Services, Inc. - Recommended Order Cancelling Operating Authority Certificate No. B-549 - Termination of Liability Insurance Coverage
B-549, Sub 1 (7-9-91)

Cowan Tours, Inc. - Order Cancelling Broker's License
B-340, Sub 1 (3-28-91)

Duke Power Company - Order Cancelling Common Carrier Authority Certificate No. B-209
B-209, Sub 31 (10-31-91)

E. T.'s Country Lane Tours, E. T. Taylor, d/b/a - Order Cancelling Broker's License
B-514, Sub 1 (3-7-91)

Sue's VIP Tours, Bernice Marie King, d/b/a - Recommended Order Cancelling Broker's License
B-490, Sub 2 (7-23-91)

Woodall, Ruth Tours, Ruth Woodall, d/b/a - Order Cancelling Broker's License
B-443, Sub 2 (4-9-91)

SALE AND TRANSFER

Carolina Sightseeing Tours, Inc. - Order Approving Transfer Control of Certificate No. B-516 by Stock Transfer from Sam Habbal to Thomas E. Thompson
B-516, Sub 2 (3-27-91)

MOTOR TRUCKS

APPLICATIONS AMENDED

Bozovich Movers, Archie Thomas Bozovich, d/b/a - Order Amending Application and Allowing Withdrawal of Protest
T-3439 (1-25-91)

Bozovich Movers, Archie Thomas Bozovich, d/b/a - Order Amending Application
T-3439 (2-15-91)

Bryant, Willie - Order Amending Application, Allowing Withdrawal of Protests and Cancelling Hearing
T-3366 (2-7-91)

Cardinal Freight Carriers, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3430 (1-4-91)

Carolina Public Warehouse, Inc. - Order Amending Application and Allowing Withdrawal of Protest
T-3568 (11-13-91)

ORDERS AND DECISIONS LISTED

Choice Furniture Carriers, Thomas A. Riley, d/b/a - Order Amending Application
T-3501 (5-13-91)

Combined Transportation Services, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3575 (12-31-91)

Core Carriers, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3477 (4-25-91)

Cutler Trucking, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3481 (5-17-91)

D & R Services, Donald Revels, d/b/a - Order Amending Application and Allowing Withdrawal of Protest
T-3482 (4-25-91)

D & R Services, Donald Revels, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3482 (5-7-91)

Dew Transport Co., Dew Oil Company, d/b/a - Order Amending Contract Carrier Authority
T-2664, Sub 4 (4-30-91)

Dew Transport Co. - Order Amending Contract Carrier Authority
T-2664, Sub 7 (12-2-91)

Dial Four Delivery, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3567 (11-27-91)

Ennis Heavy Equipment, Edwin I. Ennis, Jr., d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3553 (12-18-91)

ENSCI Corporation - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3410 (2-20-91)

First Delivery and Courier Service, Joan Stephenson, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3502 (5-30-91)

Foothills Delivery, Marshall Wilson Fox and Harold Wayne Burgess, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3472 (5-22-91)

Glover Transport, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3462 (3-27-91)

Hendrix Transport, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3485 (5-1-91)

Hilco Transport, Inc. - Order Amending Application and Allowing Withdrawal of Protest
T-2876, Sub 2 (5-3-91)

Hilco Transport, Inc. - Order Amending Contract Carrier Authority
T-2876, Sub 4 (9-5-91)

Iredell Milk Transportation, Inc. Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-1647, Sub 12 (7-26-91)

Iredell Milk Transportation, Inc. - Order Amending Operating Authority
T-1647, Sub 13 (12-16-91)

Keaton Trucking Company, George Everette Keaton, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3460 (3-20-91)

Langley, William Trucking, William A. Langley, d/b/a - Order Amending Application and Allowing Withdrawal of Protest
T-3516 (6-5-91)

Mayberry Transport, American Petroleum Corporation, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3519 (7-24-91)

McEntire, R. C. Trucking, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-2905, Sub 1 (7-23-91)

Metrolina Courier, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-2648, Sub 1 (1-28-91)

Morgan Trucking, Inc. - Order Amending Application
T-2166, Sub 7 (11-13-91)

New Dixie Transportation Corp. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3573 (12-10-91)

North State Transport, Frank Dills, Dorothy Dills, and Matthew Dills, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-2677, Sub 4 (4-30-91)

ORDERS AND DECISIONS LISTED

Owens, T. W. & Sons Trucking, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3522 (7-22-91)

PDQ Delivery Service, Willie Judge Graham, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3506 (6-5-91)

Paxton Freight Lines, Harold F. Paxton, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3524 (7-31-91)

Pilgrim Express, Joe Elliott Pilgrim, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3566 (11-27-91)

Port City Courier, James Spicer, d/b/a - Order Amending Application, Allowing Withdrawal of Protests and Cancelling Hearing
T-3577 (12-31-91)

Rainbow Transport, Georgia Power, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3458 (3-20-91)

River City Enterprises, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3417 (1-2-91)

S & M Trucking, Edgar Ray Lambert and Dorothy H. Matthews, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3523 (7-25-91)

Santee Carriers, Inc. - Order Amending Contract Carrier Authority
T-1412, Sub 9 (4-15-91)

Santee Carriers, Inc. - Order Amending Contract Carrier Authority
T-1412, Sub 10 (12-4-91)

TeeBerry Express, Inc. - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3552 (10-23-91)

Triple A Moving & Storage, Inc. - Order Amending Application
T-3438 (1-8-91)

United Delivery Service, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3497 (6-3-91)

Wayne, W. Transporation, Inc. - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3446 (2-25-91)

Wilcox Freight, James D. Wilcox, d/b/a - Order Amending Application, Allowing Withdrawal of Protest, and Cancelling Hearing
T-3550 (10-23-91)

Wilson Trucking, Barbara J. Wilson, d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3560 (11-20-91)

Wilson Trucking Co., Walter W. Wilson, Sr., d/b/a - Order Amending Application, Allowing Withdrawal of Protest and Cancelling Hearing
T-3429 (1-14-91)

APPLICATIONS DENIED/DISMISSED

Batchelor Enterprises, Inc. - Recommended Order Denying Application for Common Carrier Authority
T-3406 (2-21-91)

APPLICATIONS WITHDRAWN (COMMON OR CONTRACT CARRIER AUTHORITY)

Company	Docket Number	Date
Electric Transport, Inc.	T-2103, Sub 1	9-20-91
Fleetmaster Express, Inc.	T-3491	8-29-91
Gold Star, Inc.	T-3422	4-9-91
J & W Transport Co. John Paul Jones and John Taylor Woolard, d/b/a	T-3515, Sub 1	7-17-91
Nichols Transport, Inc.	T-3554, Sub 1	10-9-91
Quality Transport & Storage, Eugene S. Dowdy, Lisa D. Howard, and Ruth J. Dowdy, d/b/a	T-3437	7-17-91
Weathers Trucking, Inc.	T-3415	5-8-91

AUTHORITY GRANTED - COMMON CARRIER

Adams, Bobby M., Mobile Home Moving, Bobby M. Adams, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Within a 50-Mile Radius of Chocowinity
T-3411 (7-8-91)

Alexander Crane Service, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Unmanufactured Tobacco and Accessories), and Group 2, Heavy Commodities, Statewide
T-3470 (6-18-91)

American Classic Charters & Tours, Inc. - Order Granting Common Carrier Authority to Transport Passengers in Charter Operations Between all Points and Places in North Carolina
B-552 (4-9-91)

B & B Mobile Home Service, William P. McGhee, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3407 (2-18-91)

B & I Trucking Company, Inc. - Order Granting Common Carrier Authority to Transport Group 21, New Furniture and Furniture Accessories, from Buncombe, Caldwell, and Catawba Counties to all Points within North Carolina
T-3305 (5-28-91)

B & W Trailer Rentals, Burlington Trailer Sales & Service, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Petroleum and Petroleum in Bulk, Statewide
T-3536, Sub 1 (10-14-91)

Baker's Mobile Home Transport, Ronald Lee Baker, Sr., d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Manufactured Houses/Mobile Homes, Statewide
T-3538 (10-17-91)

Barnes and Barnes, Clifford M. Barnes and C. Miller Barnes, Jr., d/b/a - Recommended Order Granting Application for Common Carrier Authority to Transport Group 18, Household Goods, from Moore County to Points in North Carolina and from Points in North Carolina to Moore County
T-2869 (7-22-91)

Berry Mobile Homes, Vaughn E. Berry, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3546 (12-31-91)

Biggs Contract Hauling, Robert Daniel Biggs, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, from Wilson County to Points in North Carolina, and from Points in North Carolina back to Wilson County (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3414 (5-16-91)

Bozovich Movers, Archie Thomas Bozovich, d/b/a - Recommended Order Granting Common Carrier Authority in Part to Transport Group 18, Household Goods, from Guilford and Forsyth Counties to all Points in North Carolina, and from all Points in North Carolina back to Guilford and Forsyth Counties
T-3439 (5-2-91)

Bunch's, Inc. - Recommended Order Granting Application, In Part, Transportation of Group I, General Commodities, (Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco), from Beaufort County to Points in North Carolina, and from Points in North Carolina to Beaufort County
T-3432 (3-20-91)

Bustle Mobile Home Service & Supply, Grady Lee Bustle, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, New and Used Mobile Homes, Manufactured Homes, Mobile Offices, Mobile Classrooms, and Utility Buildings, Statewide
T-3423 (2-26-91)

C & C Mobile Home Movers, Ellerson Rufus Chandler, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3473 (6-12-91)

Cauthen, Steven Mark - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-3443 (3-26-91)

Central Virginia Trucking Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide
T-3490 (9-20-91)

Charwill, Inc. - Order Granting Common Carrier Authority to Transport Group 18, Household Goods, from Robeson County to All Points in North Carolina, and from All Points in North Carolina to Robeson County
T-3543 (10-25-91)

Choice Furniture Carriers, Thomas A. Riley, d/b/a - Order Granting Common Carrier Authority to Transport Group 15, Retail Store Delivery Service, from Points in North Carolina to High Point, and from High Point to Points in North Carolina
T-3501 (8-9-91)

Coastal Transport of Georgia, Inc., Coastal Transport, Inc., d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), and Group 10, Building Materials, Statewide
T-3518 (9-20-91)

Colt Fast Delivery, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities; Except Commodities in Bulk and Unmanufactured Tobacco and Accessories, in Shipments Weighing no more than 22,000 Pounds and no less than 250 Pounds Using Half-ton, Ton, and 20-foot-bed Pick-up Trucks, Between Points in Mecklenburg, Cabarrus, Iredell, and Union Counties
T-2938 (10-25-91)

Core Carriers, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, and Group 5, Solid Refrigerated Products, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorizied.)
T-3477 (6-12-91)

Cutler Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 14, Dump Truck Operations, and Group 21, Liquid Nitrogen, Statewide
T-3481 (7-5-91)

D & D Mobile Home Repairs and Moving, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Statewide
T-2116, Sub 2 (12-31-91)

D & R Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3471 (9-18-91)

Delicate Touch Delivery, Steven R. Ennis, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3451 (4-9-91)

Edwards Wood Products, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3387 (7-17-91)

Elliott, Inc. of Clarksville - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide
T-3557 (11-22-91)

Ellmann Express, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Household Goods, Commodities in Bulk, Classes A & B Explosives, and Unmanufactured Tobacco and Accessories, Between Points in the Counties of Mecklenburg, Union, Gaston, Lincoln, Cabarrus, Catawba, Iredell, Alexander, Rowan, Davie, Davidson, Randolph, Guilford, Alamance, and Forsyth
T-3368 (2-15-91)

Ezzell Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk and Unmanufactured Tobacco); Group 21, Liquid Nitrogen, Liquid Fertilizer, and Liquid Fertilizer Material, in Bulk, in Tank Vehicles; and Group 14, Dump Truck Operations, Statewide (See Note in Official Copy of Order in Chief Clerk's Office)
T-1536, Sub 7 (7-9-91)

First Delivery and Courier Service, Joan Stephenson, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Between Points Within a 35-Mile Radius of Dunn (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3502 (6-13-91)

Fleetmaster Express, Inc. - Recommended Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3491, Sub 1 (8-9-91)

ORDERS AND DECISIONS LISTED

Foothills Delivery, Marshall Wilson Fox and Harold Wayne Burgess, d/b/a - Order Granting Common Carrier to Transport Group 1, General Commodities, Between Points Within a 35-Mile Radius of Hudson (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3472 (6-12-91)

Ford's Contracting Service, William C. Ford, t/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities; Except Commodities in Bulk, in Tank Trucks and Unmanufactured Tobacco; Statewide
T-2081, Sub 6 (1-28-91)

Hall's, Bud Used Auto Parts & Wrecker Service, Jeffery Dalton Hall, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Household Goods, Commodities in Bulk, Classes A & B Explosives, and Unmanufactured Tobacco and Accessories), and Group 13, Motor Vehicles, Statewide
T-3401 (7-5-91)

Hendrix Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3485 (5-21-91)

Hilco Transport, Inc. - Recommended Order Granting Common Carrier Authority to Transport Group 21, Asphalt and Asphalt Cutback, in Bulk, Statewide, Under Contract with Barrus Construction Company, In Part
T-2876, Sub 2 (7-2-91)

Industrial Aid Courier Service, Charles L. Hardin, II, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco, Statewide
T-3572 (12-4-91)

Iredell Milk Transportation, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Commodities Consisting of Dry Sugar and Flour in Bulk Tanker Trucks, from Amstar Sugar Corporation in Charlotte, North Carolina, and Bay State Milling Company in Mooresville, North Carolina, to all Points and Places throughout the State of North Carolina
T-1647, Sub 12 (10-9-91)

Ivey's Towing & Transport, Gary L. Ivey, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities; Except Unmanufactured Tobacco; and Group 10, Building Materials, Statewide
T-3379 (5-28-91)

J & W Transport Co., John Paul Jones and John Taylor Woolard d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3515 (7-17-91)

K & K Mobile Home Movers, Keith Arnold, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points in the Counties of Cumberland, Robeson, Hoke, Harnett, Bladen, Columbus, and Brunswick
T-3468 (11-20-91)

KLLM, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco, Statewide
T-3421 (2-8-91)

Land, Joseph & Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Unmanufactured Tobacco and Accessories), and Group 5, Solid Refrigerated Products, Statewide
T-3386 (4-23-91)

Lawry Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Excluding Tobacco and Hazardous Waste Material), Statewide
T-3517 (9-6-91)

Lighthouse Delivery Service, Larry K. Johns, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Tobacco or Alcoholic Beverages, Statewide
T-3452 (6-24-91)

Lindsay Delivery Service, Inc. - Order Granting Common Carrier Authority to Transport Group 15, Retail Store Delivery Service, Statewide
T-3541 (12-18-91)

Lisk, Howard, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco and Accessories, Statewide
T-1685, Sub 17 (2-25-91)

Lisk, Howard, Inc. - Recommended Order Granting Common Carrier Authority in Part to Transport Group 3, Petroleum and Liquid Petroleum Products, in Bulk in Tank Trucks, Statewide
T-1685, Sub 18 (4-29-91)

MC Transport, Kenneth Myron Colvin, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3412 (2-25-91)

McElheney Homes, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Mobile and Manufactured Homes, Statewide
T-3409 (6-13-91)

McEntire, R. C. Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-2905, Sub 1 (8-12-91)

McLean Mobile Home Moving Service, James C. McLean, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Homes, Between Points in Hoke, Cumberland, Scotland, Robeson, and Moore Counties, and from these Counties to Points in North Carolina
T-3542 (11-20-91)

Metrolina Courier, Inc. - Order Granting Common Carrier Authority to Transport Group 1, and Group 21 (for specifics see Official Copy of Order in Chief Clerk's Office) (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-2648, Sub 1 (3-13-91)

Metropolitan Services, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Cancelled Checks and Interoffice Work for Commercial Banks, Between Points in Mecklenburg and Union Counties
T-3533 (9-24-91)

Mise-Taylor Trucking Company, Charles E. Mise, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3428 (1-4-91)

Murrow's Transfer, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide (Note: The Authority Granted herein, to the Extent it Duplicates any Existing Authority, shall not be Construed as Conveying more than one Operating Right.)
T-90, Sub 7 (2-28-91)

National Modular Home Service, Carolyn Mullenax Smith, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Semi-Trailer and Container Units, from Harnett County and Wake County to all Points and Places in the State of North Carolina, and from all Points and Places in the State of North Carolina to Harnett County and Wake County
T-2943, Sub 2 (9-30-91)

National Spinning Co., Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3424 (3-6-91)

Old Dominion Freight Line, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide (See Note on Official Copy of Order in Chief Clerk's Office.)
T-277, Sub 18 (9-30-91)

Owens, T. W. & Sons Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories; and Group 17, Textile Mill Goods and Supplies, Statewide (Restriction: Transportation of Commodities in Bulk is not Authorized.)
T-3522 (8-21-91)

ORDERS AND DECISIONS LISTED

Parker, Sherwood - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3499 (11-27-91)

Pearce, Hazel - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, and Group 5, Solid Refrigerated Products, Statewide
T-3425 (2-15-91)

Petroleum Transport Company, Inc. - Order Granting Common Carrier Authority to Transport Group 21, Hazardous and Contaminated Materials, in Bulk, Statewide
T-36, Sub 11 (3-15-91)

Pierce Trucking, Ralph I. Pierce, d/b/a - Order Granting Common Carrier Authority to Transport Group 8, Dry Fertilizer and Dry Fertilizer Materials, and Group 21, Liquid Fertilizer, within a 150-Mile Radius of Wilson
T-3469 (12-12-91)

Powell, S. E., Jr., Spencer Evander Power, Jr., d/b/a Order Granting Common Carrier Authority to Transport Group 7, Cotton in Bales, Statewide
T-2763 (1-4-91)

Priority Freight Systems, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3453 (4-23-91)

Riggan Trucking, Charles H. and Glenda Riggan, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Class A & B Explosives, Household Goods, Commmodities in Bulk and Unmanufactured Tobacco), from Granville County to Points in North Carolina and from Points in North Carolina to Granville County
T-3180 (3-20-91)

