Re Carolina Power & Light Company

Docket No. E-2, Sub 526
87 PUR4th 64

North Carolina Utilities Commission
August 27, 1987

APPLICATION for authority to adjust and increase electric rates and charges; granted as modified.

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1. RATES, § 120.1 — Test period — Electric rate design.

[N.C.] A test period ending approximately 16 months before the date of decision was employed in an electric rate case. p. 73.

2. EXPENSES, § 122 — Electric utilities — Capacity costs — Power sales contracts.

[N.C.] An electric utility's contracts to sell certain percentages of various power plants to the North Carolina Eastern Municipal Power Agency were found reasonable and prudent because the contracts had reduced the cost of electricity to the utility's retail customers and costs associated with the contracts were allowed in rates. p. 75.

3. EXPENSES, § 122 — Electric utilities — Capacity purchases.

[N.C.] Regarding the appropriate treatment to be given various components of the cost of power bought back by an electric utility from the North Carolina Eastern Municipal Power Agency, it was found appropriate to use estimated 1987 costs because such costs were representative of the ongoing costs that the utility was actually experiencing; the use of 1987 costs was also found appropriate to reflect the most current cost possible in the initial calculation of adjusted purchased capacity and nonfuel energy costs. p. 77.

4. EXPENSES, § 122 — Electric utilities — Capacity purchases — Test year matching concept.

[N.C.] The use of an electric utility's 1987 estimated costs, a period beyond the end of the test year, for the cost of purchased power, was found not to violate the test-year matching concept, because purchased capacity and nonfuel energy cost rates are independent of and do not rely on the measure of test-year service, but more importantly, the combination of 1987 cost rates and 1987-1988 buyback percentages was not an inappropriate matching because those items were independent of each other. p. 78.

5. EXPENSES, § 122 — Electric utilities — Capacity purchases — Tax component.

[N.C.] The commission concluded that the treatment of the income tax components within the electric utility's purchased capacity capital cost calculation, which incorporated tax rates of 40% for 1987 and 34% for 1988, were reflective of the terms in the power purchase contracts and the ongoing costs of purchased capacity under those terms. p. 80.

6. EXPENSES, § 122 — Electric utilities — Capacity purchases — Capital cost.

[N.C.] The capital cost of electric capacity purchases related to the Mayo electric generating plant and the Shearon Harris nuclear power plant, was assumed, for rate-making purposes, to be equal to the rate of return on common equity. p. 81.

7. EXPENSES, § 122 — Electric utilities — Capacity purchases — Levelization.

[N.C.] The levelization of purchased capacity costs was found to provide significant benefits to the electric utility's ratepayers, and was adopted, because levelization would compensate for the known decreases in capacity purchases in the coming years and protect ratepayers from overpaying while protecting and preventing the utility from undercollecting the costs being levelized. p. 81.

8. EXPENSES, § 122 — Electric utilities — Capacity purchases — Deferred amounts.

[N.C.] The difference between the levelized cost of purchased electric capacity and the actual purchased capacity payments was placed in a deferred account. p. 84.

9. VALUATION, § 25 — Rate base determination date — Nuclear plant phase-in.

[N.C.] An electric utility was authorized to include in rate base 50% of costs associated with the newly completed Shearon Harris nuclear power plant unit 1, and to recover 50% of the related depreciation and taxes associated with the plant in its operating expenses; the remaining 50% of costs for the Harris plant would be deferred and would accrue carrying costs, as consistent with the prior commission order in Docket No. E-2, Sub 511. p. 87.

10. APPORTIONMENT, § 23 — Expenses — Electric service— Summer-winter peak and average method.

[N.C.] For electric rate-making purposes, all jurisdictional cost allocations and allocations of fully distributed costs among customer classes were performed on the basis of the "summerwinter peak and average method," including the "minimum system technique." p. 89.

11. APPORTIONMENT, § 23 — Expenses — Electric service — Peak and average method — Twelve coincident peak method.

[N.C.] The summer-winter peak-and-average cost allocation method was found the most appropriate method for making jurisdictional cost allocations and for making fully distributed cost allocations between customer classes of an electric utility; the commission was not convinced that the current rate proceeding was the appropriate forum to change cost allocation methodologies to the twelve coincident peak method. p. 89.

12. APPORTIONMENT, § 11 — Expenses — Electric service — Distribution costs — Minimum system technique — System connection.

[N.C.] The "minimum system technique" is a method for allocating a portion of distribution plant of an electric utility between customer classes, and derives the cost of distribution plant as if all components of such plant are "minimum" size, which means the minimum size needed to connect each customer to the system regardless of the amount of kilowatt-hour used; the commission found it inappropriate to discontinue the use of this system. p. 90.

13. ELECTRICITY, § 4 — Generating plants — Nuclear capacity factors — Normalization.

[N.C.] Adjustments were made to the system nuclear capacity factors experienced by an electric utility during recent 12-month periods, based upon Commission Rule R8-55(c)(1), which provides for a method of normalization of nuclear capacity factors based on an equally weighted average of each nuclear unit's actual lifetime operating experience and the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council's Equipment Availability Report. p. 93.

14. ELECTRICITY, § 4 — Generating plants — Efficiency — Capacity factors.

[N.C.] In an electric rate case, the commission adopted normalized capacity factors for the following generating plants: Brunswick unit 1, 54.375%; Brunswick unit 2, 51.61%; Robinson unit 2, 63.46%; and Harris unit 1, 60.70%. p. 93.

15. VALUATION, § 299.1 — Working capital — Lead-lag study — Federal income tax rate.

[N.C.] When calculating the cash working capital for an electric utility, a per-books lead-lag study using the 46% federal income tax rate was found to be the appropriate method. p. 101.

16. VALUATION, § 192.1 — Accumulated deferred income taxes — Cost allocation method.

[N.C.] Accumulated deferred income taxes of an electric utility were adjusted in order to reflect the commission's position on the adjusted summer-winter peak and average cost allocation method, to reflect the utility's sale of assets to a municipal power agency, and to reflect changes in tax rates due to the Tax Reform Act of 1986. p. 103.

17. EXPENSES, § 48 — Treatment of particular expenses — Dues — Edison Electric Institute.

[N.C.] Reductions were made in the operating and maintenance expenses of an electric utility in order to disallow 40% of dues paid to the Edison Electric Institute and to disallow 50% of the payments made to EEI's Media Communication Fund. p. 108.

18. EXPENSES, § 114 — Income taxes — Tax Reform Act — Blended rate.

[N.C.] A level of federal income taxes calculated at a blended marginal rate of 40% was approved for electric rate-making purposes, following passage of the Tax Reform Act of 1986. p. 110.

19. EXPENSES, § 114 — Income taxes — Tax Reform Act.

[N.C.] An electric utility's reasonable and appropriate level of federal income tax (FIT) expense was based on the use of a 40% blended rate, but a refund with interest was ordered of the deferred account established in an earlier proceeding which tracked the difference in revenues billed under rates reflecting a 46% FIT rate and revenues that would have been collected if rates had been based upon a 40% FIT rate, and a second deferred account was established, which was to be used to accrue the difference between revenues billed under approved rates reflecting a 40% FIT rate as revenues that would have been billed if rates had been determined based upon a 34% FIT rate. p. 110.

20. EXPENSES, § 35 — Capital cost amortization — Abandoned nuclear plant — Expense sharing.

[N.C.] The commission made a liberal interpretation of the operating expense element of rate making so as to include abandonment losses from three nuclear generating plants, which was found to be a necessary interpretation in order to promote an equitable sharing of the loss between the electric ratepayers and the utility stockholders. p. 114.

21. RETURN, § 26.1 — Capital structure — Reasonableness.

[N.C.] Capital structure for an electric utility was set for rate-making purposes at the following portions: long-term debt, 48.5%; preferred equity, 8.5%; common equity, 43%. p. 117.

22. RETURN, § 26.1 — Capital structure — Normalization.

[N.C.] The fact that an electric utility's actual equity capitalization ratio had recently fluctuated generally above the requested level of 43% supported the use of the utility's offered pro forma or normalized capital structure estimated by adjusting the July 1986 actual capital structure for changes anticipated to occur through March 1987. p. 117.

23. RETURN, § 26.4 — Common equity capital — Electric utility.

[N.C.] A rate of return on common equity of 12.63% was approved for an electric utility. p. 122.

24. RETURN, § 87 — Reasonableness — Electric utility.

[N.C.] An overall rate of return on net investment of 10.45% was approved for an electric utility. p. 122.

25. RATES, § 339 — Electric rate design — Customer classes — Class rates of return — Equality.

[N.C.] Retail electric rates were set on the basis of a movement toward equal rates of return for customer classes, in light of state law, N.C.Gen.Stats. § 62-140, which prohibits rates that provide any "unreasonable preference or advantage of any person." p. 126.

26. RATES, § 339 — Electric rate design — Customer classes — Class rates of return — Equality.

[N.C.] Electric rates for the large general service class were increased by 0.9 times the percentage increase applied to the residential and small general service classes; rates for the sports field lighting class were increased by 1.1 times the percentage increase applied to the residential and small general service classes; such adjustments were made in conjunction with the commission's policy to move toward equal rates of return for customer classes. p. 126.

27. RATES, § 321 — Electric rate design — Unreasonable preference — Adjustments.

[N.C.] When determining rates for an electric utility, it is prohibited by statute to provide any unreasonable preference or differential, although it is unrealistic to expect to design rates that will produce exactly equal rates of return over time, because demand and energy usage characteristics vary from time to time, and they must be evaluated over an extended period of time in order to determine normal variations in rates of return: rates for the large general service class were ordered increased by 0.9 times the percentage increase applied to the residential and small general service classes; rates for the sports field lighting class were ordered increased by 1.1 times the percentage increase applied to the residential and small general service classes; and rates for other lighting classes were ordered maintained at current levels. p. 126.

28. RATES, § 339 — Electric rate design — Customer classes — Large general service.

[N.C.] The large general service electric rate schedule was changed from a single billing block to three billing blocks, as follows: (1) 0 to 5,000 kilowatts; (2) 5,000 to 10,000 kilowatts; and (3) over 10,000 kilowatts. p. 127.

29. RATES, § 333 — Electric rate design — Demand ratchets.

[N.C.] An electric utility's demand ratchet was approved that provided for a minimum monthly billing demand of at least 80% of the maximum summer demand or 60% of the maximum winter demand during the previous 12 months; however, demand ratchets were forbidden for timeof-use rates. p. 128.

30. RATES, § 339 — Electric rate design — Customer classes — Thermal energy storage.

[N.C.] A new electric service rate schedule was created for small general service thermal energy storage (SGS-TES). p. 128.