Rogers, L. J., Jr., Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities; Group 6, Agricultural Commodities; Group 8, Dry Fertilizer and Dry Fertilizer Materials; and Group 14, Dump Truck Operations, Statewide (Restriction: Transportation of Group 19, Unmanfactured Tobacco and Accessories, is not Authorized.)
T-3072 (1-28-91)

Safety Cab Co., Raleigh Cab Company, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, from Wake County and Durham County to all Points in North Carolina Except the Counties of Haywood, Transylvania, Jackson, Swain, Macon, Clay, Graham, and Cherokee (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3419 (4-29-91)

Security Express Services, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, From Gaston and Mecklenburg Counties to all Points in North Carolina (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3347 (5-16-91)

Strickland Repair Shop, Rudy Joe Strickland, d/b/a - Order Granting Common Carrier Authority to Transport Group 21, Mobile Bulk Tobacco Barns, from Edgecombe County to All Points in North Carolina
T-3484 (6-5-91)

System 81 Express, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3464 (4-23-91)

T.I.M.E. Enterprise, Incorporated - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide
T-3511 (8-29-91)

TPL Freightways, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Unmanufactured Tobacco and Commodities in Bulk, and Group 5, Solid Refrigerated Products), Statewide
T-3335 (6-6-91)

Thomas Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3544 (11-15-91)

Thomas Trucking Co., Steve R. Thomas, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco, Statewide
T-3227 (1-4-91)

Transhield Trucking, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3539 (10-14-91)

Tri-State Motor Transit Co. - Order Granting Common Carrier Authority to Transport Group 21, Hazardous and Non-Hazardous Waste, (Except in Bulk, from Points in North Carolina to the Locations of Treatment, Storage, and Disposal Facilities, in North Carolina)
T-2207, Sub 2 (8-1-91)

Triangle Express, Carolina Couriers, Inc., d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide
T-3103, Sub 2 (11-25-91)

Triangle Quality Transport, Inc. - Order Granting Common Carrier Authority to Transport Group 15, Retail Store Delivery Service, Statewide
T-3385 (10-25-91)

Triple A Moving & Storage, Inc. - Order Granting Common Carrier Authority to Transport Group 18, Household Goods, from Robeson County to Points in North Carolina and from Points in North Carolina to Robeson County.
T-3438 (8-14-91)

Two Men and a Truck, Allen and Pirie, Inc., d/b/a - Recommended Order Granting Common Carrier Authority in Part to Transport Group 18, Household goods, from Mecklenburg County to Forsyth and Guilford Counties and from Forsyth and Guilford Counties to Mecklenburg County
T-3397 (1-11-91)

Underwood and Weld Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, 13, 14, 21, 2 (For Specifics see Official Copy of Order in Chief Clerk's Office)
T-1392, Sub 5 (3-7-91)

Unit Transportation, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide
T-3426 (1-28-91)

United Delivery Service, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk and Unmanufactured Tobacco, Between Points on and East of Highway No. 1 (Restriction: Transportation of Shipments Weighing more than 500 Pounds is not Authorized.)
T-3497 (6-19-91)

Wayne, W. Transportation, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, and Group 16, Furniture Factory Goods and Supplies, Statewide (Restriction: Transportation of Group 19, Unmanufactured Tobacco and Accessories, is not Authorized.)
T-3446 (7-5-91)

Williams, Glenn Trucking, Glenn Williams, d/b/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities; Except Unmanufactured Tobacco and Accessories; and Group 10, Building Materials, Statewide
T-3331 (10-9-91)

Wilson Trucking Corporation - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide (Note: The Authority Granted herein, to the Extent it Duplicates any Existing Authority, Shall not be Construed a Conveying more than one Operating Right.)
T-1981, Sub 5 (1-11-91)

ORDERS AND DECISIONS LISTED

Wise Transportation Company, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Unmanufactured Tobacco and Accessories), Between All Points in North Carolina
T-3530 (8-29-91)

Your Express Service, Danny F. Bracken, t/a - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, (Except Umanufactured Tobacco and Accessories), Between Points in the Counties of Guilford, Forsyth, Yadkin, Surry, Stokes, Rockingham, Caswell, Person, Granville, Vance, Franklin, Durham, Orange, Alamance, Randolph, and Davidson
T-3521 (8-1-91)

Zumstein, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, from Vance County to Points in North Carolina
T- 3474 (5-24-91)

Zumstein, Inc. - Order Granting Common Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Between Points in Vance County on the one hand, and on the other, points in North Carolina (See Note on Official Copy of Order in Chief Clerk's Office.)
T-3474, Sub 1 (10-9-91)

AUTHORITY GRANTED - CONTRACT CARRIER

ADM Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (Except Unmanufactured Tobacco), and Group 21, Citric Acid, Sodium Citrate, Potassium Citrate, Chelating Compound, and Equipment, Materials and Supplies used in the Manufactured thereof, Packaged and in Bulk, Dry and Liquid, Statewide, Under Continuing Contract with ADM Citric Acid Division
T-2995, Sub 1 (6-5-91)

ASAP, Yellow Cab Co. of Charlotte, Inc., d/b/a - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide, Under Continuing Contract with International Business Machines Corporation (IBM)
T-3528 (11-15-91)

Atkinson Trucking, William Horace Atkinson, d/b/a - Order Granting Contract Carrier Authority to Transport Group 21, Liquid Fertilizer and Liquid Fertilizer Materials, Statewide, Under Contract with Royster Company
T-3457 (5-13-91)

Biggs, R. D. Transportation, Robert D. Biggs, d/b/a - Order Granting Contract Carrier Authority to Transport Group 21, Pet Food and Pet Food Ingredients, Statewide, Under Continuing Contract with Purina Mills, Inc.
T-3551 (11-15-91)

Bowers & Burrows, Inc. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks, from Apex to Henderson, Warrenton, and Littleton, Under Contract with AAA Gas & Appliance Company
T-3488 (6-7-91)

Burton Lines, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco and Accessories, Statewide, Under Contract with Lowe's Companies, Inc.
T-226, Sub 12 (1-28-91)

Carolina Public Warehouse, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (for Specifics See Official Copy of Order in Chief Clerk's Office) (Restrictions: Transportation of Group 19, Unmanufactured Tobacco and Accessories is not authorized.)
T-3568 (12-12-91)

Centurion Courier, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Trays of Envelopes Containing Food Coupons, from Wake County to Points in North Carolina, Under Continuing Contract with Cost Containment, Inc.
T-3507 (7-3-91)

Cheeseman, John Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco and Accessories, Statewide, Under Continuing Contract with Crown Equipment Corporation
T-3459 (4-15-91)

Chuck's Transports, Inc. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks, from Johnston County to Halifax and Northampton Counties and Return, Under Contract with Blue Flame Fuels, Inc.
T-3450 (3-15-91)

Crawford Deliveries, Incorporated - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide, Under Continuing Contract with BellSouth Services, Incorporated
T-2290, Sub 2 (7-26-91)

Cypress Truck Lines, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Metal or Wood Fence Materials, Between All Points in North Carolina, Under Contract with Southeastern Wire, Inc.
T-3467 (6-6-91)

D & R Services, Donald Revels, d/b/a - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, and Group 12, Explosives and other Dangerous Articles, Statewide, Under Contract with E. I. DuPont DeNemours & Company, Incorporated (For Restrictions See Official Copy of Order in Chief Clerk's Office.)
T-3482 (9-13-91)

Dew Transport Co. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid in Bulk in Tank Trucks, Statewide, Under Continuing Contract with Dew Oil Company
T-2664, Sub 6 (11-26-91)

Ezzell Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide, Under Continuing Contract with Federal Paper Board Company, Inc.
T-1536, Sub 8 (9-13-91)

FOE Trucking, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Emulsion Asphalt, Statewide, Under Contract with Central Oil Asphalt Corporation
T-3483 (5-17-91)

Flying J Transportation, Inc. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid in Bulk in Tank Trucks, Statewide, Under Continuing Contract with CFJ Properties
T-3494 (6-12-91)

GA Distribution - Storage, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco, Statewide, Under Continuing Contract with E. I. DuPont DeNemours & Company, Inc.
T-3440 (4-4-91)

Gilbert Transfer Company - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk in Tank Vehicles and Unmanufactured Tobacco, Statewide, Under Continuing Contracts with J. A. Heard & Associates, Inc.; Superior Manufacturing Company, Inc.; Chesapeake Display & Packaging Company; and Piedmont Traffic Consultants
T-703, Sub 6 (3-8-91)

Glover Transport, Inc. - Order Granting Contract Carrier Authority to Transport Group 12, Explosives and Other Dangerous Articles, Statewide, Under Continuing Contract with Royster Company
T-3462 (5-3-91)

Green Lines Transportation, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities; Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco; Statewide, Under Contract with Wayne Steele, Inc.
T-3527 (10-22-91)

Highway Transport, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Liquid Latex, in Bulk in Tank Vehicles, Statewide, Under Continuing Contract with Rhone Poulenc Company
T-3559 (12-3-91)

Hilco Transport, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Asphalt and Asphalt Cutback, in Bulk, Statewide, Under Continuing Contracts with Riley Paving, Inc.; Triangle Paving, Inc.; Carl Rose & Sons, Inc.; and James R. Vannoy & Sons Contruction Co., Inc.
T-2876, Sub 3 (9-6-91)

Hilley Transport Company, Timothy J. Hilley, d/b/a - Order Granting Contract Carrier Authority to Transport Group 21, Boxes, Fiberboard Without Wooden Frames, Paper Boxes, Corrugated, Flat K.D.F. or Folded Flat, Pulpboard, Noibn Corrugated, not less than 80% Wood Pulp, Waste Paper or Straw Pulp, or Mixture thereof, Statewide, Under Contract with St. Joe Container Company
T-3249 (1-22-91)

Jackson Trading Company, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Statewide, Under Contract with BellSouth Services, Incorporated
T-2082, Sub 2 (5-23-91)

Ledford's Mobile Home Service, Jimmie Ledford, d/b/a - Order Granting Contract Carrier Authority to Transport Group 21, Mobile Homes, from Catawba County to Points in North Carolina, and from Points in North Carolina Back to Catawba County, Under Contracts with Carol Conley Homes, USA Homes, Oakwood Mobile Homes, Inc., and Douglas Home Center
T-3314 (4-2-91)

MAKO Transportation, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Commodities in Bulk in Tank Vehicles, Statewide, Under Continuing Contract with Lee Paving Company
T-3513 (8-12-91)

M & D Trucking, Michael S. Linker & Mearl D. Linker, d/b/a - Order Granting Contract Carrier Authority to Transport Group 9, Forest Products, and Group 10, Building Materials, Statewide, Under Contract with Piedmont Hardwood Lumber Co., Inc., and Durable Wood Preservers, Inc.
T-3405 (3-22-91)

M.S. Carriers, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles and Unmanufactured Tobacco), Statewide, Under Continuing Contract with Amerimark Building Products, Inc.
T-3504 (8-14-91)

Mayberry Transport, American Petroleum Corporation, d/b/a - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks, Statewide, Under Continuing Contracts with J. T. Alexander & Son, Inc., Raymer Oil Company, and Kivett Oil Company
T-3519 (11-22-91)

McGill, Albert - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Between Points within the Counties of Wake, Durham, and Johnston, Under Contract with Adams Products Company (See Note in Official Copy of Order in Chief Clerk's Office.)
T-3222, Sub 1 (7-22-91)

Merit Distribution Services, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Commodities in Bulk; and Group 5, Solid Refrigerated Products, Statewide, Under Continuing Contract with Burger King Distribution Services
T-3416 (1-22-91)

Merritt Trucking Company, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Building Materials; viz: Concrete Dry Mix Adhesives and Grouts, and Decorative and Manufactured Stone, and Ingredients and Raw Materials for their Manufacture, Between all Points in North Carolina, Under Continuing Contract with W. R. Bonsal Co., Inc.
T-2143, Sub 15 (2-15-91)

Merritt Trucking Company, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Commodities in Bulk in Tank Trucks and in Bags, Statewide, Under Continuing Contract with Giles Chemical Corporation
T-2143, Sub 17 (11-26-91)

Mobley Transportation Service, James A. Mobley, d/b/a - Recommended Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, Statewide, Under Continuing Contract with Triangle Pacific Corporation; Champion International Corporation; and Lea Lumber & Plywood Company
T-3461; T-3461, Sub 1 (4-15-91) Final Order Adopting Recommended Order (4-15-91) Order Amending Contract Carrier Authority (5-17-91)

Murrow's Transfer, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco, Statewide, Under Continuing Contract with Thomasville Furniture Industries, Inc.
T-90, Sub 8 (2-26-91)

New South Express, Inc. - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Statewide, Under Contracts with Georgia-Pacific Corporation and Pelican Companies, Inc.
T-3549 (12-16-91)

Petroleum Transport Company, Inc. - Order Granting Contract Carrier Authority to Transport Group 3, Petroleum and Petroleum Products, Liquid, in Bulk in Tank Trucks, Statewide, Under Continuing Contracts with Rainbow Fuels, Ltd. and Tar Heel Oil, Incorporated
T-36, Sub 12 (9-24-91)

Pilgrim Express, Joe Elliott Pilgrim, d/b/a - Order Granting Contract Carrier Authority to Transport Group 21, Iron and Steel Articles, Statewide, Under Continuing Contract with Florida Steel Corporation
T-3566 (12-18-91)

River City Enterprises, Inc. - Order Granting Contract Carrier Authority to Transport Group 6, Agricultural Commodities; Group 8, Dry Fertilizer and Dry Fertilizer Materials; Group 14, Dump Truck Operations; and Group 21, Liquid Fertilizer, Between Points East of and Including Rockingham, Guilford, Randolph, Montgomery, and Richmond Counties, Under Continuing Contracts with Kaiser-Estech, Inc.; Tanglewood Farms, Inc.; and C. A. Perry & Son, Inc.
T-3417 (4-25-91) Errata Order (8-9-91)

Robinson, Joseph E., Jr. - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, Under Bilateral Contract with Adams Products Company from its Plants and Distribution Centers in Durham, Rocky Mount, Edenton, Kinston, Fayetteville, Greenville, Jacksonville, Morrisville, and Wilmington, North Carolina, to Points and Places within the State of North Carolina
T-3486 (5-3-91)

Ryder Distribution Resources, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide, Under Continuing Contract with Gregory Poole Equipment Co.
T-2302, Sub 5 (3-6-91)

Ryder Distribution Resources, Inc. - Order Granting Contract Carrier Authority to Transport Group I, General Commodities, (Except Commodities in Bulk, in Tank Vehicles, and Unmanufactured Tobacco), Statewide, Under Continuing Contract with Stone Heavy Vehicle Specialists
T-2302, Sub 6 (11-15-91)

Starnes, M. Bruce - Order Granting Contract Carrier Authority to Transport Group 2, Heavy Commodities, Statewide, Under Continuing Contract with Square D Company
T-3508 (9-6-91)

Swing Transport, Inc. - Order Granting Contract Carrier Authority to Transport Group 21, Paper and Paper Products, Statewide, Under Continuing Contracts with Gaylord Container Corporation, Georgia-Pacific Corporation, and Packaging Corporation of America, Inc., and divisions of each
T-1819, Sub 5 (8-21-91)

Temple, A. W., Inc. - Order Granting Contract Carrier Authority to Transport Group 10, Building Materials, (for Specific Counties see Official Copy of Order in Chief Clerk's Office)
T-3463 (4-9-91)

The Hales Company, Edwin R. Hales, d/b/a - Order Granting Contract Carrier Authority to Transport Group 2, Heavy Commodities, Statewide, Under Continuing Contracts with B & E Welding & Fabrication, Inc.; Structural Steel Products Corporation; and Structural Coatings, Inc.
T-3445 (3-22-91)

Transport Service Co. - Order Granting Contract Carrier Authority to Transport Group 21, Liquid Latex, in Bulk in Tank Vehicles, Between the Facilities of Rhone Poulenc at or near Gastonia, North Carolina, on the one hand, and on the other, all points in North Carolina
T-2204, Sub 2 (5-13-91)

West Brothers Transfer & Storage, Hauling & Storage Division, Inc. - Order Granting Contract Carrier Authority to Transport Group 1, General Commodities, Except Unmanufactured Tobacco and Accessories, and Group 21, Paper Commodities, from Charlotte to all Points in North Carolina, Under Continuing Contract with Jordan Graphics, Inc.
T-2085, Sub 4 (6-12-91)

AUTHORIZED SUSPENSION

Company	Certificate	Reason
A Nagle/Poor Moving & Storage Co., Inc. T-3268, Sub 1 (3-27-91)	C-741	Good Cause
All American Moving & Storage Company, Inc. T-2023, Sub 2 (1-2-91)	C-1132	Good Cause
American Parcel Service, Inc. T-1154, Sub 9 (4-4-91)	C-817	Good Cause
Atlantic Oil Service, Inc. T-1703, Sub 2 (3-6-91)	P-259	Good Cause
Backwoods Mobile Home Service & Repair, Hugh Zimbelman and Donald Kenneth Ward, Jr. T-2990, Sub 1 (1-28-91)	C-1653	Good Cause
Blount Transit, Inc. T-2631, Sub 2 (3-6-91)	CP-94	Good Cause
Bunch Trucking Company, Inc. T-2056, Sub 4 (11-13-91)	C-1143	Good Cause
Callihan's Mobile Home Service, Johnny Callihan, d/b/a T-3196, Sub 1 (4-26-91)	C-1754	Good Cause
Capitol Van Lines, Inc. T-926, Sub 2 (6-26-91)	C-673	Good Cause