APPEARANCES: For Carolina Power & Light Company, Richard E. Jones, Vice President and General Counsel, Robert W. Kaylor, Associate General Counsel, Margaret S. Glass, Associate General Counsel, and Rosemary G. Kenyon, Associate General Counsel, Carolina Power & Light Company, P.O. Box 1551 Raleigh North Carolina 27602 and Edward S. Finley, Jr., Hunton and Williams, Attorneys at Law, One Hannover Square, Raleigh, North Carolina 27606; For the Public Staff, Antoinette R. Wike, Chief Counsel, Paul L. Lassiter, Staff Attorney, and James D. Little, Staff Attorney, Public Staff — North Carolina Utilities Commission, P.O. Box 29520, Raleigh, North Carolina 27626-0520, For The Using and Consuming Public; For the Attorney General, Jo Anne Sanford, Special Deputy Attorney General, Karen E. Long, Assistant Attorney General, Lorinzo L. Joyner, Associate Attorney General, and Lemuel W. Hinton, Assistant Attorney General, North Carolina Department of Justice, P.O. Box 629, Raleigh, North Carolina 27602-0629, For The Using and Consuming Public; For the Consumer Interest of the U. S. Department of Defense (DOD) and Other Affected Executive Agencies, David A. McCormick, Regulatory Law Office, Office of the Judge Advocate General, U. S. Department of the Army (JALS-RL), 5611 Columbia Pike, Falls Church, Virginia 220415013; For the Carolina Industrial Group for Fair Utility Rates (CIGFUR II), Ralph McDonald and Carson Carmichael, III, Bailey, Dixon, Wooten, McDonald, Fountain and Walker, Attorneys at Law, P.O. Box 12865, Raleigh, North Carolina 27605-2865; For the Conservation Council of North Carolina, John Runkle, Attorney at Law, Post Office Box 4135, Chapel Hill, North Carolina 27515; For the Carolina Utility Customers Association, Inc. (CUCA), Thomas R. Eller, Jr., Attorney at Law, Suite 205, Crabtree Center, 4600 Marriott Drive, Raleigh, North Carolina 27612; For Herself (As a customer of Carolina Power & Light Company), Elizabeth Anne Cullington, Route 5, Box 440, Pittsboro, North Carolina 27312.

Before Hipp, presiding, and Wright and Redman, commissioners.

By the COMMISSION:

On January 6, 1987, Carolina Power & Light Company (Applicant, Company, or CP&L) filed an application with the North Carolina Utilities Commission (Commission) seeking authority to adjust and increase electric rates and charges for certain customers served by the Company in North Carolina. The application seeks rates that produce approximately $173.4 million of additional annual revenues from the Company's North Carolina retail operations when applied to a test period consisting of the 12-months ended March 31, 1986, for an approximate

13.07% increase in total North Carolina retail rates and charges. The Company requested that such increased rates be allowed to take effect for service rendered on and after February 5, 1987.

The principal reasons set forth in the application necessitating the requested increase in rates were: (1) the need to include in rates a portion of the Harris Plant investment which when added to construction work in progress already in rate base represents approximately 50% of the total Harris plant investment; and (2) the need to recover the costs associated with adding new transmission and distribution facilities, maintenance and modification work at generating facilities, the Robinson Nuclear Unit's steam generator replacement, and other increases in the Company's overall cost of providing service.

With its application, the Company filed an Undertaking to Refund the revenues applicable to 50% of the depreciation expense and associated taxes and 50% of the Harris Plant capital costs over and above the amount presently reflected in rates pursuant to N.C.G.S. 62-133(b)(1) if these amounts were found in the second case to have been imprudently incurred.

On February 3, 1987, the Commission entered an Order suspending the Company's proposed rates for a period of up to 270 days from the proposed effective date pursuant to G.S. 62-134.

On March 11, 1987, the Commission entered an Order pursuant to G.S. 62-137 declaring the Company's application to be a general rate case establishing the test period, scheduling public hearings requiring the Company to give public notice of its application and the scheduled hearings and requiring intervenors or other parties having an interest in the proceeding to file interventions, motions, or protests in accordance with applicable Commission rules and regulations.

The Company's application included a motion whereby the Commission was requested to enter an order authorizing deferral accounting of costs related to the Harris Plant during the period between commercial operation and the date the Commission issued its final order in this docket. The Commission previously authorized similar deferral of operating costs and fuel savings for Duke's McGuire Unit 2 in Docket No. E-7, Sub 373, for Catawba Unit 1 in Docket No. E-7, Sub 391, and for Catawba Unit 2 in Docket No. E-7, Sub 408. On March 2, 1987, at the Commission's regularly scheduled staff conference, the Public Staff recommended that CP&L's motion for deferral accounting of costs related to Harris Unit 1 be allowed. The Attorney General's Office noted its objection to the motion. The Commission entered an Order on March 31, 1987, approving CP&L's Undertaking filed with its application and allowing the motion for deferral accounting except that the proposal by CP&L to reflect precommercial and postcommercial fuel savings related to Harris Unit 1 in customers' bills through the EMF was not approved, and instead such fuel savings would be netted against the costs included in the deferred account. The Commission further provided that all parties would be given the opportunity to present testimony in CP&L's next general rate case concerning the appropriate level of deferred operating expenses, capital costs, and fuel savings and the appropriate amortization period and ratemaking treatment of these items, and in the event that a portion of the Harris Plant is disallowed in that proceeding the level of deferred costs would be adjusted to reflect the disallowance.

On January 12, 1987, the United States Department of Defense filed its Petition to Intervene, which was allowed by Commission Order dated January 14, 1987.

On January 14, 1987, the Carolina Industrial Group for Fair Utility Rates (CIGFUR II) filed its Petition to Intervene which was allowed by Commission Order dated January 19, 1987.

On January 16, 1987, the Attorney General of North Carolina filed Notice of Intervention in this docket pursuant to G.S. 62-20 on behalf of the using and consuming public.

On January 21, 1987, the Conservation Council of North Carolina filed its Petition to Intervene, which was allowed by Commission Order dated January 23, 1987.

On February 2, 1987, the Carolina Utility Customers Association, Inc. (CUCA), filed its Petition to Intervene. In its Petition to Intervene, CUCA moved that the Commission dismiss the application of CP&L for reasons stated therein, without prejudice to CP&L's right to refile using a test year consisting of the twelve months ended December 31, 1986. Both the Public Staff and CP&L filed responses to CUCA's Motion to Dismiss CP&L's Application. On March 11, 1987, the Commission issued an Order that allowed CUCA's intervention but denied CUCA's Motion to Dismiss CP&L's Application.

On May 20, 1987, Elizabeth Anne Cullington filed a Petition to Intervene on behalf of herself, which was allowed by Order of the Commission dated June 3, 1987.

On May 1, 1987, CP&L filed an application in Docket No. E-2, Sub 533, for an annual fuel charge adjustment proceeding pursuant to G.S. 62-133.2 and NCUC Rule R8-55. By letter accompanying the application, CP&L asked the Commission to schedule a hearing on the application so as to allow for issuance of a final order coincident with the final order issued in this docket. On May 18, 1987, the Attorney General filed a Motion to Consolidate Docket No. E-2, Sub 533, with this docket, contending that holding separate hearings would be administratively wasteful. On May 21, 1987, CUCA joined in the Attorney General's Motion for Consolidation, but also renewed its Motion to Dismiss the general rate case application. On May 22, 1987, CP&L filed a Response in which it stated that it would not object to consolidation of the hearings on the two proceedings, but that separate orders should be issued in the two dockets. By Order of May 26, 1987, the Commission denied CUCA's renewed Motion to Dismiss CP&L's Application but allowed the Motions of the Attorney General and CUCA insofar as they sought to have the hearing on CP&L's fuel charge application held concurrently with this rate case hearing.

An Order scheduling a prehearing conference for Wednesday, June 3, 1987, was entered by the Commission on May 22, 1987. The prehearing conference was held as scheduled before Sammy R. Kirby, Commission Hearing Examiner. Based upon statements which were offered and made by counsel and Ms. Cullington during the prehearing conference, the Commission entered a Prehearing Order on June 4, 1987, for the purpose of establishing basic procedures for the hearing.

Public hearings were held as scheduled by the Commission for the specific purpose of receiving testimony from public witnesses. The following persons appeared and testified during the period May 26, through June 9, 1987:

Goldsboro: Jimmy Braswell, Durwood Farmer, Larry Jinnette, Lloyd Massey, Rodney M.

Tart, James A. Hodges, Jr., Jim Barnwell, Edwin H. Allen, Butler Holt, and Rachel Jefferson.

Asheville: Carol W. McCurry, J. B. Campbell, George Roberts, Jean Ritchie, Odessa Richardson, Bob Kendrick, Morris Fox, Horace Constance, Bruce Peterson, Dorothy Kirschbaum, Tom Wilson, Richard Patzfahl, Irmgard Gordos, James A. Barrett, Wilbur Eggleston, Rosal Lee Davidson, Janis Luther, Rae Gibbons, F. W. Woody, Fred Sealy, June Collins, Carolyn Tingle, David Spicer, Kathy Rogers Jay Cole, Charles Brookshire, Gordon Hinners, Bob Gessner, Betty Parker, E. C. Bradley, Albert Ward, Pete Post, Ben Robinson, Helen T. Reed, Kate Jayne, Robert Taylor, Garrett Alderfer, Walter Kleina, Claudine Cremer, Lou Zeller, and David Gettleman.

Wilmington: Sandra Barone, Bernard Efford, Dan Williams, Robert Toplin, Grace A. Everett, Annie Mae Southerland, John Terrell, John McCoy, Closenu Sharp, Ron Shackelford, Steve Bader, and Sister Joan Keller.

Raleigh: Martha Drake, Gene Kornegay, Margaret Keller, Portia Brandon, Wells Eddleman, Bill Delamar, Travis Jackson, Laird Staley, Mark Marcoplos, Jesse W. Dry, Jr., Ronney Watt, Jonathan Laurer, John K. Nelms, Gerald Folden, Gus Anderson, Mason Hawfield, Jeff Smith, Helen Wolfson, Debbie Cooper, Bernard Herzbach, W. W. Finlator, Bruce E. Lightner, Ernest Hanford, Jim Berry, Anna Hawkins, David Kirkpatrick, Bernadine Weddington, Jane Montgomery, Jim Barnwell, Jane Sharp, Christopher Scott, and William N. McCormick.

A substantial number of the public witnesses specifically praised the level of service provided by the Company, while a few criticized the level of service. Most of the public witnesses opposed the rate increase, including some who were not customers of the Company. Several of the public witnesses were specifically opposed to the Harris nuclear plant, including some who were not customers of the Company.

On June 1, 1987, CP&L filed supplemental testimony and exhibits in this case. Included was the loss associated with the cancellation of Mayo Unit 2 and a recommendation that the loss be amortized over five years. The Public Staff and the Attorney General filed a joint Motion on June 5, 1987 opposing consideration of ratemaking treatment associated with the cancellation of Mayo Unit 2 until CP&L's next general rate case. The Commission ordered that consideration of the abandonment of Mayo Unit 2 should be delayed until CP&L's next rate case by Order dated June 16, 1987.