Carolina Relocation Services, Inc. T-2619, Sub 2 (2-25-91)	C-1389	Good Cause
Carolina Storage Corporation T-56, Sub 10 (3-21-91)	CP-76	Good Cause
Colonial Motor Freight, Inc. C-10 (2-26-91)	C-10	Good Cause
Fowler, M. M., Inc. T-72, Sub 7 (12-18-91)	CP-42	Good Cause
Harris Mobile Home Movers, George W. Harris, d/b/a T-2647, Sub 3 (5-23-91)	C-1415	Good Cause
Hill Top Transport, Inc. T-1057, Sub 13 (7-10-91)	P-127	Good Cause
Hollowell Transportation Company T-1389, Sub 3 (11-15-91)	C-942	Good Cause
Honeycutt, J. B. Co., Inc. T-94, Sub 17 (8-2-91)	C-217	Susp. Oper.
Howell Transfer Company, Inc. T-62, Sub 7 (8-22-91)	C-221	Susp. Oper.
Louisiana-Pacific Trucking Company T-2249, Sub 4 (6-6-91)	P-419	Good Cause
Louisiana-Pacific Trucking Company T-2249, Sub 5 (12-5-91)	P-419	Good Cause
Mobile Home Sales and Repair, David L. Cieslinski, d/b/a T-1578, Sub 8 (2-15-91)	C-692	Good Cause
Pearce, Hazel T-3425, Sub 1 (3-1-91)	C-1867	Good Cause
Proctor Trucking Company, Edward Earl Proctor, Jr., t/a T-3338, Sub 1 (1-9-91)	C-1840	Good Cause
Quality Mobile Home Sales of Godwin Turpin Associates, Inc., d/b/a T-2660, Sub 4 (3-21-91)	C-1416	Good Cause
Quality Mobile Home Sales of Godwin, Turpin Associates, Inc., d/b/a T-2660, Sub 4 (10-11-91)	C-1416	Good Cause

Ridgeway Mobile Homes Transporters, Inc. T-2707, Sub 1 (2-15-91)	C-1438	Good Cause
Sellers Mobile Home Set Up Service, Blake T. Sellers, d/b/a T-3237, Sub 1 (1-9-91)	C-1793	Good Cause
Shea, M. J. & Co., Inc. T-3122, Sub 1 (2-20-91)	C-1725	Good Cause
Siler City Mobile Home Movers & Service, Suits Mobile Homes, Inc., d/b/a T-3154, Sub 1 (1-2-91)	C-1711	Good Cause
Smith's Wrecker Service, Etheridge Z. Smith, d/b/a T-3124, Sub 1 (3-27-91)	P-589	Good Cause
Southern Container Corporation T-2981, Sub 1 (4-15-91)	C-1636	Good Cause
2800 Corporation T-2042, Sub 6 (1-9-91)	CP-58	Good Cause
2800 Corporation T-2042, Sub 6 (12-23-91)	CP-58	Good Cause
Walker Contract Service, Max Lee Walker, d/b/a T-3186, Sub 1 (4-26-91)	C-1750	Good Cause
Williams, A. T. Oil Company, Inc. T-3042, Sub 1 (1-30-91)	C-1066	Good Cause

CERTIFICATES/PERMITS CANCELLED

Ceased Operations

Company and Certificate No.	Docket Number	Date
A & F Equipment Service Co., Inc. (C-1509)	T-2807, Sub 2	1-18-91
A & J Motor Lines, Inc. (C-931)	T-1386, Sub 7	2-20-91
Anderson Trucking Co., Lester Wayne Anderson, d/b/a (C-1632)	T-2973, Sub 1	3-1-91
B & W Trailer Rentals, Burlington Trailer Sales and Service, Inc., d/b/a (CP-109)	T-3536, Sub 2	10-24-91
Baker Transportation Company (C-1637)	T-3077, Sub 2	4-23-91
Blount Transit, Inc. (CP-94)	T-2631, Sub 2	2-20-91
Bob's Transport and Storage Co., Inc. (C-1810)	T-3300, Sub 1	2-20-91
Craco Freight Carriers, Inc. (P-600)	T-3185, Sub 2	1-11-91
D and D Contractors, Inc. (P-567)	T-2994, Sub 1	8-29-91
First Delivery and Courier Service Joan Stephenson, d/b/a (C-1896)	T-3502, Sub 1	9-18-91

Glover Transport, Inc. (P-655)	T-3462, Sub 1	8-14-91
Grandpap Mobile Home Service, Inc. (C-968)	T-1600, Sub 3	8-13-91
Interstate Cartage Company, Inc. (P-425)	T-2295, Sub 5	8-14-91
Jenkins, J. W., Inc. (C-229)	T-123, Sub 3	8-9-91
KLLM, Inc. (C-1866)	T-3421, Sub 2	7-3-91
LRC Truck Line, Inc. (P-517)	T-2639, Sub 1	4-19-91
Liberty Trucking Inc. (C-1253)	T-2331, Sub 2	2-15-91
Mullis, Brandon L., Inc. (C-969)	T-1470, Sub 3	6-26-91
PTS of Maryland, Pioneer Transportation Systems, Inc., d/b/a (C-1362)	T-2505, Sub 1	3-21-91
Pearce, Hazel (C-1867)	T-3425, Sub 2	4-30-91
Robinson, Joseph Edward (P-499)	T-2550, Sub 1	3-25-91
Sampson Tobacco Warehouse, Inc. (P-421)	T-2283, Sub 1	10-14-91
United Merchants Trucking, Inc. (P-350)	T-2043, Sub 1	4-19-91
West Brothers Transfer & Storage, Hauling & Storage Division, Inc.	T-2085, Sub 5	4-17-91
Whiteford Transport Systems, Inc. (CP-106)	T-2960, Sub 4	12-12-91

A Christian Moving Co. - Order Affirming Previous Commission Order Cancelling Certificate No. C-1386 Operating Authority
T-2723, Sub 3 (2-25-91)

Atkinson Trucking, William Horace Atkinson, d/b/a - Order Cancelling Operating Authority for Failure to Comply with Commission Rule R2-22
T-3457 (6-20-91)

B & W, James Wallce, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1552 - Termination of Liability and Cargo Insurance Coverage
T-2850, Sub 2 (4-16-91)

Biggs Contract Hauling, Robert Daniel Biggs, d/b/a - Order Cancelling Operating Authority for Failure to Comply with Commission Rule R2-22
T-3414 (6-20-91)

Bright Belt Motor Lines, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-104 - Termination of Cargo Insurance Coverage
T-511, Sub 12 (10-15-91)

Building Systems Transportation, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1262 - Termination of Liability Insurance Coverage
T-2367, Sub 5 (1-7-91)

C.J.S. Courier Service, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1441 - Termination of Liability Insurance Coverage
T-2967, Sub 1 (6-11-91)

CTB Trucking, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1627 - Termination of Liability and Cargo Insurance Coverage
T-2947, Sub 1 (9-24-91)

ORDERS AND DECISIONS LISTED

Coastal Moving Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-617 - Termination of Cargo Insurance Coverage
T-1643, Sub 3 (2-19-91)

Cook's Transfer & Storage Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1335 - Termination of Liability Insurance Coverage
T-2528, Sub 2 (5-13-91)

Davis Trucking, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1449 - Termination of Cargo Insurance Coverage
T-3267, Sub 1 (7-23-91)

Executive Delivery Service, Locklar Enterprises, Inc., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1824 - Termination of Liability and Cargo Insurance Coverage
T-3316, Sub 2 (11-18-91)

Forbes Refrigerated Transport, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1040 - Termination of Liability and Cargo Insurance Coverage
T-1710, Sub 5 (2-5-91)

Fouts House/Mobile Home Movers, Austin Fouts, Jr., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1805 - Termination of Liability Insurance Coverage
T-3270, Sub 1 (6-11-91)

Grant Enterprises, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1551 - Termination of Cargo Insurance Coverage
T-2859, Sub 4 (11-18-91)

HWT, Inc., Hazardous Waste Transport, Inc., d/b/a - Recommended Order Cancelling Operating Authority Certificate No.C-1644 - Termination of Liability Insurance Coverage
T-3037, Sub 1 (4-29-91)

Helms Mobile Home Towing, Paul Ray Helms, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1447 - Termination of Liability Insurance Coverage
T-2726, Sub 1 (7-9-91)

Hinson Trucking, Otis McKenzie Hinson, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1846 - Termination of Liability and Cargo Insurance Coverage
T-3339, Sub 2 (3-5-91)

Hunt's Trucking Co., Gilbert Hunt, d/b/a - Recommended Order Cancelling Operating Authority Permit No. P-533 - Termination of Liability Insurance Coverage
T-2700, Sub 1 (4-29-91)

Jerry's Mobile Home Service & Movers, Jerry W. Craig, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1440 - Termination of Cargo Insurance Coverage
T-2702, Sub 3 (4-16-91)

Jordan Mobile Home Movers, Ronnie Long Jordan, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1728 - Termination of Cargo Insurance Coverage
T-2684, Sub 5 (10-28-91)

Joyful Homes, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1005 - Termination of Cargo Insurance Coverage
T-1575, Sub 7 (10-15-91)

McGill, Albert - Recommended Order Cancelling Operating Authority Permit No. P-621 - Termination of Liability Insurance Coverage
T-3222, Sub 2 (8-27-91)

Mise-Taylor Trucking, Charles E. Mise, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1861 - Termination of Liability and Cargo Insurance Coverage
T-3428, Sub 1 (6-11-91)

Motor-Rail Transport Company, Vacation, Inc., d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-783 - Termination of Liability Insurance Coverage
T-3303, Sub 1 (7-23-91)

Native American Trucking Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1522 - Termination of Cargo Insurance Coverage
T-2803, Sub 4 (12-16-91)

Pee Dee Express, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1829 - Termination of Liability Insurance Coverage
T-3284, Sub 1 (12-16-91)

Ratley Mobile Home Service, Neil Ratley, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1125 - Termination of Cargo Insurance Coverage
T-1723, Sub 9 (3-20-91)

S & S Transport, Ralph Ray Smith and Claude David Searcey, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. C-1781 - Termination of Cargo Insurance Coverage
T-3257, Sub 1 (11-18-91)

SAS Wrecker Service, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1630 - Termination of Cargo Insurance Coverage
T-3000, Sub 5 (1-29-91)

Senn Trucking Company - Recommended Order Cancelling Operating Authority Certificate/Permit No. CP-69 - Termination of Liability Insurance Coverage
T-1932, Sub 3 (8-27-91)

TSC Expres Company - Recommended Order Cancelling Operating Authority Certificate No. C-1446 - Termination of Liability and Cargo Insurance Coverage
T-2725, Sub 2 (1-29-91)

Tedder, Foster Sr. - Recommended Order Cancelling Operating Authority Permit No. P-464 - Termination of Liability Insurance Coverage
T-2428, Sub 2 (1-29-91)

Tedder, Foster Sr. - Recommended Order Cancelling Operating Authority Permit No. P-464 - Termination of Liability Insurance Coverage
T-2428, Sub 2 (9-4-91)

Thomas, R. P. Trucking Company, Incorporated - Recommended Order Cancelling Operating Authority Certificate No. C-1399 - Termination of Liability Insurance Coverage
T-2658, Sub 1 (4-16-91)

Thorne's Transport & Service, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-1225 - Termination of Cargo Insurance Coverage
T-3354, Sub 1 (10-15-91)

Watts Trucking Company, Elford Daley Watts, d/b/a - Recommended Order Cancelling Operating Authority Certificate No. CP-73 - Termination of Cargo Insurance Coverage
T-2357, Sub 3 (12-16-91)

Welch Moving & Storage Company, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-697 - Termination of Cargo Insurance Coverage
T-950, Sub 7 (11-18-91)

Wilmington Oil & Moving Service, Inc. - Recommended Order Cancelling Operating Authority Certificate No. C-663 - Termination of Liability and Cargo Insurance Coverage
T-2183, Sub 2 (4-16-91)

RESCINDING CANCELLED AUTHORITY

Company	Docket Number	Date
C.J.S. Courier Service, Inc.	T-2967, Sub 1	11-25-91
Coastal Moving Company, Inc.	T-1643, Sub 3	2-25-91
D & B Mobile Home Service, Inc.	T-3340, Sub 1	2-8-91
Grant Enterprises, Inc.	T-2859, Sub 4	12-10-91
HWT, Inc., Hazardous Waste Transport, Inc., d/b/a	T-3037, Sub 1	5-22-91
Hunt's Trucking Co., Gilbert Hunt, d/b/a	T-2700, Sub 1	5-20-91

Jordan Mobile Home Movers, Ronnie Long Jordan, d/b/a	T-2684, Sub 4	2-19-91
Joyful Homes, Inc.	T-1575, Sub 7	12-20-91
Paradise Trucking, Inc.	T-3217, Sub 2	3-25-91
Tedder, Foster Sr.	T-2428, Sub 2	2-12-91
Wilmington Oil & Moving Service, Inc.	T-2183, Sub 2	11-22-91

W. Everette Company, Inc. - Recommended Order Rescinding Suspension Order - Termination of Cargo Insurance Coverage
T-2968, Sub 2 (1-15-91)

COMPLAINTS

Dixie Trucking Company, Inc. - Recommended Order in Complaint of Coville, Inc.
T-299, Sub 8 (5-8-91)

MERGER

Transit Express of Charlotte, Inc. - Order Approving Merger of Certificate No. C-1681 with Pronto Delivery, Inc., Certificate No. C-1240
T-3062, Sub 2 (1-11-91)

NAME CHANGE/TRADE NAME

A-1 Specialized Transport, Inc. - Order Approving Name Change from A-1 Wrecker Service of Chatham County, Inc., for Certificate No. C-1157
T-3601 (12-20-91)

Aaron Fortson Services, Inc. - Order Approving Name Change from Dan Randall Leasing Corporation, d/b/a Fortson Trucking Company
T-2747, Sub 2 (9-4-91)

Advantage Moving and Storage Services, Inc. - Order Approving Name Change from Amundsen Moving and Storage, Inc.
T-3578 (11-13-91)

Airport Transportation Service, Inc. - Order Approving Name Change from Airport Ground Transportation Service, Inc.
T-2209, Sub 2 (4-26-91)

B & W Trailer Rental, Burlington Trailer Sales & Service, Inc., d/b/a - Order Approving Name Change from Burlington Trailer Sales and Service, Inc., for Certificate/Permit No. CP-109
T-3536 (10-11-91) Errata Order (12-10-91)

Carolina Creditor Services, Michael W. Jarman & Michael G. Wiggins, d/b/a - Order Approving Name Change from Michael W. Jarman & Michael W. Baldwin, d/b/a Carolina Creditor Services
T-3408, Sub 1 (2-18-91)

Cauthen, Terry Trucking, Inc. - Order Approving Name Change from Terry D. Cauthen, d/b/a Terry Cauthen Trucking for Certificate No. C-1785
T-3222, Sub 1 (12-18-91)

Cooper's Mobilehome Moving Service, Inc. - Order Approving Name Change from Timothy B. Cooper, d/b/a Cooper's Mobile Home Movers & Service Co. for Certificate No. C-1727
T-3163, Sub 1 (10-11-91)

David Mobile Home Moving, James Lloyd Davis, d/b/a - Order Approving Name Change from James Lloyd David and Rita Roberts Davis, d/b/a Davis Mobile Home Moving for Certificate No. C-1466
T-2745, Sub 3 (1-15-91)

Eastern Flatbed Systems, Inc. - Order Approving Name Change from Eastern Flatbed Systems, Inc., d/b/a Senn Transport for Certificate/Permit No. CP-69
T-3591 (11-25-91)

Express Mobile Home Movers, Inc. - Order Approving Name Change from Greg Oliver, d/b/a Express Mobile Home Movers
T-2762, Sub 2 (9-11-91)

Goldsboro Trucking Company - Order Approving Name Change from Robert F. McLaurin, t/a Henry Faircloth Trucking for Certificate No. C-1506
T-3600 (12-18-91)

Haigler Trucking Company - Order Approving Name Change from Aubrey Haigler, d/b/a Haigler Trucking Company for Certificate No. C-802
T-1133, Sub 6 (6-14-91)

Harvel's, Cliff Moving Company, Inc. - Order Approving Name Change from Cliff Harvel's Moving Company, for Certificate No. C-634
T-1912, Sub 3 (3-18-91)

J & S Truck Service, E R Trucking, Inc., d/b/a - Order Approving Name Change from J & S Truck Service, Inc., for Certificate No. C-1274
T-2350, Sub 2 (1-25-91)

Kendall Trucking, Larry R. & John M. Kendall, d/b/a - Order Approving Name Change from Larry R. Kendall, Kendall Trucking & Grading for Permit No. P-175, and Dismissing Show Cause Hearing
T-1829, Sub 2; T-1829, Sub 3 (6-20-91)

Kendall Trucking, John M. Kendall, d/b/a - Order Approving Name Change from Larry R. Kendall and John M. Kendall, d/b/a Kendall Trucking Company, for Permit No. P-175
T-1829, Sub 4 (7-26-91)

Lend Lease Dedicated Services, Inc. - Order Approving Name Change from Whiteford Dedicated Services, Inc., for Certificate No. CP-106
T-3448 (1-15-91)

ORDERS AND DECISIONS LISTED

Liberty Trucking Inc. - Order Approving Name Change from Jack Respess and Stephen Hall, d/b/a Liberty Trucking for Certificate No. C-1253
T-2331, Sub 1 (1-28-91)

Mitchell Brothers Moving, Inc. - Order Approving Name Change from Daniel I. Mitchell, d/b/a Mitchell Brothers Moving MBM for Certificate No. C-1588
T-2882, Sub 1 (8-14-91)

Mullen, Henry Trucking, Inc. - Order Approving Name Change from Henry Henderson Mullen, d/b/a Henry Mullen's Trucking
T-2478, Sub 3 (11-1-91)

Parsons Trucking Company - Order Approving Name Change from G. G. Parsons Trucking Company for Certificate No. C-1057
T-1784, Sub 8 (1-18-91)

Port City Transfer and Storage Company, Richard G. Beaver and Charles Thad Linker, d/b/a - Order Approving Name Change from John S. Templeton and Charles Thad Linker, d/b/a Port City Transfer and Storage Company for Certificate No. C-620
T-1491, Sub 4 (10-15-91)

Riverside Mobile Home Movers, Inc. - Order Approving Name Change from Billy D. Ivey, d/b/a Riverside Mobile Home Movers for Certificate No. C-936
T-2588, Sub 2 (1-18-91)

Single Source Transportation, Co. - Order Approving Name Change from Sooner Transport Corporation
T-3514 (4-26-91)

Temperature Controlled Carriage, Inc. - Order Approving Name Change from Ryder Temperature Controlled Carriage, Inc., for Certificate No. C-1479
T-3476 (2-28-91)

Thomas Transport System, Inc. - Order Approving Name Change from Thomas Produce Company of Mount Airy, Inc., for Certificate No. C-1403
T-2629, Sub 2 (5-15-91)