The case in chief came on for hearing on June 9, 1987. At the beginning of the hearing, the Company and the Public Staff presented a signed stipulation that adopted as facts certain portions of Public Staff witness Linda P. Haywood's testimony. That stipulation was accepted by the Commission.

CP&L offered the testimony and exhibits of the following witnesses: Sherwood H. Smith, Jr., President, Chief Executive Officer and Chairman of the Board of Directors of Carolina Power & Light Company, testified generally as to the Company's need for the proposed rate increases the commercial operation of Unit 1 of the Shearon Harris Nuclear Station the Company's financial condition and capital requirements and its operating efficiency; James H. Vander Weide, Professor of Finance and Economics at the Fuqua School of Business at Duke University, testified as to rate of return on equity capital required for CP&L; Paul S. Bradshaw, Vice

President and Controller of CP&L, testified as to the revenues, expenses, and rate base amounts from the Company's books and known changes in levels of expense, as well as to the Company's capital structure; David R. Nevil, Manager of Rate Development Administration in the Rates and Services Practice Department of CP&L, testified to the actual operating results of the Company for the test year, including a cost of service study and certain pro forma adjustments used in the adjusted cost of service study; and Norris L. Edge, Vice President for the Rates and Service Practices Department of CP&L, testified with respect to the proposed revenue increase, the rate design objectives, and the Company's load management activities. Testifying about fuel charge adjustments to the base fuel calculation were Larry L. Yarger, Manager of Fossil Fuel; Ronnie M. Coats, Assistant to the Group Executive, Fossil Generation and Power Transmission Group of CP&L; and David R. Nevil.

The Attorney General offered the testimony and exhibits of the following witnesses: Jocelyn M. Perkerson, Accountant with the Energy and Utilities Division of the Department of Justice, testified with respect to some of the income tax issues under the Tax Reform Act of 1986; David A. Schlissel of Schlissel Engineering Associates Belmont, Massachusetts, testified with respect to base fuel factor calculations and alternative methodologies for normalizing the capacity factors of CP&L's nuclear units; Caroline M. Smith of J. W. Wilson and Associates, Inc., Washington D.C., testified with respect to the cost of capital and rate of return.

Intervenor CUCA offered the testimony of John W. Bowyer, Professor of Finance, Washington University, Kirkwood, Missouri, who testified about the cost of capital and rate of return.

The Conservation Council of North Carolina offered the testimony of Wells Eddleman of Durham, North Carolina, who testified regarding the efficient use of energy improvements in energy efficiency, and the impact of energy efficiency in rate design and ratemaking on various issues. The Conservation Council also presented Dr. Robert B. Williams and Dr. Allin Cottrell of Elon College, who presented a report entitled "Does Shearon Harris Make Economic Sense?"

The United States Department of Defense (DOD) and other affected federal executive agencies offered the testimony of Suhas P. Patwardhan, P. E., of Oklahoma City, Oklahoma, who testified concerning cost of service and rate design, particularly large general service rates and large general service time-of-use rates.

CIGFUR II presented Nicholas Phillips, Jr., of St. Louis, Missouri, who testified concerning cost allocation and rate design. Other CIGFUR II witnesses were: Edward P. Schrum, Utilities and Maintenance Supervisor at the Monsanto Agricultural Company Plant at Fayetteville; Carl W. West, Energy Manager of the Weyerhaeuser Company's New Bern Pulp Mill operation; Robert B. Patterson, III, Energy Engineer at Champion International Corporation's Canton Mill; Herman S. Sears, Plant Manager of LCP Chemicals' plant at Riegelwood; Warren R. Bailey, Vice President and General Manager for Huron Tech Corporation in Delco; and Paul W. Magnabosco, Energy Coordinator for Federal Paper Board's Riegelwood operation. These witnesses generally cited the need for equitable distribution of costs between rate classes, the disparity between N.C. industrial rates and those elsewhere in the Southeast, and their efforts to conserve energy.

The Public Staff offered the testimony and exhibits of the following witnesses: George T.

Sessoms, Director of the Economic Research Division, testified as to the Company's capital structure, cost of capital and rate of return; Richard J. Durham, Engineer with the Electric Division, testified with respect to CP&L's cost of fuel and fossil fuel inventory; Thomas S. Lam, Engineer with the Electric Division, testified on cost of service methodology; Benjamin R. Turner, Engineer with the Electric Division, testified on rate design and plant depreciation; Jane Rankin, Accountant with the Accounting Division, testified on the working capital allowance; Linda P. Haywood, Accountant with the Accounting Division, testified with respect to the impact of costs arising from CP&L's agreements with the North Carolina Eastern Municipal Power Agency (NCEMPA or Power Agency) upon the North Carolina retail revenue requirement; and Candace A. Paton, Accountant with the Accounting Division, presented written testimony with respect to the accounting and ratemaking adjustments made by the Public Staff. For purposes of crossexamination, William E. Carter, Jr., Director of the Accounting Division, adopted Ms. Paton's testimony.

The Company offered rebuttal testimony of David R. Nevil after the intervenors presented their evidence. Mr. Nevil's rebuttal testimony concerned the adjustments recommended by Public Staff witness Linda P. Haywood.

Prior to and during the course of the hearings, various other motions were made and orders were entered relating thereto, all of which are matters of record. Additionally, pursuant to various Commission orders or requests, also of record, various parties were directed or permitted to file and serve certain late-filed exhibits, either during or subsequent to the hearings held in this matter.

On July 28 and 30, 1987, the Commission issued its Order Requiring Filing of Data and Supplemental Order Requiring Filing of Data requesting CP&L and the Public Staff to provide certain data as detailed therein in order to enable the Commission to set forth accurately and specifically the findings of fact in this Order. Other parties were given an opportunity to comment on the calculations. The data was filed as requested on July 31, 1987. On August 4, 1987 comments were filed by the Public Staff and the Attorney General.

The Commission has received various letters and petitions regarding this matter. These have been filed with the Chief Clerk; however, this case has been decided on the basis of the evidence presented at the hearings as hereinafter set forth.

All parties to the proceeding were provided an opportunity to file proposed orders and briefs with the Commission, which were required to be filed on or before July 15, 1987, and July 17, 1987, respectively.

On August 5, 1987, the Commission issued a Notice of Decision and Order in this docket which stated that CP&L should be allowed an opportunity to earn a rate of return of 10.45% on its investment used and useful in providing electric utility service in North Carolina. In order to have the opportunity to earn a fair return, CP&L was authorized to adjust its electric rates and charges to produce an increase in gross revenues of $92,467,000 on an annual basis. CP&L was also required to file proposed rates and charges necessary to implement the allowed rate increase in accordance with rate design guidelines established by the Commission.

On August 10, 1987, CP&L filed its proposed rates and charges as required by the

Commission. On August 21, 1987 the Commission issued an Order Approving Tariff Filing.

Based on the foregoing, the verified application, the testimony and exhibits received into evidence at the hearings, 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. CP&L is engaged in the business of developing, generating, transmitting, distributing, and selling electric power and energy to the general public within a broad area of North Carolina, with its principal office and place of business in Raleigh, North Carolina.

2. CP&L is a public utility corporation organized and existing under the laws of the State of North Carolina and is subject to the jurisdiction of this Commission. CP&L is lawfully before this Commission based upon its application for a general increase in its North Carolina retail rates and charges pursuant to the jurisdiction and authority conferred upon the Commission by the Public Utilities Act.

[1] 3. The test period for purposes of this proceeding is the 12-month period ended March 31, 1986, adjusted for certain known changes based upon events and circumstances occurring up to the time of the close of the hearings in this docket.

4. The overall quality of electric service provided by CP&L to its North Carolina retail customers is good.

5. By its application, CP&L initially sought an increase in its rates and charges to its North Carolina retail customers of approximately $173,351,000, which would produce jurisdictional revenues of $1,499,228,000, based upon a test year ending March 31, 1986. Annualized revenues under present rates, according to CP&L, were $1,325,877,000, thereby necessitating this increase. On June 1, 1987, the Company filed supplemental testimony which did not request additional revenues but purported to justify additional revenues of $22,900,000 over and above the $173,351,000.

6. CP&L's contracts to sell 16.17% of Mayo Electric Generating Plant Unit 1 and Shearon Harris Nuclear Power Plant Unit 1, 12.94% of Roxboro Steam Electric Plant Unit 4, and 18.33% of Brunswick Steam Electric Plant Units 1 and 2 to the North Carolina Eastern Municipal Power Agency consisted of three agreements: the Purchase, Construction and Ownership Agreement (Sales Agreement), the Operating and Fuel Agreement, and the Power Coordination Agreement (PCA). These contracts collectively have resulted in the cost of electricity to CP&L's North Carolina retail customers being lower than that cost would have been had CP&L itself financed the plant. Therefore these contracts are reasonable and prudent, as used in determining the revenue requirement in this particular proceeding. The reasonable application of the terms of these contracts in determining the North Carolina retail revenue requirement in this proceeding requires the utilization of current costs and buyback percentages; recognition of the effects of the Tax Reform Act of 1986; utilization of the cost of common equity approved in this Order in the calculation of purchased capacity capital costs; and levelization of purchased capacity capital costs and purchased demand-related expenses, in order to prevent the overcollection of these

costs by the Company. The reasonable amount of levelized purchased capacity costs and nonfuel purchased energy costs for use in this proceeding is $23,562,000.

7. CP&L should be allowed to include 50% of the Harris Plant Unit 1 in rate base and 50% of the related depreciation expense and associated taxes in its operating revenue deductions and to continue to defer and accrue carrying costs on the remaining 50% of the Harris Plant and depreciation and associated taxes consistent with the final Commission Order in Docket No. E-2, Sub 511. The inclusion of operation and maintenance expenses including fuel savings, property taxes, and other expenses is at a 100% level in this proceeding. The cost of Harris Unit 1, comprising both the Company's ownership interest and the Power Agency purchased capacity, is not otherwise an issue in this case with respect to the reasonableness of the construction costs. Pursuant to the Commission Order entered in Docket No. E-2, Sub 511, the reasonableness and prudence of the construction costs of the Harris Plant will be decided in CP&L's next general rate case.

8. The summer/winter peak and average method, including the minimum system technique and with the allocation factors adjusted to reflect the Power Agency buyback percentages utilized in the case, Power Agency Reserve Capacity, and normalization of Power Agency Actual Entitlement Energy, is the most appropriate method for making jurisdictional cost allocations and for making fully distributed cost allocations between customer classes in this proceeding. Consequently, each finding of fact appearing 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 method as described herein.