Transport Service Co. - Order Approving Name Change from Transport Service Co., d/b/a Transport Service Co. of Butner for Permit No. P-106
T-2204, Sub 2 (2-12-91)

Triangle Services Corporation - Order Approving Name Change from RDP Associates, Inc., d/b/a Triangle North American, for Certificate No. C-1856
T-3520 (5-24-91)

Your Express Service, Inc. - Order Approving Name Change from Danny F. Bracken, t/a Your Express Service
T-3521, Sub 1 (8-13-91)

ORDERS AND DECISIONS LISTED

RESCINDING NAME CHANGE

Company	Docket Number	Date
J & S Truck Service, E R Trucking, Inc., d/b/a	T-2350, Sub 2	1-31-91
Whiteford Transport Systems, Inc.	T-2960, Sub 3	12-2-91

RATES - MOTOR COMMON CARRIERS

Barrett Mobile Home Transport - Order Allowing 10% Increase not to Exceed 45 days, due to Increased Fuel Costs
T-696 (2-14-91)

Central Transport, Inc. - Recommended Order Allowing Rate Increase, Scheduled to Become Effective on June 1, 1991
T-740, Sub 15 (5-30-91) Order Adopting Recommended Order (5-30-91)

Fleet Transport Company, Inc. - Recommended Order Allowing Rate Increase
T-1436, Sub 7 (7-26-91) Order Adopting Recommended Order (7-29-91)

Matlack, Inc. - Cancellation Order to Amend Intrastate Tariff
T-696 (6-7-91)

Motor Common Carriers - Recommended Order Approving General Increase in Rates and Charges Applicable to Shipments of General Commodities, Including Minimum Charges
T-825, Sub 317 (4-8-91) Order Adopting Recommended Order (4-8-91)

Motor Common Carriers - Recommended Order Vacating Order of Investigation and Allowing Tariff Filing to Become Effective as Scheduled
T-825, Sub 318 (6-13-91) Order Allowing Recommended Order to be Effective June 15, 1991 (6-13-91)

North Carolina Trucking Association, Inc. - Cancellation Order
T-696 (4-16-91)

North Carolina Trucking Association, Inc. - Recommended Order Allowing Rate Increase in Various Rates and Charges Published in Petroleum Tariff No. 5-X, NCUC 172 Scheduled to Become Effective on December 11, 1991, and Various Rates and Charges Published in Asphalt Tariff No. 16-L, NCUC 171, Scheduled to Become Effective on January 1, 1992
T-825, Sub 319 (12-11-91) Order Adopting Recommended Order (12-12-91)

Roadway Package System, Inc. - Recommended Order Allowing Rate Increase
T-3003, Sub 2 (7-18-91) Order Allowing Recommended Order (7-18-91)

United Parcel Service, Inc., (an Ohio Corporation) - Recommended Order Approving Supplement No. 8 to Tariff North Carolina Utilities Commission No. 5
T-1317, Sub 28 (2-18-91) Order Allowing Recommended Order to be Effective February 18, 1991 (2-18-91)

ORDERS AND DECISIONS LISTED

Wilson Trucking Corporation - Cancellation Order
T-696 (4-16-91)

SALES AND TRANSFER/CHANGE OF CONTROL

ATH, Arkansas Transit Homes, Inc., d/b/a - Recommended Order Granting Application for Sale and Transfer of Certificate No. C-1822 from Boyce G. Dew, Dew's Mobile Home Transport
T-3449 (6-21-91)

ATH, Arkansas Transit Homes, Inc., Inc., d/b/a - Final Order Overruling Exceptions and Affirming Recommended Order for Sale and Transfer of Certificate No. C-1822 from Boyce C. Dew, d/b/a Dew's Mobile Home Transport (Commissioner Wright dissents.)
T-3449 (8-2-91)

All Points Mobile Home Transporting, James M. Petree, III, d/b/a - Order Approving Sale and Transfer of Certificate No. C-1436 from Richard S. Webster, d/b/a The Satellite Station
T-3444 (2-18-91)

American Moving & Storage, Inc. - Order Approving Sale and Transfer of a Portion of Certificate No. C-1389 from Carolina Relocation Services, Inc.
T-3465 (4-12-91)

B & J Mobile Home Parts and Service, Lewis Gordon Powell, d/b/a - Order Approving Sale and Transfer of Certificate No. C-993 from Richard Edwin Bullock
T-3492 (5-20-91)

Black, Donald Mobile Home Service, Donald Gene Black, d/b/a - Order Approving Transfer of Certificate No. C-1126 from Clyde V. Starling, d/b/a Starling's Mobile Home Service
T-3487 (4-18-91)

Brookshire Express Service, Ronald J. Dunn, d/b/a - Order Approving Sale and Transfer of Certificate No. C-1315 from Buddy Brookshire, d/b/a Brookshire Express Services
T-2460, Sub 1 (9-20-91)

Bunch's, Inc. - Order Approving Sale and Transfer of Certificate No. C-741 from A Nagle/Poor Moving & Storage Co., Inc.
T-3432, Sub 1 (7-18-91)

Campbell and Son Transfer and Storage, Steven Wayne Campbell, d/b/a - Order Approving Sale and Transfer of Certificate No. C-1737 from John E. Carter, d/b/a Carter's Transfer
T-3556 (10-23-91)

Courier Dispatch Group, Inc. - Order Approving Application of Certificate No. C-1616 for Change of Control Through Stock Transfer
T-3110, Sub 1 (8-23-91)

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Dew Transport Co. - Order Approving Sale and Transfer of Permit No. P-520 from Dew Oil Company, d/b/a Dew Transport Co.
T-2664, Sub 5 (9-20-91) Errata Order (11-25-91)

Economy Transport, Inc. - Order Approving Transfer of Control of Economy Transport, Inc., Holder of Certificate No. C-114, by Stock Transfer from Pace Oil Co., Inc., to Timothy C. Lail and Billy L. Talton
T-1468, Sub 3 (6-14-91)

Ezzell Trucking, Inc. - Order Approving Transfer of Control for Young Transfer, Inc., d/b/a Young Transfer by Stock Transfer from Terry L. Welch and Norma D. Welch to Ezzell Trucking, Inc.
T-1536, Sub 9 (10-25-91)

Family Dollar Trucking, Inc. - Order Approving Sale and Transfer of Certificate No. C-1718 from Family Dollar Stores, Inc.
T-3540 (9-20-91)

Gemini Transportation Services, Inc. - Order Approving Transfer to Acquire Control of Gemini Transportation Services, Inc., Holder of Certificate No. C-1686, by Stock Transfer from IU Truckload, Inc., to Landstar Holding Corporation
T-3086, Sub 1 (4-18-19)

Goldsboro Van & Storage, Inc. - Order Approving Sale and Transfer of Certificate No. C-673 from Capitol Van Lines, Inc.
T-1594, Sub 2 (7-18-19)

Hilco Transport, Inc. - Order Approving Sale and Transfer of Certificate/Permit No. CP-14 from Southern Oil Transportation Co., Inc.
T-2876, Sub 1 (2-19-91)

Hunt, J. B. Transport, Inc. - Order Approving Sale and Transfer of Certificate No. C-196 from Bulldog Trucking, Inc.
T-3479 (4-18-91)

Independent Freightway, Incorporated - Order Approving Transfer to Acquire Control of Independent Freightway, Incorporated, Holder of Certificate No. C-1395, by Stock Transfer from IU Truckload, Inc., to Landstar Holding Corporation
T-2643, Sub 2 (4-18-19)

J & S Truck Service, E R Trucking, Inc., d/b/a - Order Approving Sale and Transfer of Certificate No. C-1274 from J & S Truck Service, Inc.
T-2350, Sub 3 (3-15-91)

Jim's Mobile Home Moving & Service, Inc. - Order Approving Sale and Transfer of Certificate No. C-1653 from Hugh Zimbelman and Donald Kenneth Ward, Jr., d/b/a Backwoods Mobile Home Service and Repair
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Johnson Brothers Truckers, Inc. - Order Approving Sale and Transfer of Certificate No. C-1339 from Amtruc, Inc., d/b/a Johnson Truckers
T-3480 (4-18-19)

McGill Specialized Carriers, Inc. - Order Approving Transfer of Certificate No. C-377, by Stock Transfer from McGil Group, Inc., to TRISM, Inc.
T-2650, Sub 1 (5-20-91)

Mobile Home Transit, Leonard Keith Frady, d/b/a - Order Denying Application for Sale and Transfer of Certificate No. C-1692 from Jerry David Boyd, d/b/a Mobile Home Transit
T-3116, Sub 1 (5-1-91)

Nilson Van & Storage, Inc. - Order Approving Sale and Transfer of Certificate No. C-173 from American Distribution Systems, Inc.
T-3498 (5-20-91)

Ranger Transportation, Inc. - Order Approving Transfer to Acquire Control of Ranger Transportation, Inc., Holder of Certificate No. C-1652, by Stock Transfer from IU Truckload, Inc., to Landstar Holding Corporation
T-3009, Sub 1 (4-18-19)

Rogers, L. J., Jr., Trucking, Inc. - Order Approving Sale and Transfer of a Portion of Certificate No. C-1389 from Carolina Relocation Services, Inc.
T-3072, Sub 1 (4-15-91)

Senn Transport, Eastern Flatbed Systems, Inc., d/b/a - Order Approving Sale and Transfer of Certificate/Permit No. CP-69 from Senn Trucking Company
T-3558 (10-22-91)

Southern Oil/Tidewater Fuels, Inc. - Order Approving Sale and Transfer of Certificate No. C-1501 from Tidewater Fuels, Inc.
T-3441 (2-19-91)

Swift Transportation Co., Inc. - Order Approving Sale and Transfer of Certificate No. C-1347 from Arthur H. Fulton, Inc.
T-3545 (9-30-91) Errata Order (10-16-91)

Tobacco Contractors, Inc. - Recommended Order Approving Application for Sale and Transfer of a Portion of Certificate/Permit No. CP-76 from Carolina Storage Corporation
T-3496 (8-29-91)

Tobacco Contractors, Inc. - Final Order Overruling Exceptions and Affirming Recommended Order for Sale and Transfer of a Portion of Certificate/Permit No. CP-76 from Carolina Storage Corporation
T-3496 (9-30-91)

Truck One, Inc. - Order Approving Transfer of Certificate No. C-1477 from Natrol Express, Inc.
T-3531 (8-21-91)

W & B Trucking, Inc. - Order Approving Sale and Transfer of Certificate No. C-1803 from Rapid Distribution Service, Inc.
T-3489 (4-18-19)

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Chemical Leaman Tank Lines, Inc. - Recommended Order Approving Tariff Filing for Investigation of Proposed Increase in Rates Applying on Commodities in Bulk, Tariff NCUC No. 8, Scheduled to Become Effective on May 1, 1991
T-663, Sub 26 (4-26-91) Order Allowing Recommended Order to be Effective May 1, 1991 (4-30-92)

DSI Transports, Inc. - Recommended Order Vacating Order of Investigation and Allowing Tariff Filing to Become Effective as Scheduled
T-3049, Sub 1 (9-12-91) Order Allowing Recommended Order to Become Effective September 15, 1991 (9-12-91)

Matlack, Inc. - Recommended Order Approving Tariff Filing for Investigation of Proposed Increases in Rates and Charges Including Justification Procedures Applicable on Shipments of Liquid Chemicals and Petrochemicals
T-2281, Sub 3 (7-12-91) Order Allowing Recommended Order to Be Effective July 15, 1991 (7-12-91)

Merritt Trucking Company - Recommended Order Approving Tariff Filing for Investigation of Proposed Increase in Rates and Charges Published in Liquefied Petroleum Gas Tariff NCUC No. 18 Scheduled to Become Effective on January 1, 1992
T-2143, Sub 19 (12-31-91) Order Allowing Recommended Order to Be Effective January 1, 1992 (12-31-91)

Wendell Transport Corporation, (WTC) - Recommended Order Approving Investigation of Proposed Increase in Rates Applying on Fertilizer, Supplement for Tariff 8, NCUC No. 8, Scheduled to Become Effective on January 27, 1991
T-1039, Sub 17 (1-28-91) Order Adopting Recommended Order (1-28-91)

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Builders Transport, Inc. - Order Granting Request to Self-Insure
T-1638, Sub 9 (4-17-19)

Courier Dispatch Group, Inc. - Order Approving Pledge of Certificate No. C-1616
T-3110, Sub 2 (10-2-91)

Gilbert Transfer Company - Order Amending Permit No. 68 to reflect the contracting shipper as Chesapeake Display and Packaging Company
T-703, Sub 8 (1-31-91)

KLLM, Inc. - Order Granting Request to Self-Insure
T-3421, Sub 1 (3-20-91)

Taylor's, J. D. Mobile Home Service, Inc. - Order Denying Request to Reinstate Certificate No. C-1745
T-2992, Sub 1 (10-16-91)

RAILROADS

APPLICATIONS AMENDED OR WITHDRAWN

Southern Railway Company - Order Allowing Withdrawal of Petition
R-29, Sub 698 (2-28-91)

Southern Railway Company - Order Allowing Withdrawal of Petition
R-29, Sub 699 (2-28-91)

MOBILE AGENCY AND NONAGENCY STATIONS

Norfolk Southern Railway Company - Order Granting Application to Close the Barber, North Carolina Agency and Place Barber and Its Nonagency Stations Under the Jurisdiction of Linwood, North Carolina
R-4, Sub 149 (7-18-91)

Norfolk Southern Railway Company - Recommended Order Granting Application on a Six-month Trial Basis to Discontinue Agency Operations at Statesville, and Place Statesville and its Nonagency Stations Under the Jurisdiction of Mobile Agency Route NC-5 Based at Hickory
R-4, Sub 153 (10-23-91)

Southern Railway Company - Recommended Order Approving Application on a Six-Months' Trial Basis
R-29, Sub 889 (1-28-91)

SIDE TRACKS AND TEAM TRACKS - Order Granting Petition/Authority to Retire and Remove Track

CSX TRANSPORTATION, INC.

Docket Number	Date	Track	Town
R-71, Sub 188	9-13-91	Track No. 3	Bethel

NORFOLK SOUTHERN RAILWAY COMPANY

Docket Number	Date	Track	Town
R-4, Sub 158	12-12-91	Track No. 287-33, Mile Post 286.6	Greensboro

SOUTHERN RAILWAY COMPANY (NORTH CAROLINA RAILROAD COMPANY)

Docket Number	Date	Track	Town
R-29, Sub 550	3-15-91	Track No. 1	Biltmore
R-29, Sub 671	3-7-91	Mile Post VF-41.74	Fayetteville
R-29, Sub 816	5-13-91	0-21-1, Mile Post 0-20.2	Cornelius
R-29, Sub 850	5-10-91	261-10, 261-12	Reidsville
R-29, Sub 875	2-5-91	262-1, Mile Post 261.1	Reidsville

R-29, Sub 878	4-17-91	2-5, Mile Post L 1.1	Winston-Salem
R-29, Sub 885	3-25-91	Mile Post CF-72	Greensboro
R-29, Sub 919	2-27-91	"Q"NW	Durham
R-29, Sub 920	1-18-91	Serving R. J. Reynolds Tobacco Company	Greenville
R-29, Sub 921	1-18-91	Serving R. J. Reynolds Tobacco Company	Kinston
R-29, Sub 923	3-5-91	Mile Post H-20.0	Burlington
R-29, Sub 933	3-25-91	Mile Post 417	Grover
R-29, Sub 935	3-25-91	Mile Post CF-70.3	Greensboro
R-29, Sub 937	1-8-91	Serving Coggin Enterprises	High Point
R-29, Sub 940	1-9-91	1-3, Mile Post L-0.5	Winston-Salem
R-29, Sub 942	1-18-91	Serving Reynolds Tobacco	Wilson
R-29, Sub 943	1-8-91	28-12, Mile Post K-21.4	Winston-Salem
R-29, Sub 948	3-5-91	24-15, Mile Post H-23.5	Graham
R-29, Sub 951	2-13-91	6-2, Mile Post L-5, Plus 995 Feet Serving Poindexter Lumber Co.	Frontis
R-29, Sub 952	5-24-91	Serving R. J. Reynolds	Winston-Salem
R-29, Sub 953	1-18-91	Mile Post H-22	Burlington
R-29, Sub 955	1-18-91	Serving Carey Wholesale Co.	Method

NAME CHANGE

Norfolk Southern Railway Company - Order Approving Name Change from Southern Railway Company
R-4, Sub 148 (8-9-91)

TRANSFER

CSX Transportation, Inc. - Recommended Order Approving Transfer of Spruce Pine Transportation Service Agency to Its Transportation Service Center at Kingsport, Tennessee
R-71, Sub 182 (2-25-91)

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APPLICATIONS CANCELLED, WITHDRAWN OR DENIED

Affinity Fund, Inc. - Order Allowing Withdrawal of Application
P-233 (1-3-91)

BSN Telecom Company - Order Denying Request for Confidentiality
P-269 (10-14-91)

BSN Telecom Company - Order Denying BSN's Request for Confidential Treatment of Income Statement
P-269 (10-17-91)

Cellcom of Hickory, Inc., Advertising Practices of - Order Allowing Withdrawal of Petition and Closing Docket
P-228, Sub 2 (7-2-91)

ORDERS AND DECISIONS LISTED

Corporate Telemanagement Group, Inc. - Order Denying Motion for Temporary Authority to Provide Resell Telecommunications Services
P-252 (7-2-91)

Ellerbe Telephone Company - Order Allowing Withdrawal of Petition and Closing Docket
P-21, Sub 53 (10-15-91)

Excel Telecommunications, Inc. - Order Denying Application without Prejudice
P-270 (10-15-91)

GSF Cellular, Inc. - Order Allowing Withdrawal of Application Without Prejudice
P-229 (1-8-91)

Gillen, Mary D. - Order Allowing Withdrawal of Application
SC-679 (7-1-91)

Long Distance America, Savannah Telco, Inc., d/b/a - Order Denying Application Without Prejudice to Provide Intrastate Interexchange Telecommunications on a Resale Basis
P-268 (9-17-91)

One Call Communications, Inc. - Order Denying Request for Temporary Operating Authority to Provide Intrastate Telecommunications Services
P-264 (8-20-91)

One Call Communications, Inc. - Order Denying US Sprint's Motion for Reconsideration
P-264 (10-17-91)

TFN Marketing Company, Inc. - Order Denying Application Without Prejudice
P-259 (8-13-91)

TELNET Communications, Inc. - Order Allowing Withdrawal Without Prejudice
P-242 (3-4-91)

Vanguard Cellular Systems of Coastal Carolina, Inc. - Order Cancelling Certificate
P-208, Sub 4 (10-21-91)

WATS/800, Inc. - Order Denying Application Without Prejudice
P-274 (10-9-91)

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ATC Long Distance - Recommended Order Granting Certificate to Provide Intrastate Interexchange Resell Telecommunications Services
P-235 (2-8-91) Order Allowing Recommended Order to Become Effective (2-12-91)

Affinity Fund, Inc. - Order Ruling on Motion for Reconsideration for a Certificate of Public Convenience and Necessity to Provide Intrastate Telecommunications Service
P-233, Sub 1 (5-21-91)

Affinity Fund, Inc. - Recommended Order Granting Certificate to Provide Intrastate Telecommunications Service
P-233, Sub 1 (6-14-91) Order Allowing Recommended Order to Become Final (6-18-91)

Allnet Communication Service, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Resell Telecommunications Services
P-244 (5-2-91)

Alumni Network, Convergent Communications, Inc., d/b/a - Recommended Order Granting Certificate to Operate as a Reseller of InterLATA Telecommunications Services Within North Carolina
P-276 (11-25-91) Order Allowing Recommended Order to Become Final (11-26-91)

American Telephone Network, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services on a Resell Basis
P-256 (8-29-91)

Blue Ridge Cellular Telephone Company - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Services and for Approval of Initial Tariff Containing Rates, Charges, and Regulations
P-236 (2-1-91)

Business Choice Network, Inc. - Recommended Order Granting Certificate of Public Convenience and Necessity to Operate as a Reseller of Interexchange Long Distance Services in North Carolina
P-254 (7-18-91)

CTG Telecommunications, Inc. - Recommended Order Granting Certificate of Public Convenience and Necessity as a Non Facilities Based Switchless Reseller of Telecommunications Services
P-271 (11-7-91) Order Allowing Recommended Order to Become Final (11-13-91)

Carolina Telephone and Telegraph Company - Recommended Order Granting Certificate to Provide Wholesale and Retail Cellular Mobile Telecommunications Service in North Carolina RSA Nos. 7, 8, 9, 10, 12 and 13, and Approving Initial Tariff
P-7C, Subs 750, 751, 752, 753, 754 and 755 (9-6-91) Order Allowing Recommended Order to be Effective September 6, 1991 (9-6-91)

Carolina West Cellular Company in RSA 3 and Carolina West Cellular II in RSA 2 - Recommended Order Granting Certification to Provide Wholesale and Retail Cellular Mobile Telecommunications Services to North Carolina RSA No. 3 and Portions of North Carolina RSA No. 2 and Approving Initial Tariff
P-247 (9-4-91) Order Allowing Recommended Order to Become Effective (9-6-91)

ORDERS AND DECISIONS LISTED

Cellular One, Clear Communications Partnership, d/b/a - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Service and for Approval of Initial Tariff Containing Rates, Charges and Regulations
P-285 (11-27-91) Order Allowing Recommended Order to Become Final (12-3-91)

Cellular One, SDK Enterprises, d/b/a - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Services, to Resell Long Distance Services, to Offer Wide Area Call Reception Service and for Approval of Initial Tariff Containing Rates, Charges and Regulations
P-275 (10-28-91) Order Allowing Recommended Order to Become Final (10-29-91)

Cellular Services of Asheville, Asheville Metronet, Inc., d/b/a - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Services and for Approving Initial Tariff
P-186, Sub 7 (7-12-91)

Centel Cellular Company of Hickory Limited Partnership - Order Granting Interim Construction Authority for a Certificate to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-240 (3-27-91)

Centel Cellular Company of Hickory Limited Partnership - Recommended Order Granting Certificate for Approval of Initial Rates, Charges, and Regulations, and for Authority for the Resale of Toll Services to Provide Wholesale and Retail Cellular Mobile Telecommunications Services to Portions of North Carolina RSA No. 2
P-240 (6-12-91)

Contel Cellular, North Carolina RSA 1 Partnership, d/b/a - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Services, to Resell Long Distance Services and for Approval of Initial Tariff Containing Rates, Charges and Regulations
P-278 (12-11-91) Order Allowing Recommended Order to Become Final (12-17-91)

Corporate Telemangement Group, Inc. - Recommended Order Granting Application Subject to Refund to Provide Intrastate Resale Telecommunications Services
P-252 (8-13-91)

EXECUTONE Information Systems, Inc. - Recommended Order Granting Certificate to Provide Intrastate InterLATA Long Distance Telecommunications Services on a Resale Basis and for Approval of Rates
P-280 (12-3-91) Order Allowing Recommended Order to Become Final (12-10-91)

G.M.D. Limited Partnership - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-241 (2-12-91)

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G.M.D. Limited Partnership - Recommended Order Granting Certificate to Provide Retail and Wholesale Cellular Radio Communications Services and for Approval of Initial Tariff Containing Rates, Charges and Regulations
P-241 (6-12-91) Order Allowing Recommended Order to Become Final (6-18-91)

International Telecommunications Exchange Corporation - Recommended Order Granting Certificate of Public Convenience and Necessity to Provide Intrastate Interexchange Resale Telecommunications Service
P-277 (11-7-91) Order Allowing Recommended Order to Become Effective (11-13-91)

Matrix Telecom - Recommended Order Granting Certificate to Operate as a Reseller of Interexchange Long Distance Services in North Carolina
P-224 (1-15-91)

North Carolina RSA 5 Cellular Partnership - Recommended Order Granting Certificate and Approving Rates
P-227 (2-5-91) Order Allowing Recommended Order to Become Effective (2-19-91)

North Carolina RSA 5 Cellular Partnership - Order Granting WACR Authority for a Certificate of Public Convenience and Necessity and for Approval of Initial Rates, Charges and Regulations
P-227 (8-21-91)

North Carolina RSA 6, Inc. - Recommended Order Granting Certificate and Approving Rates
P-243 (8-15-91) Order Allowing Recommended Order to Become Effective (8-16-91)

North Carolina RSA 6 Limited Partnership - Recommended Order Granting Certificate to Provide Wholesale and Retail Cellular Mobile Telecommunications Service in North Carolina RSA No. 6, and Approving Initial Tariff
P-251 (9-6-91) Order Allowing Recommended Order to be Effective September 6, 1991 (9-6-91)

North Carolina RSA 9, Inc. - Recommended Order Granting Certificate and Approving Rates
P-258 (11-15-91) Order Allowing Recommended Order to Become Final (11-19-91)

North Carolina RSA 10, Inc. - Recommended Order Granting Certificate and Approving Rates
P-245 (8-15-91) Order Allowing Recommended Order to Become Final (8-16-91)

North Carolina RSA 15 Cellular Partnership - Recommended Order Granting Certificate and Approving Rates
P-225 (2-5-91) Order Allowing Recommended Order to Become Effective (2-19-91)

North Carolina RSA 15 North Sector Limited Partnership - Recommended Order Granting Certificate of Public Convenience and Necessity, and for Approval of Initial Rates, Charges and Regulations to Provide Wholesale and Retail Cellular Mobile Telecommunications Services to Portions of North Carolina RSA No. 15
P-232 (2-20-91)

North Carolina RSA 15 North Sector Limited Partnership - Order Granting Authority for the Resale of Toll Services
P-232 (4-4-91)

RSA 15 Cellular Partnership - Order Granting WACR Authority for a Certificate of Public Convenience and Necessity and for Approval of Initial Rates, Charges and Regulations
P-225 (8-21-91)

PHOENIX NETWORK, INC. - Recommended Order Granting Certificate to Provide Intrastate Telecommunications Service
P-239 (11-22-91) Order Allowing Recommended Order to Become Final (11-26-91)

Saluda Mountain Cellular Telephone Company - Recommended Order Granting Certificate of Public Convenience and Necessity and Approving Rates
P-234 (3-14-91) Order Allowing Recommended Order to Become Final (3-19-91)

Teledial America of North Carolina, Inc. - Recommended Order Granting Certificate to Provide Intrastate Interexchange Telecommunications Services on a Resell Basis
P-266 (9-27-91) Order Allowing Recommended Order to Become Effective (10-1-91)

TELNET Communications, Inc. - Recommended Order Granting Certificate to Provide Intrastate Telecommunications Services
P-242, Sub 1 (7-30-91) Order Allowing Recommended Order to Become Final (8-6-91)

Tri-County Cellular Telephone Company - Recommended Order Granting Certificate of Public Convenience and Necessity and Approving Rates
P-230 (3-14-91) Order Allowing Recommended Order to Become Final (3-19-91)

US WATS, Inc. - Recommended Order Granting Certificate of Public Convenience and Necessity to Operate as a Reseller of Telecommunications Services within the State of North Carolina
P-260 (10-25-91) Order Allowing Recommended Order to Become Final (10-29-91)

USCOC of North Carolina RSA #8, Inc. - Recommended Order Granting Certificate and Approving Rates
P-249 (10-15-91) Order Allowing Recommended Order to Become Final (10-21-91)

CERTIFICATES AMENDED

ALLTEL Cellular Associates of the Carolinas - Order Granting Motion to Amend Certificate of Public Convenience and Necessity Authorizing Resale of Long Distance Service
P-149, Sub 11 (8-21-91)

Centel Cellular Company of North Carolina; Centel Cellular Company of Hickory; Raleigh-Durham MSA Limited Partnership; Telespectrum, Inc. (formerly United Telespectrum Inc.) and Virginia Metronet d/b/a Centel Cellular Company of Virginia - Order Granting Motion to Amend Certificates of Public Convenience and Necessity for Their Existing Certificates to Provide for Resale of Toll Services
P-148, Sub 13; P-150, Sub 20; P-157, Sub 28; P-190, Sub 3; P-206, Sub 6 (5-31-91)

Saluda Mountain Cellular Telephone Company - Order Allowing Motion to Amend Application for a Certificate of Public Convenience and Necessity and for Approval of Initial Rates, Charges and Regulations
P-234 (2-21-91)

Tri-County Cellular Telephone Company - Order Allowing Amendment for Approval of Initial Rates, Charges and Regulations
P-230 (2-6-91)

COMPLAINTS

AT&T - Order Closing Docket in Complaint of Sarah Taylor
P-140, Sub 31 (9-6-91)

Carolina Telephone Company - Order Closing Docket in Complaint of Sandra Schwab
P-7, Sub 746 (2-18-91)

Centel Cellular of North Carolina - Order Closing Docket in Complaint of George V. Kontos
P-150, Sub 9 (4-10-91)

Centel Cellular of North Carolina - Order Closing Docket in Complaint of Mark Sheffield
P-150, Sub 15 (2-27-91)

GTE South - Order Closing Docket in Complaint of Steve Winter
P-19, Sub 241 (5-23-91)

GTE South; GTE Directories Sales Corporation; GTE Directories Service Corporation; and GTE Directories Distribution Corporation - Recommended Order Declaring Complaint Moot and Closing Docket in Complaint of R. L. Truelove
P-19, Sub 245 (10-28-91)

MCI Telecommunications Corporation - Order Accepting Settlement and Closing Docket in Complaint of Margaret Bos
P-141, Sub 16 (4-5-91)

Southern Bell Telephone and Telegraph Company - Order Closing Docket in Complaint of Ricky Whitley, President and Chris Whitley, Vice President, d/b/a Whitley Antiques, Inc.
P-55, Sub 935 (4-18-19)

Southern Bell Telephone and Telegraph Company - Order Closing Docket in Complaint of Carolina Voice Mail
P-55, Sub 947 (8-8-91)

Southern Bell Telephone and Telegraph Company - Order Closing Docket in Complaint of Pamela Bennett
P-55, Sub 951 (12-4-91)

Southern Bell Telephone and Telegraph Company - Order Closing Docket in Complaint of Joseph M. Thompson
P-55, Sub 955 (8-7-91)

Southern Bell Telephone and Telegraph Company - Order Dismissing Complaint in Complaint of Joseph Hall and Closing Docket
P-55, Sub 957 (11-21-91)

Southern Bell Telephone and Telegraph Company - Order Dismissing Complaint for Lack of Jurisdiction in Complaint of Richard L. Coleman and Betty B. Coleman
P-55, Sub 958 (11-21-91)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Corporation - Final Order Dismissing Complaint of Atlantic Tree Service & Landscaping and Closing Docket
P-89, Sub 40 (7-30-91)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company - Order Continuing Restraining Order Pending Hearing and Decision; Order Scheduling Hearing on Complaint on February 13, 1991, in Complaint of AccuTek Computers
P-89, Sub 41 (1-10-91)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company - Order Closing Docket in Complaint of AccuTek Computers
P-89, Sub 41 (2-22-91)

Southern Bell Telephone and Telegraph Company and BellSouth Advertising and Publishing Company - Order Overruling Motions to Dismiss, Scheduling Hearing, and Serving Additional Complaint in Complaint of Joan G. Potter
P-89, Sub 42 (12-16-91)

EXTENDED AREA SERVICE (EAS)

Carolina Telephone and Telegraph Company - Order Authorizing Beaufort County Extended Area Service and Aurora to New Bern Extended Area Service
P-7, Sub 741 (1-4-91)

Carolina Telephone and Telegraph Company - Order Authorizing Trenton and Pollocksville to New Bern Extended Area Service
P-7, Sub 742 (1-4-91)

Carolina Telephone and Telegraph Company - Order Approving Warrenton to Henderson and Littleton Extended Area Service and Norlina to Henderson Extended Area Service
P-7, Sub 743 (2-6-91)

Carolina Telephone and Telegraph Company - Order Excluding Fairmont Exchange and Requiring No-Protest Notice
P-7, Sub 744 (8-7-91)

Carolina Telephone and Telegraph Company - Order Approving Robeson County Extended Area Service
P-7, Sub 744 (10-9-91)

Carolina Telephone and Telegraph Company and Heins Telephone Company - Order Excluding Siler City and Authorizing No Protest Notice
P-7, Sub 745 (8-7-91)

Carolina Telephone and Telegraph Company and Heins Telephone Company - Order Approving Extended Area Service - Bonlee, Goldston, and Pittsboro to Sanford
P-7, Sub 745 (10-9-91)

Carolina Telephone and Telegraph Company - Order Authorizing Poll of Franklin County Extended Area Service
P-7, Sub 748 (3-13-91)

Carolina Telephone and Telegraph Company - Order Approving Franklin County Extended Area Service
P-7, Sub 748 (6-26-91)

Carolina Telephone and Telegraph Company - Order Authorizing Poll of Trenton to Kinston Extended Area Service
P-7, Sub 749 (3-20-91)

Carolina Telephone and Telegraph Company - Order Authorizing No-Protest Notice - Trenton to Kinston Extended Area Service
P-7, Sub 749 (6-19-19)

Carolian Telephone and Telegraph Company - Order Approving Implementation of Extended Area Service - Trenton to Kinston
P-7, Sub 749 (9-11-91)

Carolina Telephone and Telegraph Company - Order Authorizing Poll - Coharie to Dunn Extended Area Service
P-7, Sub 756 (5-21-91)

Carolina Telephone and Telegraph Company - Order Approving Implementation of Extended Area Service - Coharie to Dunn Extended Area Service
P-7, Sub 756 (12-18-91)

Carolina Telephone and Telegraph Company - Order Authorizing No-Protest Notice Plymouth to Pike Road and Pinetown - Extended Area Service
P-7, Sub 757 (6-10-91)

Carolina Telephone and Telegraph Company - Order Approving Extended Area Service for Plymouth to Pike Road and Pinetown
P-7, Sub 757 (7-30-91)

Carolina Telephone and Telegraph Company - Order Authorizing EAS Poll - Gibsonville to Greensboro Extended Area Service
P-7, Sub 762 (10-4-91)

Carolina Telephone and Telegraph Company - Order Authorizing EAS Poll - Havelock, Morehead City, and Newport Extended Area Service
P-7, Sub 767 (11-19-91)

Central Telephone Company - Order Authorizing Poll - Sherrills Ford to Denver Extended Area Service
P-10, Sub 450 (12-3-91)

Southern Bell Telephone and Telegraph Company - Order Authorizing Polling in Denver Exchange (Commissioner Wright voted "no".)
P-55, Sub 934 (4-10-91)

Southern Bell Telephone and Telegraph Company - Order Authorizing No-Protest Notices - Denver, Huntersville, Lincoln County, and Iredell County Extended Area Service
P-55, Sub 934 (4-10-91)

Southern Bell Telephone and Telegraph Company - Order Denying Southern Bell's Motion for Reconsideration
P-55, Sub 934 (6-26-91)

Southern Bell Telephone and Telegraph Company - Order Approving Denver, Huntersville, Lincoln County and Iredell County Extended Area Service
P-55, Sub 934 (7-2-91) Errata Order (7-3-91)

Southern Bell Telephone and Telegraph Company - Order Authorizing Extended Area Service - Denver, Huntersville, Lincoln County, and Iredell County
P-55, Sub 934 (9-17-91)

Southern Bell Telephone and Telegraph Company - Order Approving Extended Area Service - Hickory, Maiden, and Sherrills Ford
P-55, Sub 941 (7-10-91)

Southern Bell Telephone and Telegraph Company - Order Allowing Plan to go into Effect to Offer Experimental Rutherford County Seat Calling Plan
P-55, Sub 945 (1-29-91)

Southern Bell Telephone and Telegraph Company - Order Denying Orange County Extended Area Service
P-55, Sub 953; P-55, Sub 952 (9-27-91)

Triangle J Council of Governments - Order Extending Expiration Date on Experimental Plans for Toll-Free Calling in the Triangle J Region
P-55, Sub 888 (3-12-91)

ORDERS AND DECISIONS LISTED

INTERIM CONSTRUCTION AUTHORITY

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 7.
P-7C, Sub 750 (5-7-91)

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 8
P-7C, Sub 751 (5-7-91)