9. A base fuel component of 1.242¢/kWh excluding gross receipts tax and including nuclear fuel disposal cost is reasonable and appropriate for this proceeding, resulting in a reasonable total fuel cost of $270,641,000 for North Carolina retail service. Nuclear fuel disposal cost is a proper component of the cost of fuel and should be reflected in the established fuel factor. A normalized system nuclear generation mix using the average of CP&L's lifetime nuclear capacity factors by unit through March 31, 1987 and the latest 10-year industry average data for boiling water (BWR) and pressurized water (PWR) reactors from the North American Electric Reliability Council's Equipment Avail ability Report is appropriate for this proceeding for the Brunswick Units 1 and 2 and Robinson Unit 2. This normalization is consistent with Commission Rule R8-55 and results in normalized capacity factors of 54.375% for Brunswick Unit 1, 51.61% for Brunswick Unit 2, and 63.46% for Robinson Unit 2. The Harris nuclear unit should be normalized based on a 70% capacity factor. These normalized capacity factors by unit result in a reasonable and representative normalized system nuclear capacity factor of 60.07% which is appropriate for use in this proceeding.

10. The appropriate working capital al lowance for coal inventory for North Caro lina retail service is $49,101,000.

11. The reasonable allowance for total working capital for CP&L's North Carolina retail operations is $104,749,000.

12. CP&L's reasonable original cost rate base used and useful in providing service to the public within the State of North Carolina is $2,882,526,000 consisting of electric plant in service

of $3,923,646,000, net nuclear fuel investment of $123,424,000, and an allowance for working capital of $104,749,000, reduced by accumulated depreciation of $836,080,000 and accumulated deferred income taxes of $433,213,000.

13. The appropriate level of gross revenues for CP&L for the test year, under present rates and after accounting and pro forma adjustments, is $1,325,856,000.

14. The reasonable level of test year operating revenue deductions for CP&L after normalization and pro forma adjustments is $1,074,649,000.

15. CP&L's reasonable and appropriate level of federal income tax expense in this case should be based on the use of a 40% blended rate. During the approximate sevenmonth period extending from January 1, 1987, through August 5, 1987, CP&L has overcollected its federal income tax expense by approximately $26,859,000, excluding interest. Such overcollection is the result of the Company's current rates including provisional components reflecting a 46% federal income tax rate when in fact the actual rate as required by the Internal Revenue Code for calendar-year taxpayers like CP&L is 40% for 1987.

16. CP&L's existing schedule of depreciation rates is appropriate for use in computing depreciation expenses in this case, but the Company should prepare a study supporting its depreciation rates for presentation in its next general rate case proceeding.

17. The capital structure for the Company which is reasonable and proper for use in this proceeding is as follows:

[Table below may contain distortions.]

Item	Percent
Long-term debt	48.5 %
Preferred stock	8.5 %
Common equity	43.0 %
Total	100.00%

18. The fair rate of return that CP&L should have the opportunity to earn on its North Carolina net investment for retail operations is 10.45% which requires additional annual revenues from North Carolina retail customers of $92,467,000, based upon the Company's adjusted level of operations for the test year ended March 31, 1986. This rate of return on CP&L's total net investment yields a fair rate of return on CP&L's original cost common equity of approximatey 12.63%. Such rate of return will enable CP&L, by sound management, to produce a fair return for its shareholders, to maintain its facilities and service in accordance with the reasonable requirements of its customers, and to compete in the market for capital on terms which are reasonable and fair to customers and existing investors. The proper embedded cost rates for long-term debt and preferred stock are 8.81% and 8.74%, respectively.

19. Based upon the foregoing, CP&L should be authorized to increase its annual level of gross revenues under present rates by $92,467,000. After giving effect to the approved increase, the annual revenue requirement approved herein is $1,418,323,000, which will allow CP&L 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 CP&L's property used and useful in providing service to its North Carolina retail customers and its reasonable test year operating revenues and expenses as previously set forth in these findings of fact.

20. Lower than average increases should be applied to the large general service customer class while average increases should be applied to the residential and small general service classes in order to move toward equalizing class rates of return.

21. Demand charges in the large general service rate schedule should be increased to three billing blocks based on size of demand.

22. The Company should prepare a study of the differences in kWh usage attributable to the various traffic signal configurations for presentation with its next general rate case.

23. The Company should file a plan for monitoring the on-peak loads of customers served under new rate schedule SGS-TES in order to analyze the impact of such loads on the system.

24. The rate designs, rate schedules, and service rules proposed by the Company are appropriate and should be adopted, except as modified herein.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1, 2, AND 3

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, procedural, and jurisdictional in nature, and the matters which they involve are essentially uncontradicted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

The evidence for this finding of fact concerning the quality of service is found in the testimony of Company witness Smith and the various public witnesses who appeared at the hearings in Asheville, Wilmington, Goldsboro, and Raleigh. The Commission notes that the record contained little, if any, evidence which would suggest any problems as to the adequacy of CP&L's service. A careful consideration of all of the evidence bearing on this matter leads the Commission to conclude that the quality of electric service being provided by CP&L to retail customers in North Carolina is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence supporting this finding of fact is contained in the Company's verified application, the Commission Order entered in this docket on March 11, 1987, and the testimony and exhibits of the Company's witnesses.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