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 9
P-7C, Sub 752 (5-7-91)

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 10
P-7C, Sub 753 (5-7-91)

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 12
P-7C, Sub 754 (5-7-91)

Carolina Telephone and Telegraph Company - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in RSA No. 13
P-7C, Sub 755 (5-7-91)

Carolina West Cellular, North Carolina RSA 2 Cellular Telephone Company, d/b/a - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-248 (4-23-91)

Carolina West Cellular, North Carolina RSA 3 Cellular Telephone Company, d/b/a - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges, and Regulations
P-247 (4-23-91)

Cellular One, Clear Communications Partnership, d/b/a Order Granting Interim Construction Authority for Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges and Regulations
P-285 (10-15-91) Errata Order (10-17-91)

Cellular Services of Asheville, Asheville Metronet, Inc., d/b/a - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Telecommunications Services and for Approval of Initial Tariff Containing Rates, Charges, and Regulations
P-186, Sub 7 (5-14-91)

GSF Cellular, Inc., and United States Cellular Corporation - Order Granting Interim Construction for a Certificate of Public Convenience and Necessity to be Issued in the Name of North Carolina RSA No. 6, Inc., and for Approval of Initial Rates, Charges and Regulations
P-243 (4-23-91)

ITC Cellular, Inc. - Order Granting Interim Construction Authority to Provide Wholesale and Retail Cellular Mobile Telecommunications Services in North Carolina RSA No. 11
P-284 (10-8-91)

North Carolina RSA #6 Limited Partnership - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-251 (5-7-91)

North Carolina RSA #1, Bruce G. Patterson, d/b/a - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications Services and for Approval of Initial Rates, Charges, and Regulations
P-257 (6-7-91)

North Carolina RSA #9, Inc. - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and for Approval of Initial Rates, Charges, and Regulations
P-258 (6-18-91)

North Carolina RSA 1 Partnership - Order Granting Interim Construction Authority to Provide Wholesale Cellular Radio Communications Services, to Resell Long Distance Services, and Approval of Initial Rates, Charges, and Regulations
P-278 (9-24-91)

North Carolina RSA #11, Inc. - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges, and Regulations
P-279 (10-1-91)

Randolph Cellular Telepone Company - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges, and Regulations
P-290 (12-10-91) Errata Order (12-10-91)

SDK Enterprises - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Telecommunications Services, to Resell Long Distance Services, to Offer Wide Area Call Reception Service, and for Approval of Initial Rates, Charges, and Regulations
P-275 (8-27-91)

USCOC of North Carolina RSA #10, Inc. - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-245 (4-23-91)

USCOC of North Carolina RSA #8, Inc. - Order Granting Interim Construction Authority to Provide Retail and Wholesale Cellular Radio Communications and for Approval of Initial Rates, Charges and Regulations
P-249 (6-7-91)

USCOC of North Carolina RSA #7, Inc. - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges and Regulations
P-272 (9-17-91)

USCOC of North Carolina RSA #2, Inc. - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges, and Regulations
P-287 (12-3-91)

Virginia Cellular Limited Partnership - Order Granting Interim Construction Authority for a Certificate of Public Convenience and Necessity and Approval of Initial Rates, Charges, and Regulations
P-253 (8-6-91)

NAME CHANGE

Dial Page, L. P. - Order Approving Name Change to Dial Page, Limited Partnership
P-172, Sub 12 (8-27-91)

LDDS of Carolina, Inc. - Order Allowing Name Change from Phone America of Carolina, Inc.
P-283 (10-8-91)

Wynn-Hill, Inc. - Order Allowing Name Change to Wynn Communications Group, Inc.
P-184, Sub 2 (10-23-91)

RATES

GTE Mobilnet (Five Cellular Companies Controlled by GTE) - Order Disapproving Filings without Prejudice to Increase Roamer Charges
P-152, Sub 19; P-153, Sub 24; P-181, Sub 14; P-197, Sub 11; P-196, Sub 10 (2-21-91)

Southern Bell Telephone and Telegraph Company - Order Modifying Proposed Rate Increase Between Mooresville and Statesville and Troutman
P-55, Sub 934 (3-5-91)

SALES AND TRANSFER

Central Telephone Company - Order Approving Transfer of Catawba County Portion of the Valdese Exchange to the Hickory Exchange
P-10, Sub 451 (12-3-91)

Coastal Carolina Communications, Inc.; Anserphone of Goldsboro, Inc. - Order Approving Transfer of Authority
P-126, Sub 14; P-95, Sub 4 (12-5-91)

Contel Office Communications, Inc. - Order Allowing Transfer of Special Certificate for the Provision of Shared and/or Resold Telephone Service to RealCom Office Communications, Inc.
STS-4; STS-5 (2-20-91)

GTE Mobile Communications, Inc. - Order Approving Transfer of Control of Asheville Metronet to GTE Mobile Communications, Inc.
P-186, Sub 6 (6-4-91)

GTE South, Inc. - Order Approving Contract and Deferring Accounting Treatment of Gain for Consent and Approval to the Sale of Certain of Its Real Property to GTE Mobilnet of the Southeast, Inc.
P-19, Sub 244 (11-7-91)

GTE South, Incorporated - Order Approving Accounting Treatment for Consent and Approval to the Sale of Certain of Its Real Property to GTE Mobilnet of the Southeast, Incorporated
P-19, Sub 244 (12-16-91)

Phone America of Carolina, Inc., and LDDS Communications, Inc. - Order Approving Transfer of the Stock Ownership and Control of the Operating Franchise of Phone America to LDDS and for Approval of Financing Arrangements
P-166, Sub 9 (2-18-91)

RSA Growth Partnership - Order Approving Transfer of Certificate and Tariff to RS II Partnership
P-226, Sub 1 (4-2-91)

Saluda Mountain Telephone, Service Telephone Company, Barnardsville Telephone Company - Order Approving Transfer of Control of Saluda Mountain Telephone Company, Service Telephone Company, and Barnardsville Telephone Company from Telephone Data Systems, Inc., to TDS Telecommunications Corporation
P-76, Sub 29; P-60, Sub 52; P-75, Sub 40 (1-25-91)

Saluda Mountain Cellular Telephone Company - Order Approving Change in Ownership from Telephone and Data Systems, Inc., to United States Cellular Corporation
P-234, Sub 1 (6-19-19)

ORDERS AND DECISIONS LISTED

SECURITIES

ALLTEL Carolina, Inc. - Order Approving Loan from the Rural Telephone Bank
P-118, Sub 63 (4-2-91)

Cellcom of Hickory, Inc. - Order Approving the Pledge of Assets and Financing
P-228, Sub 1 (3-21-91)

Ellerbe Telephone Company, Inc. - Order Approving Loan from the Rural Electrification Administration
P-21, Sub 52 (4-5-91)

Ellerbe Telephone Company, Inc. - Order Approving Loan from the Rural Electrification Administration - Amended
P-21, Sub 52 (12-19-91)

First Fayette Cellular Corporation - Order Approving Issuance of Additional Shares of Common Stock
P-223, Sub 1 (6-4-91)

GTE Corporation - Order Approving Contract Relating to Inter-Company Loans and Interest
P-128, Sub 30 (12-18-91)

Metro Mobile CTS of Charlotte, Inc. - Order Approving Transfer of Stock to Bell Atlantic Corporation
P-155, Sub 12 (12-23-91)

Metro Mobile CTS of Charlotte, Inc. - Order Approving Authority to Enter into a Loan and Security Arrangement with Motorola, Inc.
P-155, Sub 14 (12-23-91)

Prime Paging, L.P. - Order Granting Transfer of the Assets and Radio Common Carrier Operating Authority for the Jacksonville, Wallace, and Wilmington, North Carolina Areas
P-237 (2-6-91)

Tri-County Cellular Telephone Company - Order Approving United States Cellular Corporation to Acquire 49% Interest of its Parent, TDS, in Tri-County Cellular Telephone Company and the 51% Interest of Tri-County Telephone Membership Corporation
P-230, Sub 1 (5-28-91)

SPECIAL CERTIFICATES

Docket Number	Date	Company
SC-3, Sub 4	11-14-91	Coin Telephone, Inc. (Reissuing)
SC-91	4-15-91	Jack Andrews (Reinstated)
SC-473	5-23-91	Telaleasing Enterprises, Inc.
SC-541, Sub 2	12-13-91	London Communications, Inc. (Reissuing)

ORDERS AND DECISIONS LISTED

SC-612	1-3-91	Mary Ann Newman
SC-613	1-3-91	Gary T. Cliett
SC-614	1-23-91	Equal Access Corporation
SC-615	1-23-91	Anthony G. Bowling
SC-616	1-23-91	Wayne J. Martin
SC-618	2-5-91	Central Carolina Trading Company
SC-619	2-5-91	Ray Trevathan
SC-620	2-5-91	Eden Drug, Inc.
SC-621	2-12-91	Reidsville Pharmacy, Inc.
SC-622	2-12-91	IBA Telecom, Inc.
SC-623	2-19-91	Mrs. Rosalie Byrd
SC-624	2-19-91	Nanette Guilford
SC-625	2-19-91	Michael Warren
SC-627	3-5-91	Wayne Ledbetter
SC-628	3-5-91	Atlantic Telco
SC-629	3-12-91	North Davie Junior High School
SC-630	3-13-91	Craig Lunsford
SC-631	3-12-91	Edneyville High School
SC-632	3-12-91	Clyde Harriger
SC-633	3-18-91	Robert M. Paczkoski
SC-634	3-18-91	Joel K. Scales
SC-635	3-26-91	Larry H. Bethune
SC-636	4-4-91	Rick Moore
SC-637	4-4-91	Tim Lewis
SC-638	4-4-91	Roger G. Franklin, Jr.
SC-639	4-4-91	Lewis Summers
SC-640	4-19-91	Gladys Kirby
SC-641	4-19-91	Brintle Enterprises, Inc.
SC-642	4-19-91	Alan Mercer
SC-643	4-19-91	Roger Popkin
SC-644	4-19-91	Bill Pappas
SC-645	5-8-91	Rockingham Center Pharmacy, Inc.
SC-647	5-8-91	Asheville Mall, Inc.
SC-648	5-8-91	Special Operator Services, Inc.
SC-649	5-10-91	James C. Bibey
SC-650	5-30-91	Bonnie Schley
SC-651	5-30-91	Mario A. Marsico
SC-652	5-30-91	James S. Umstead
SC-653	5-30-91	Pisgah High School
SC-655	5-30-91	Dennis A. Robison
SC-656	5-30-91	J. Graham Singleton
SC-657	5-31-91	John M. Fortson and Norman J. Fortson
SC-658	6-3-91	Sushil Kashyap
SC-659	6-3-91	William T. and Ruth Long
SC-660	6-3-91	Tyrone and Janene Shackleford
SC-661	6-3-91	Medical Facilities of America LXVIII, d/b/a Charlotte Health Care Center
SC-662	6-3-91	J. Edward Evans and Linda L. Evans
SC-663	6-3-91	Nolan Leonard
SC-664	6-20-91	William G. Davis, Jr.
SC-665	6-20-91	Carolyn Tedder
SC-666	6-20-91	D. N. Black, d/b/a The Nor/Haz Companies

SC-667	6-20-91	Thomas A. Hamme, Jr.
SC-668	6-20-91	Robert J. Glass
SC-669	6-20-91	Charles Barbours and Richard Berry
SC-670	6-20-91	Carlson S. Howerton
SC-671	6-21-91	C. Eugene Montgomery
SC-672	6-21-91	John T. Hayes
SC-673	6-21-91	Edward L. Holt
SC-674	6-21-91	L. Craig Jones and Terry A. Jones
SC-675	6-27-91	Robert A. Jeffries and Renee G. Arriola d/b/a R. & B. Marketing
SC-676	6-27-91	Keith R. Bowman
SC-677	6-27-91	Robert H. A. Ballin
SC-678	6-27-91	BHB Payphone, Inc.
SC-680	7-23-91	Toy J. Lathan
SC-681	7-23-91	James W. Hitch
SC-682	8-15-91	Pay Phones Incorporated
SC-683	7-31-91	Harvey Brown
SC-684	7-31-91	Gokulesh Corporation
SC-685	7-31-91	Arnold and Shirley Brown
SC-686	7-31-91	Garry Kennedy
SC-687	7-31-91	Ernest Duvall
SC-688	8-20-91	Darlene Hanford, d/b/a Gaycom
SC-689	8-20-91	Southeast High School/Halifax County
SC-690	8-20-91	Warren County High School
SC-691	8-20-91	Northwood High School
SC-692	8-20-91	Northern Vance High School
SC-693	8-20-91	Jerry C. Sparks
SC-694	8-20-91	Northwest High School/Halifax County
SC-695	8-27-91	Eastern Randolph High School
SC-696	8-27-91	Fred T. Foard High School
SC-697	9-6-91	George Maloomain
SC-698	9-6-91	Edgcomb Metals Company
SC-699	9-17-91	George R. Wooten, Jr., d/b/a Eastern Telephone Service
SC-700	9-17-91	Alfred Ma
SC-701	9-17-91	Adams Products Company
SC-702	9-17-91	Todd Faw
SC-703	9-17-91	Gary D. Treece
SC-704	9-24-91	Dan M. Howle, Jr.
SC-705	10-7-91	Arm Communications Company, Albert R. Miner, d/b/a
SC-706	10-7-91	Ronald Ramsey
SC-707	10-7-91	Victor Steed and Greg Marshall
SC-708	10-9-91	Bald Head Island Management, Inc.
SC-709	10-9-91	Donald E. Axberg
SC-710	10-10-91	R. Don Hoke
SC-711	10-22-91	Persepolis, Inc., Jala Montazeri, d/b/a
SC-712	10-22-91	Executone Information Systems, Inc.
SC-713	10-28-91	Larry E. Scott
SC-714	10-28-91	Jerry Mazzurco
SC-715	10-28-91	Spencer Pee, Jr.
SC-716	10-28-91	Ronald Molloy & James Scales, Jr.
SC-717	10-28-91	JTR Enterprises, Inc.

SC-718	11-6-91	Richard Clayton
SC-719	11-6-91	Gene Lewis
SC-720	11-18-91	Edward L. Fortune
SC-721	11-18-91	Tom's Food and Fuel, Boyce L. O'Tuel, Jr., d/b/a
SC-722	11-18-91	Le Star Pharmacy Corporation
SC-723	12-4-91	Ronald C. Summerlin
SC-724	12-4-91	Supercade Amusements, Inc.
SC-275	12-23-91	James F. Rees, Jr.
STS-6	6-17-91	Business Services of North Mecklenburg

SPECIAL CERTIFICATES NAME CHANGE

Dynaphone, John Michael Willard, d/b/a - Order Granting Name Change from John Michael Willard
SC-617 (1-23-91)

Pay Com, Incorporated - Order Granting Name Change from Danny Alvin Poindexter, Certificate No. 388A
SC-626 (2-26-91)

SPECIAL CERTIFICATES AMENDED, REVOKED, CANCELLED OR CLOSED

Docket No.	Date	Company
SC-22, Sub 1	8-14-91	Central Communications
SC-25, Sub 1	3-1-91	BCS Communications, Inc., Richard Gillespie, d/b/a
SC-105, Sub 1	6-27-91	C & D Communications
SC-116, Sub 1	2-26-91	Capital Dominion Corporation
SC-141, Sub 1	4-19-91	Hi-Tech Auto - Dominick Matarese
SC-144, Sub 1	3-19-91	Silance Service Center
SC-146, Sub 1	2-19-91	Tarheel Triad Girl Scout Council, Inc.
SC-214, Sub 1	7-25-91	Danagail Telecommunications
SC-223, Sub 2	12-9-91	Ronald R. Stephens
SC-227, Sub 1	4-22-91	Villane, Inc.
SC-232, Sub 1	4-19-91	Park's Grocery, Marshall Parks, d/b/a
SC-237, Sub 1	8-14-91	Three Winks Grocery
SC-257, Sub 1	3-18-91	Propst Brothers Distributors, Inc.
SC-267, Sub 1	11-18-91	Anson Community College
SC-289, Sub 2	11-19-91	Network Communications
SC-297, Sub 1	8-14-91	Dwayne M. Whiting
SC-312, Sub 1	10-16-91	Gopal K. Pandey
SC-346, Sub 1	11-26-91	Joe Eblen/Biltmore Oil Company, Inc.
SC-347, Sub 1	8-14-91	Mr. Telephone, Inc.
SC-353, Sub 1	2-26-91	Thomas C. Duncan/Clyde's Quick Stop
SC-355, Sub 1	5-23-91	Kent Geer/Mini Mart Store
SC-388, Sub 2	5-23-91	Danny Alvin Poindexter
SC-394, Sub 1	11-18-91	Preferred Telephone Service, Inc.
SC-397, Sub 1	10-15-91	Tele-America Communication Corporation
SC-420, Sub 1	7-25-91	Edward F. Grant
SC-435, Sub 1	10-16-91	Call Control, Inc.
SC-437, Sub 1	11-5-91	Public Pay Phone, Inc.
SC-437, Sub 2	11-5-91	Public Pay Phone, Inc.

SC-447, Sub 1	4-16-91	HRH Enterprises
SC-448, Sub 1	3-5-91	Carolina Phone & Alarms, Inc.
SC-474, Sub 1	7-11-91	Four Corners Variety, Inc.
SC-493, Sub 1	6-25-91	Susan L. Goetze
SC-500, Sub 1	3-11-91	Hatcher Enterprises
SC-507, Sub 1	10-15-91	Institutional Energy Management, Inc.
SC-521, Sub 1	6-20-91	First Continental Communications, Inc.
SC-533, Sub 1	4-4-91	The Lake Norman Motel
SC-534, Sub 1	4-25-91	M & D Quick Stop
SC-541, Sub 1	4-4-91	London Communications, Inc.
SC-544, Sub 1	9-13-91	Flash Food Store
SC-558, Sub 1	10-15-91	Douglas J. Fish
SC-604, Sub 1	12-17-91	Fred Andrianse
SC-605, Sub 1	10-10-91	Northern Nash Senior High School
SC-611, Sub 1	4-5-91	Hon Ming Chan
SC-620, Sub 1	10-15-91	Eden Drug, Inc.
SC-621, Sub 1	10-15-91	Reidsville Pharmacy, Inc.
SC-625, Sub 1	4-19-91	Michael Warren
SC-645, Sub 1	10-15-91	Rockingham Center Pharmacy, Inc.
SC-653, Sub 1	11-18-91	Pisgah High School
SC-669, Sub 1	11-18-91	Charles Barbours and Richard Berry
SC-692, Sub 1	10-16-91	Northern Vance High School
SC-696, Sub 1	11-18-91	Fred T. Foard High School
SC-698, Sub 1	11-5-91	Edgcomb Metals Company
SC-701, Sub 1	11-18-91	Adams Products Company
SC-706, Sub 1	12-13-91	Ronald Ramsey

TARIFFS

Alltel Carolina, Heins, and Sandhill Telephone Companies - Order Allowing EAS Matrix Tariffs to Become Effective
P-118, Sub 64; P-26, Sub 105; P-53, Sub 60 (9-10-91)

ALLTEL Cellular Associates - Order Allowing Tariff to Offer Free Phones to go into Effect
P-149, Sub 12 (6-26-91)

ALLTEL Cellular Associates Order Allowing Tariff to Become Effective
P-149, Sub 13 (8-27-91)

AT&T Communications of the Southern States, Inc. - Order Allowing Intrastate Multiquest Tariffs to Become Effective
P-140, Sub 28 (8-28-91)

AT&T Communications of the Southern States, Inc. - Order Deferring Filing of Flow-Through or Offset
P-140, Sub 29 (4-10-91)

AT&T Communications of the Southern States, Inc. - Order Concerning Tariff to Revise Its Series 2000 Private Line Rates
P-140, Sub 29 (10-15-91)

AT&T Communications of the Southern States, Inc. - Order Suspending Tariff
P-140, Sub 32; P-100, Sub 72 (4-10-91)

Cellcom of Hickory - Order Suspending Tariff to Increase Roamer Charges
P-228, Sub 4 (4-17-91)

Citizens Telephone Company - Order Approving Tariff Filing for Authority to Adjust its Rates and Charges for Intrastate Telephone Service
P-12, Sub 89 (2-28-91)

GTE South and Southern Bell Telephone and Telegraph Company - Order Allowing Tariff to go into Effect to Establish Rates for ISDN PRI Arrangements for Northern Telecom (Commissioner Hughes dissents.)
P-55, Sub 949; P-19, Sub 238 (3-12-91)

General Telephone Company - Order Allowing Tariff to go into Effect to Consolidate Its Two Centrex Offerings (Commissioner Hughes voted "no".)
P-19, Sub 239 (3-20-91)

Metro Mobile CTS of Charlotte, Inc. - Order Suspending Tariff to Add New Rate Plans and Bundle Equipment and Service
P-155, Sub 15 (11-14-91)

Metro Mobile CTS of Charlotte, Inc. - Order Allowing Tariff to Add New Rate Plans and Bundle Equipment and Service
P-155, Sub 15 (12-10-91)

North Carolina RSA #15 Cellular Associates - Order Allowing Tariff to Offer Free Phones to go into Effect
P-225, Sub 2 (6-26-91)

Southern Bell Telephone and Telegraph Company Order Regarding SS7 Interconnections
P-55, Sub 925 (5-31-91)

Southern Bell Telephone and Telegraph Company - Order Allowing to Offer an Inward Toll Optional Calling Plan for IntraLATA Only 800 Service to go into Effect
P-55, Sub 943 (1-4-91)

Southern Bell Telephone and Telegraph Company - Order Allowing Integrated Service Digital Network Service Tariff for Wake County Government to go into Effect
P-55, Sub 946 (1-29-91)

Southern Bell Telephone and Telegraph Company Order Allowing Tariff for the University of North Carolina at Chapel Hill
P-55, Sub 950 (3-27-91)

Southern Bell Telephone and Telegraph Company - Order Suspending Tariff to Introduce SS7 Access Service for Interexchange Carriers
P-55, Sub 954 (5-22-91)

Southern Bell Telephone and Telegraph Company - Order Requiring Withholding of Calling Number
P-55, Sub 954 (6-27-91)

Southern Bell Telephone and Telegraph Company - Order Allowing Tariff Contract Service Arrangement for R. J. Reynolds Tobacco Company
P-55, Sub 959 (11-13-91)

Telephone Answering Service of Fayetteville, Inc. - Order Allowing Tariff to Establish Rates for Pre-recorded Greetings, Prompts, and Messages for its Paging Services
P-103, Sub 9 (4-3-91)

Telespectrum, Inc.; Raleigh-Durham MSA Limited Partnership; Centel Cellular Company of North Carolina; Centel Cellular Company of Hickory Limited Partnership; Centel Cellular Company of Hickory; N.C. RSA No. 15 North Sector Limited Partnership; Carolina RSA No. 6 Limited Partnership; and Carolina Telephone and Telegraph Company - Order Suspending Tariff
P-7, Sub 768; P-190, Sub 6; P-240, Sub 3; P-150, Sub 22; P-251, Sub 1; P-232, Sub 2; P-148, Sub 16; P-157, Sub 30 (11-18-91) Order Allowing Tariff (12-6-91)

Telespectrum, Inc.; Raleigh-Durham MSA Limited Partnership; Centel Cellular Company of North Carolina; Centel Cellular Company of Hickory of Hickory Limited Partnership; Centel Cellular Company of Hickory, and NC RSA No. 15 North Sector Limited Partnership - Order Allowing Tariffs
P-190, Sub 7; P-240, Sub 4; P-150, Sub 23; P-232, Sub 3; P-148, Sub 17; P-157, Sub 31 (11-18-91)

MISCELLANEOUS

Affinity Fund, Inc. - Order to Cease and Desist
P-233, Sub 1 (4-23-91)

Affinity Fund, Inc. - Order Approving Refund Plan
P-233, Sub 1 (7-17-91)

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C & L Utilities, Inc. - Order Allowing Withdrawal of Application to Transfer the Sewer Utility System Serving Serenity Point Condominiums, Pender County, to the Serenity Point Utilities Homeowners Association and Closing Docket
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Fox Run Water Company, Inc. - Order Denying Application for Transfer of Franchise for Providing Water Utility in Morristown, Jack's Landing, Mill Creek Landing, Timbuctu, Woodland Shores, and Creekside Shores Subdivisions, Warren County, and Timberline Shores Subdivision, Northampton County, to Moseley and Nash Company, Inc., d/b/a Fox Run Water Company, Inc., and for Approval of Rates
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Oyster Bay Utilities, Inc. - Order Allowing Withdrawal of Application and Closing Docket
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Carolina Water Service, Inc., of North Carolina - Order Revising Certificate to Furnish Water Utility Service in Cambridge Subdivision, Cabarrus County, and Approving Rates
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Heater Utilities, Inc. - Order Granting Authority to Provide Water Utility Service in Deerfield Subdivision, Johnston County, and Approving Rates
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Hickory Creek Developers, Inc. - Recommended Order Granting Water Utility Franchise to Furnish Water Utility Service in Hickory Creek Subdivision, Gaston County, and Approving Rates
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Hydraulics, Ltd. - Order Granting Authority to Provide Water Utility Service in Bexley Place Subdivision, Forsyth County, and Approving Rates
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Hydraulics, Ltd. - Order Modifying Order of December 28, 1990, for Certificate to Furnish Water Utility Service in River Run Subdivision, Randolph County, and Approving Rates
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Mid South Water Systems, Inc. - Order Granting Authority to Provide Water and Sewer Utility Service in The Landings Subdivision, Catawba County, and Requiring Refunds
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Mid South Water Systems, Inc. - Order Granting Franchise to Furnish Sewer Utility Service in Northbridge Marina, Iredell County, and Approving Rates
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Carolina Water Service, Inc., of North Carolina - Order on Complaint in Complaint of Grady Cook
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Carolina Water Service, Inc., of North Carolina - Recommended Order Requiring Further Investigation and Monitoring in Complaint of Sheree Croft and Mary L. Davis, Tanglewood South Subdivision, Cumberland County
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Carolina Water Service, Inc., of North Carolina - Recommended Order on Inspection and Test Results in Complaint of Sheree Croft and Mary L. Davis, Tanglewood South Subdivision, Cumberland County
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Carolina Water Service, Inc., of North Carolina - Order Dismissing Complaint Without Prejudice and Closing Docket in Complaint of Interlaken, Inc.
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Carolina Water Service, Inc., of North Carolina - Order Closing Docket in Complaint of Lester J. Carpenter
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Carolina Water Service, Inc., of North Carolina - Order Keeping Docket Open for Six Months in Complaint of Roland Pridgen
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Falls Utility Company - Recommended Order Regarding Amounts Due in Complaint of A. K. Parrish
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Falls, Ralph L. Waterworks - Order Keeping Docket Open for Six Months in Complaint of Mrs. Estelle Earnhardt and Other Residents of Oakley Park
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Fisher Utilities, Inc. - Order Closing Docket in Complaint of Steve Davidson
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Lakeview Mobile Home Park, David A. Elbaum, d/b/a - Order Allowing Public Staff Motion to Withdraw Complaint and Closing Docket
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Mid South Water Systems, Inc. Order Closing Docket in Complaint of Keith R. Carpenter
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Onslow County Board of Education - Order Finding no Jurisdiction to Hearing and Investigate in Complaint of Sentry Utilities, Inc.
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Scotsdale Water & Sewer, Inc. - Order Closing Docket in Complaint of Martin Gray
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Scotsdale Water & Sewer, Inc. - Recommended Order Denying and Dismissing Complaint of William C. Phillips
W-883, Sub 13 (9-26-91)

Surry Water Company - Order Keeping Docket Open for Six Months in Complaint of Josephine Plummer and Residents of Snowhill Subdivision
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Mid South Water Systems, Inc. - Order Declaring Temporary Utility Status, Allowing Extension of Time, and Requiring Compliance with Order of June 28, 1991
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Bethlehem Utilities, Inc. - Order Authorizing Discontinuation of Water Utility Systems Serving Pinecrest Park, Lakemont Park, and Fairfield Acres Subdivision, Alexander County
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Bethlehem Utilities, Inc. - Order Authorizing Discontinuation of Service of Water Utility Systems Serving Lakemont Park and Fairfield Acres Subdivisions, Alexander County
W-259, Sub 8 (4-24-91)

Carolina Water Service, Inc., of North Carolina - Order Authorizing Discontinuation of Service for Authority to Abandon the Water Utility System Serving Rolling Hills Estates Subdivision, Forsyth County
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Castor Court Water Company, Inc., of North Carolina - Order Authorizing Discontinuance of Service for Authority to Abandon the Water Utility System Serving Castor Court Subdivision, Cabarrus County
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Huffman, H. C. Water Systems, Inc. - Order Authorizing Discontinuance of Service for Authority to Abandon the Water Utility System Serving Highlander Hills Subdivision, Alexander County
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Mid South Water Systems, Inc. - Order Authorizing Discontinuation of Service for Authority to Abandon the Water Utility System Serving Harbor Town Subdivision, Alexander County
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Mobile Heights Water System, Gerald Barfield, d/b/a - Order Granting Discontinuance of Water Service in Mobile Heights Subdivision, Lenoir County, and to Allow Service to be Provided by North Lenoir Water Corporation (Owner Exempt from Regulation)
W-960, Sub 1 (1-11-91)

Piedmont Construction and Water Company - Order Allowing Discontinuance of Service for Water Utility Service in Random Woods Subdivision, Catawba County, and Cancelling Franchise
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Silver Maple Mobile Estates - Order Authorizing Discontinuation of Service to Lots 30, 31, and 32 in Paradise Estates Subdivision, Cabarrus County
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Hidden Valley Campground Estates, Inc. - Order Declaring Emergency Operator for Water Utility Service in Hidden Valley Campground Estates Subdivision, Henderson County and Approving Rates
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Mid South Water Systems, Inc. - Order Authorizing Emergency Sewer Service in Britley Subdivision, Cabarrus
W-720, Sub 108 (4-16-91)

Mid South Water Systems, Inc. - Order Authorizing Emergency Sewer Service to Four Additional Lots in Britley Subdivision
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Pied Piper Resort, Inc. - Recommended Order Permanently Prohibiting Reconnection of Campground Property for Appointment of Carolina Water Service, Inc., of North Carolina as Emergency Operator to Furnish Water Service in Pied Piper Subdivision
W-893, Sub 1 (8-1-91)

Sass, C. C. Company - Preliming Injunction and Emergency Operating Authority by Consent; Operating a Sewage Treatment Facility Serving Commercial Property in Cape Carteret
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Wastewater Services, Inc. Order Approving Name Change to HydroLogic, Inc.
W-988, Sub 1 (1-31-91)

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4 Seasons Mohovilla Utilities, G. P. McConiga, d/b/a - Interlocutory Order Approving Interim Rates to Furnish Water Utility Service in 4 Seasons Mohovilla Mobile Home Park, Lenoir County
W-1002 (9-24-91)

Alpha Utilities, Inc. - Order Granting Rate Increase for Providing Water Utility Service in Oak Ridge Subdivision, Johnston County, and Requiring Customer Notice
W-862, Sub 9 (8-8-91)

BRTR, Inc. - Order Lifting Moratorium to Increase Rates for Water Utility Service in Fox Ridge and Woods of Fox Ridge Subdivision, Henderson County
W-762, Sub 3 (11-19-91)

BRTR, Inc. - Order Dismissing Proceedings and Closing Dockets for Increase in Rates and Tariff Revision
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Bogue Banks Water and Sewer Company - Order Approving Schedule of Rates to Provide Water Utility Service in Emerald Isle, Indian Beach, and Salter Path;, Carteret County, and Approval of Rates
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Brookwood Water Corporation - Interlocutory Order Granting Interim Rates for Providing Water Utility Service in All Its Service Areas in North Carolina
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Brookwood Water Corporation - Recommended Order Granting Partial Rate Increase for Providing Water Utility Service in All Its Service Areas in North Carolina
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Brown, E. S. - Order Granting Interim Rate Increase for Providing Water Utility Service in Butler Mountain Estates Subdivision, Buncombe County
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Brown, E. S. - Interlocutory Order Granting Rate Increase for Water Utility Service in Butler Mountain Estates Subdivision, Buncombe County, and by James R. Jackson for Authority to Transfer the Franchise to Provide Service from E. S. Brown
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Carolina Trace Corporation - Recommended Order Approving Rates for Providing Water and Sewer Utility Service in Carolina Trace Subdivision, Lee County
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Carolina Water Service, Inc., of North Carolina - Order Approving Rates for Providing Water and Sewer Utility Service in Its Service Areas in North Carolina
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Clearwater Utilities, Inc. - Recommended Order Approving Increase in Rates for Providing Water Utility Service in All Its Service Areas in North Carolina
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Cowan Valley Water System - Order Approving Rates and Service Regulations
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Dogwood Knolls Water Company, R. Wiley Smith, d/b/a - Order Granting Rate Increase for Providing Water Utility Service in Dogwood Knolls Subdivision, Buncombe County, Cancelling Hearing, Requiring Improvements, and Requiring Public Notice
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Eagle Heights Utility Company - Recommended Order Granting Rate Increase for Providing Water Utility Service in Eagle Heights Subdivision, Buncombe County
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Emerald Plantation Utility Company - Recommended Order Granting Rate Increase for Sewer Utility Service in Emerald Plantation Subdivision and Emerald Plaza Shopping Center, Carteret County
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Farm Water Works - Recommended Order Granting Rate Increase for Providing Water Utility Service in Winding Creek Farm Subdivision, Lee County
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Fleetwood Falls, Inc. - Interlocutory Order Granting Partial Rate Increase for Authority to Increase Rates for Water Utility Service in Fleetwood Falls Subdivision, Ashe County
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Foxhall Village Utilities - Recommended Order Approving Rate Increase for Water and Sewer Utility Service in Foxhall Village Subdivision, Wake County
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Franklinville Waste Treatment Company - Order Approving Rate Increase for Providing Sewer Utility Service in All Its Service Areas in Randolph County, and Requiring Public Notice
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Glynnwood Mobile Home Park - Recommended Order Approving Rate Increase for Providing Water Utility Service in Glynnwood Mobile Home Park, New Hanover County
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Goose Creek Utility Company - Order Amending Rate Schedule
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Goss Utility Company - Recommended Order Granting Rate Increase for Providing Water Utility Service in All Its Service Areas in Chatham, Durham, and Person Counties, and Approving Interim Rates
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Green Spring Valley Mobile Estates - Order Approving Rate Increase for Providing Water and Sewer Utility Service in Green Spring Valley Mobile Estates Subdivision, Wake County
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Gresham's Lake Utility Company, Inc. - Recommended Order Approving Partial Rate Increase for Water and Sewer Utility Service in Gresham's Lake Industrial Park, Wake County
W-633, Sub 4 (1-3-91) Order Adopting Recommended Order (1-8-91)

Heater Utilities, Inc. - Order Granting Interim Rate Relief for Providing Sewer Utility Service in Barclay Downs, Beachwood, Briarwood Farms, Hawthorne, Mallard Crossing, and Wildwood Green Subdivisions, Wake County, and Rescheduling Hearing
W-274, Sub 62 (6-27-91)

Heater Utilities, Inc. - Recommended Order Granting Partial Rate Increase for Sewer Utility Service in Barclay Downs, Beachwood, Briarwood Farms, Hawthorne, Mallard Crossing and Wildwood Green Subdivisions, Wake County
W-274, Sub 62 (12-3-91)

Heater Utilities, Inc. - Order Granting Interim Rates Relief for Providing Sewer Utility Service in Windsor Oaks Subdivision, Wake County, and Rescheduling Hearing
W-274, Sub 63 (6-27-91)

Heater Utilities, Inc. - Recommended Order Granting Partial Rate Increase for Sewer Utility Service in Windsor Oak Subdivision, Wake County
W-274, Sub 63 (11-8-91)

Holly Hills Water, Donald Miller, d/b/a - Order Approving Rate Increase for Providing Water Utility Service in Holly Hills Estates Subdivision, Jackson County
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Hyland Hills Water Company, Robert A. Pipkin, d/b/a - Recommended Order Granting Partial Rate Increase for Providing Water Utility Service in Hyland Hills Subdivision, Moore County
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Jones Dairy Farm Utility, Inc. - Recommended Order Granting Rate Increase for Providing Sewer Utility Service in Jones Dairy Farm Subdivision, Wake County
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Knob Creek Properties, Inc. - Recommended Order Approving Increase in Rates for Providing Water Utility Service in All Its Service Areas in Translyvania County
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W-641, Sub 2 (1-7-91)

Mercer Environmental Corporation - Order Approving Rates for Water Utility Service in All of Its Service Areas which are Served by Water Purchased from Onslow County
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Mobile Hill Estates Water System (Scotsdale Water and Sewer, Inc., Emergency Operator) - Order Granting Partial Rate Increase for Water Utility Service in Mobile Hill Estates Subdivision, Wake County
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Nags Head Village Service Company - Recommended Order Approving Rate Increase for Providing Sewer Utility Service in Nags Head Village Subdivision, Dare County, and Setting Rate Base
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North Topsail Water & Sewer, Inc. - Interlocutory Order Granting Interim Rates for Sewer Utility Service in Its Service Area, Onslow County
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Rock Barn Properties, Inc. - Recommended Order Granting Partial Rate Increase for Providing Water and Sewer Utility Service in Rock Barn Golf Club and Subdivision, Catawba County, and for a Certificate of Public Convenience and Necessity to Provide Sewer Service in Rock Barn Subdivision
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Sapphire Lakes Utility Company - Recommended Order Approving Rate Increase for Providing Water and Sewer Service in Sapphire Lakes Subdivision, Transylvania County
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Scotsdale Water and Sewer, Inc. - Supplemental Order Amending Schedule of Rates for Providing Water Utility Service in All Its Service Areas in North Carolina
W-883, Sub 12 (1-11-91)

Skyland Drive Water Association, Jan Black, d/b/a - Order Approving Rate Increase for Providing Water Utility Service in Skyland Drive Subdivision, Gaston County
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South Mountain Water Works, Keith and Power Hildebran, d/b/a - Recommended Order Approving Rates for Providing Water Utility Service in Rollins Park Subdivision, Burke County
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TPG Utilities, Inc. - Recommended Order Approving Rate Increase for Providing Water Utility Service to Turkey Pen Gap Subdivision, Transylvania County
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Transylvania Utility Company - Recommended Order Granting Partial Rate Increase for Providing Water and Sewer Service in Connestee Falls, Transylvania County
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Viking Utilities Corporation, Inc. - Recommended Order Granting Rate Increase for Sewer Utility Service in Hunter's Creek Subdivision, Onslow County, and Approving Interim Rates
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Alpha Utilities, Inc. - Order Granting Transfer of Franchise for Providing Water Utility Service in Stoney Brook Estates Subdivision, Johnston County, from Edith Bizzell, d/b/a Stoney Brook Estates Water System, and Approving Rates
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Brookwood Water Corporation - Interlocutory Order Approving Transfer of Franchise to Provide Water Utility Service in Tunbridge Subdivision, Cumberland County, from Cumberland Water Company and Rates and Scheduling Hearing
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Brown, E. S. - Recommended Order Allowing Transfer of Water System and Franchise to Butler Water, Inc.
W-1006; W-732, Sub 2 (9-11-91)

Butler Water, Inc. - Recommended Order Approving to Transfer 100% of the Stock of Butler Water, Inc., and the Franchise to Provide Water Utility Service in Butler Mountain Estates Suddivision, Buncombe County, to Robin E. Dunn, and Approving Rates
W-1006, Sub 2 (12-31-91)

CWS Systems, Inc. - Order Denying Motion for Authority to Acquire the Franchises and Assets of the Water Utility Systems Serving all the Subdivisions Located in Durham, Franklin, Nash, and Wake Counties, from Clearwater Utilities, Inc., and Approving Rates (Commissioner Tate dissents.)
W-778, Sub 8 (8-2-91) Errata Order (8-9-91)

CWS Systems, Inc. - Order Approving Transfer to Acquire the Franchise and Assets of the Water Utility Systems, Serving All the Subdivisions located in Durham, Franklin, Nash, and Wake Counties, from Clearwater Utilities, Inc., and for Approval of Rates (Commissioner Wright did not participate in this decision.)
W-778, Sub 8 (8-23-91)

Carolina Lakes Corporation - Recommended Order Approving Transfer to Provide Water and Sewer Utility Service in Carolina Lakes Subdivision, Harnett County, to Southwest Water and Sewer District of Harnett County (Owner Exempt from Regulation)
W-879, Sub 1 (1-18-91) Order Adopting Recommended Order as Final Order (1-18-91)

Carolina Water Service, Inc., of North Carolina - Order Granting Transfer to Provide Water Utility Service in Grandview Subdivision, Forsyth County, from T-Square Water Company, Inc., and Order Requiring Response as to Operation Before Approval
W-354, Sub 91 (1-14-91)

Carolina Water Service, Inc., of North Carolina - Order Approving Transfer of Water Utility System Serving Mt. Carmel/Lee's Ridge Subdivision, Buncombe County, to the Asheville-Buncombe Water Authority (Owner Exempt from Regulation), Requiring Customer Notice, and Requiring Additional Information of Capital Gain or Loss
W-354, Sub 100 (3-6-91)

Carolina Water Service, Inc., of North Carolina - Recommended Order Approving Transfer to Operate Temporarily and to Acquire the Franchise and Assets of the Water System Serving the Providence West Subdivision Located in Mecklenburg County
W-354, Sub 101 (12-4-91)

Fox Run Water Company, Inc. - Order Granting Transfer of the Franchise for Providing Water Utility Service in Morristown, Jack's Landing, Mill Creek Landing, Timbuctu, Woodland Shores, and Creekside Shores Subdivisions, Warren County, and Timberline Shores Subdivision, Northampton County, to Moseley and Nash Company, Inc., d/b/a Fox Run Water Company, Inc., and Approving Rates
W-959, Sub 2 (9-18-91)

Hendrix Barnhill Company, Inc. - Recommended Order Approving Transfer of Ownership of the Water Utility System Serving Pleasant Ridge Subdivision, Pitt County, to the Town of Ayden (Owner Exempt from Regulation)
W-658, Sub 1 (3-5-91) Order Adopting Recommended Order (3-11-91)

Hoopers Valley Water Company, Herschel Yarber, d/b/a - Order Denying Application to Transfer the Water Utility Franchise Serving Hoopers Valley Estates Subdivision, Henderson County, to Hoopers Valley Water Company, and for Approval of Rates
W-794, Sub 2 (4-29-91)

Huey, Wade and Louise - Order Denying Application to Transfer the Franchise to Provide Water Utility Service in Rolling Acres Subdivision, Buncombe County, to HydroLogic, Inc., and for Approval of Rates
W-988 (4-29-91)

Hydraulics, Ltd. - Recommended Order Granting Transfer of Franchise to Provide Water Utility Service in Sprinkley Subdivision, Caswell County, from Millner Water Systems and Partial Rate Increase
W-218, Sub 77 (11-27-91)

HydroLogic, Inc. - Approving Transfer of Franchise to Provide Water Utility Service in Skyview Park Subdivision, Gaston County, from Skyview Water System, Inc., and Approving Rates
W-988, Sub 3 (11-13-91)

Hyland Hills Water Company, Robert Pipkin, d/b/a - Order Approving Transfer of Water Utility System Serving Hyland Hills Subdivision, Moore County, to Moore Water and Sewer Authority (Owner Exempt from Regulation)
W-920, Sub 3 (12-30-91)

Intracoastal Utilities, Inc. - Recommended Order Approving Transfer of Franchise for Providing Sewer Utility Service in Brick Landing Plantation Subdivision, Brunswick County, from Brick Landing Utility Corporation
W-986 (11-26-91)

LaGrange Waterworks Corporation - Recommended Order Approving Transfer of Ownership of Certain Water Utility Systems (Stewart's Creek, Glen Reilly, Valley Forge, North Shores, Morganton Place, Deerwood, Family Lodge, Murray Fork, LaGrange, and Kindellwood/The Oaks) to the Fayetteville Public Works Commission (Owner Exempt from Regulation)
W-200, Sub 23 (2-14-91)

Mid South Water Systems, Inc. - Order Approving Transfer for the Water and Sewer Utility Systems Serving Autumn Chase Subdivision, Cabarrus County, to the City of Kannapolis (Owner Exempt from Regulation)
W-720, Sub 112 (7-8-91)

Mid South Water Systems, Inc. - Order Granting Transfer of Franchise to Provide Water Utility Service in Fox Ridge, Woods at Fox Ridge, and Fountain Trace Subdivisions, Henderson County, from BRTR, Inc., and Approving Rates
W-720, Sub 115 (12-10-91)

Montclair Water Company, Inc. - Recommended Order Approving Transfer of Ownership of Its Water and Sewer Utility Systems, Cumberland County, to the Fayetteville Public Works Commission (Owner Exempt from Regulation)
W-173, Sub 19 (2-14-91)

Mulkey Homesites Water System - Order Approving Transfer of Franchise to Provide Water Utility Service in Mulkey Homesites Subdivision, Cherokee County, to the Town of Murphy (owner exempt from regulation)
W-818, Sub 1 (4-3-91)

Norwood Beach Water System - Order Granting Transfer to Provide Water Utility Service in Tranquil Bay Subdivision, Stanly County, from H & A Water Service, Inc., and Approving Rates
W-498, Sub 7 (12-23-91)

P & H Water Company, Inc. - Order Approving Transfer of Ownership of Its Water Utility System, Cumberland County, to the Fayetteville Public Works Commission (Owner Exempt from Regulation)
W-257, Sub 3 (4-10-91)

Pen Properties, Inc. - Order Approving Transfer of Ownership of the Water Utility Systems Serving Quail Haven and Quail Point Subdivisions, Onslow County, to Onslow County (Owner Exempt from Regulation)
W-586, Sub 1 (7-31-91)

Piedmont Construction and Water Company, Inc. - Order Granting Transfer to Provide Water Utility Service in Pleasant Gardens Subdivision, Alexander County, from Pleasant Gardens Water Department, and Approving Rates
W-262, Sub 39 (9-18-19)

Piedmont Construction and Water Company, Inc. - Order Approving Transfer for Providing Water Utility Service in Jan Joy Subdivision, Iredell County, to the City of Statesville (Owner Exempt from Regulation)
W-262, Sub 40 (6-28-91)

ST Utility Company, Sea Trail Corporation, d/b/a - Recommended Order Approving Transfer of Franchise for Providing Sewer Utility Service in Oyster Bay Plantation Subdivision, Brunswick County, from Oyster Bay Utilities, Inc.
W-984 (11-26-91)

TET Utilities, Inc. - Order Approving Transfer for Providing Sewer Utility Service in Dunescape Villas Condominiums, Cateret County, to Dunescape Villas Condominiums Owners Association (Owner Exempt from Regulation), and Cancelling Franchise
W-759, Sub 4 (6-12-91)

TARIFFS

Associated Utilities, Inc. - Order Approving Tariff Revision
W-303, Sub 9 (1-29-91)

Brookwood Water Corporation - Order Granting Approval of the Net Present Value Gross Up Method
W-177, Sub 33 (6-28-19)

CWS Systems, Inc. - Order Amending Schedule of Rates
W-778, Sub 4 (2-1-91)

CWS Systems, Inc. - Order Approving Tariff Revision
W-778, Sub 7 (2-20-91)

Heater Utilities, Inc. - Order Amending Tariff to Furnish Water Utility Service in Cary Oaks Subdivision, Wake County, and for Approval of Rates
W-274, Sub 66 (8-2-91)

Meyer, C. Cliff, Inc. - Order Approving Tariff Revision for Water Utility Service in Charmeldee Subdivision, Buncombe County
W-919, Sub 1 (12-20-91)

SRME Water System - Order Approving Tariff Amendment Allowing Rate Increase for Providing Water Utility Service in Spring Road Mobile Estates Subdivision, Beaufort County
W-733, Sub 4 (9-5-91)

Scientific Water Sewage, Inc. - Order Approving Tariff Revision to Increase Rates for Water Utility Service in All Its Service Areas Served by Water Purchased from Onslow County
W-176, Sub 23 (9-18-91)

Smith, R. Wiley - Order Approving Tariff Revision
W-792, Sub 3 (1-22-91)

Vila Pump Company - Order Approving Tariff Revision for Water Utility Service in Skyline Estates Subdivision, Lee County
W-945, Sub 1 (10-8-91)

West Wilson Water Corporation - Order Approving Tariff Revision for Water Utility Service for White Oak Subdivision, Wilson County, Due to VOC Testing Expense
W-781, Sub 12 (3-25-91)

West Wilson Water Corporation - Order Approving Tariff Revision for Water Service in White Oak Subdivision, Wilson County
W-781, Sub 13 (5-23-91)

TEMPORARY OPERATING AUTHORITY

Empire Utilities, Inc. - Order Granting Temporary Operating Authority to Provide Water Utility Service in Mobile Hill Estates Subdivision, Wake County, from First Investments Mortgage Advisors, Inc., and Requiring Improvements
W-987 (5-8-91)

Hidden Creek Utility Company, c/o Rayco Utility Inc. - Order Granting Temporary Operating Authority to Provide Sewer Utility Service to Hidden Creek Subdivision, Davie County, and Requiring Customer Notice
W-982 (1-18-91)

Hillview and Oakview Trailer Courts, Raymond Everhardt, d/b/a - Order Granting Temporary Operating Authority to Furnish Water Utility Service in Hillview and Oakview Trailer Courts, Rowan County, Approving Interim Rates, Setting Hearing, and Requiring Public Notice
W-1008 (12-19-91)

Johnson and Perry Company - Order Granting Temporary Operating Authority to Furnish Water and Sewer Utility Service in Creekside Townhomes, Brunswick County, Approving Interim Rates, Setting Hearings, and Requiring Public Notice
W-998 (7-31-91) Errata Order (8-2-91)

Love Point, Inc. - Order Granting Temporary Operating Authority to Provide Water Utility Service in Love Point Subdivision, Catawba County, Approving Interim Rates, Setting Hearing, and Requiring Public Notice
W-993 (6-26-91)

Love Point, Inc. - Recommended Order Continuing Temporary Operating Authority, Continuing Interim Rates and Requiring Transfer of System or Bond to Furnish Water Utility Service in Love Point Subdivision, Catawba County
W-993 (10-10-91)

Mountain Point Utilities, Inc., c/o Rayco Utility Inc. - Order Granting Temporary Operating Authority to Provide Water Utility Service to Mountain Point Subdivision, Mecklenburg County, and Requiring Customer Notice
W-989 (1-18-91)

Rock Barn Properties, Inc. - Order Granting Temporary Operating Authority to Furnish Sewer Utility Service in Rock Barn Subdivision, Catawba County, Approving Interim Rates, and Scheduling Hearing
W-747, Sub 2 (7-31-91)

ST Utility Company, Sea Trail Corporation, d/b/a - Order Granting Temporary Authority to Transfer the Franchise for Providing Sewer Utility Service in Oyster Bay Plantation Subdivision, Brunswick County, from Oyster Bay Utilities, Inc., and Interim Rates
W-984 (3-12-91)

West Johnston Water Company, West Johnston Mobile Acres, d/b/a - Order Granting Temporary Operating Authority to Furnish Water Utility Service in West Johnston Mobile Acres, Johnston County, Approving Interim Rates, Setting Hearing, and Requiring Public Notice
W-1003 (8-27-91)

West Johnston Water Company, West Johnston Mobile Acres, d/b/a - Interlocutory Order Extending Temporary Operating Authority to Furnish Water Utility Service in West Johnston Mobile Acres, Johnston County
W-1003 (11-12-91)

Willowbrook Utility Company, Inc., c/o Rayco Utility Inc. - Order Granting Temporary Operating Authority to Provide Water and Sewer Utility Service to Willowbrook Subdivision, Mecklenburg County, and Requiring Customer Notice
W-981 (1-18-91)

MISCELLANEOUS

Brookwood Water Corporation Order Addressing CIAC Issue
W-177, Sub 32 (7-19-19)

Carolina Water Service, Inc., of North Carolina - Order Dismissing Petition for a Ruling Regarding Issues Related to the Provision of Water Service to the Wolf Laurel Development Area, Madison and Yancey Counties
W-354, Sub 99 (12-5-91)

Carolina Water Service, Inc., of North Carolina - Order Addressing CIAC Issue, to Operating Temporarily and to Acquire the Franchise and Assets of the Water System Serving the Providence West Subdivision Located, Mecklenburg County
W-354, Sub 101 (7-19-91)

Carolina Water Service, Inc., of North Carolina - Order Approving Amended CIAC Gross Up Factors
W-354, Sub 107 (9-18-91)

Carolina Water Service, Inc., of North Carolina - Order No Longer Requiring Monthly Report
W-354, Sub 81 (10-22-91)

ORDERS AND DECISIONS LISTED

Carolina Water Service, Inc., of North Carolina; Carolina Water Systems, Inc. - Order Approving Settlement Agreement (cross-referenced)
W-354, Sub 91; W-778, Sub 6 (5-8-91)

Carolina Water Systems, Inc.; Carolina Water Service, Inc., of North Carolina - Order Approving Settlement Agreement (cross-referenced)
W-778, Sub 6; W-354, Sub 91 (5-8-91)

Cowan Valley Water System - Notice and Order Approving $120 Assessment for Cowan Valley Homeowners Association, Emergency Operator
W-829, Sub 3 (3-28-91)

LaGrange Water Works Corporation - Order Restricting Water Use and Requiring Public Notice
W-200, Sub 24 (6-14-91) Order Modifying Order of June 14, 1991, Restricting Water Use (7-12-91)

Mid South Water Systems, Inc. - Order Authorizing Sewer Service to Remaining Nine Lots in Britley Subdivision Phase I
W-720, Sub 96; W-720, Sub 108 (10-24-91)

Sass, C. C. Company - Order Instituting Show Cause Proceeding, Scheduling Show Cause Hearing, and Issuing Restraining Order
W-1001 (7-23-91)

Waverly Mills, Inc. - Order Granting Suspension of a Water and Sewer Utility Franchise in East Laurinburg, Scotland County, for the Term of One Year
W-734, Sub 2 (9-6-91)