[2] The evidence supporting this finding of fact is found in the testimony and exhibits of Public Staff witness Haywood and Company witnesses Smith, Bradshaw, and Nevil. Public Staff witness Haywood testified that on July 30, 1981, CP&L and the North Carolina Eastern Municipal Power Agency (Power Agency or NCEMPA) became parties to agreements whereby certain portions of several of CP&L's generating plants were sold to Power Agency. Power Agency, a municipal corporation composed of thirty-two (32) cities and towns, operates and maintains electric distribution systems located in eastern North Carolina. CP&L and Power Agency executed three agreements. The first agreement known as the Purchase, Construction and Ownership Agreement (also referred to as the Sales Agreement), established the maximum interests in generating capacity which CP&L agreed to convey to Power Agency. In the Sales Agreement, CP&L sold to Power Agency undivided interests in certain of its generating facilities and associated fuel. Power Agency's ownership in these joint facilities originally included as much as 18.33% of the Brunswick Steam Electric Plant, Unit Nos. 1 and 2, near Southport, North Carolina (nuclear-fueled; in service); 12.94% of Unit No. 4 at the Roxboro Steam Electric Plant located in Roxboro, North Carolina (coal-fired; in service); 16.17% of the Mayo Electric Generating Plant, Unit Nos. 1 and 2, in Person County, North Carolina (coalfired; under construction at the time of the sale); and 16.17% of the Shearon Harris Nuclear Power Plant, Unit Nos. 1, 2, 3, and 4, near New Hill, North Carolina (nuclear-fueled; under construction at the time the Agreements were signed). Harris Unit Nos. 3 and 4, however, were cancelled prior to the First Closing, and Unit No. 2 was cancelled after the First Closing. Mayo Unit No. 2 has also been cancelled. After the cancellation of Harris Units 2, 3, and 4, and Mayo Unit 2 the Power Agency ownership percentage of these cancelled units was changed to 12.94%. The Power Agency's ownership interest in fuel is the same as its ownership interest in the Joint Unit to which the fuel relates.

In the second agreement, known as the Operating and Fuel Agreement, CP&L has agreed to be solely responsible for the operation and maintenance of the Joint Units. In addition CP&L acts as operator and dispatcher of the Joint Facilities and serves as project manager of the construction of any capital additions to or modifications of the Joint Facilities. Power Agency reimburses CP&L for its ownership share of the construction and operating costs of the Joint Units.

The third agreement, the Power Coordination Agreement, provides for the interconnection of the CP&L system with the Joint Units and the Power Agency's participants' electric distribution systems. The terms pursuant to which CP&L furnishes to Power Agency the necessary supplemental power, transmission services, and backstand services are also found in this agreement. Moreover, this agreement established an arrangement by which CP&L will buy back from Power Agency some of the capacity and energy from Power Agency's ownership interests in the Mayo and Harris Units in declining amounts over a 15-year period beginning at 50% in the first year of commercial operation and declining by 3.33%, each year down to 0% in the 16th year.

The Commission finds that the uncontroverted description of the agreements presented by Public Staff witness Haywood and stipulated to by CP&L as being factually correct is an accurate account of the provisions found in the terms of the contracts.

Public Staff witness Haywood testified that these contracts overall were beneficial to the North Carolina retail customers. Company witness Smith testified that because of the exempt-from-tax nature of Power Agency's debt, its long-term debt costs are three to five percentage points below that of the Company. Witness Smith also testified that Power Agency, being a nonprofit organization, pays no dividends to its stockholders. Witness Haywood and witness Smith both discussed the split savings concept, whereby CP&L and Power Agency developed a formula that enabled both parties to split the difference between their respective costs of capital. Under this theory, the Power Agency would realize a profit from the buyback, but the cost of the power to CP&L would be less than what it would have been had CP&L financed the entire plant itself.

Based upon all the evidence set forth hereinabove, the Commission concludes that the Power Agency agreements as presented in this proceeding are beneficial to the North Carolina retail customers. Therefore, the Commission finds that the costs associated with these contracts are prudent and reasonable, and should be appropriately reflected in the rates set in this proceeding. The Commission notes, however, that this finding is made on the basis of the agreements as they and their costs have been presented and explained to the Commission in this docket. There may be costs implicit in the agreements which have not yet been presented to the Commission. Additionally, over the term of the agreements, it may be necessary for CP&L to negotiate matters of interpretation or negotiate modifications, any of which may involve additional costs to the ratepayers. The Company should not assume that such additional future costs will be passed on to the ratepayers automatically on the basis of the present finding. Any such additional costs will be subject to the Commission's review and evaluation on a case-by-case basis.

The Company and the Public Staff disagree as to the appropriate treatment to be given various components of the cost of power bought back by CP&L from Power Agency. The following schedule sets forth the differences between the Company and the Public Staff as to the appropriate level of purchased capacity and nonfuel energy expense related to the Harris and Mayo Units:

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[Table below may contain distortions.]

  Harris and Mayo
  Purchased Capacity
  and Nonfuel Energy
  Costs
Item   (000's)

Amount per company using 12CP
  cost of service study $ 40,304
Difference due to Public Staff adjust-
  ments to reflect change to adjusted
  SWPA cost of service study includ-
  ing witness Haywood's allocation
  factor adjustments (760)
Company reallocated amount 39,544
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Other Public Staff adjustments:
  Utilization of 1987 estimated Mayo
    costs (98)
  Weighting of buyback percentages
    and energy normalization (2,082)
  Weighting of federal income tax
    rates (619)
  Utilization of Public Staff
    recommended return on
    common equity (3,911)
  Levelization of purchased capacity
    costs (11,907)
Total other Public Staff adjustments (18,617)
Amount Per Public Staff $ 20,927
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The difference between the Company and the Public Staff due to the Public Staff's adjustments to the allocation study is discussed in conjunction with the Evidence and Conclusions for Finding of Fact No. 8. In accordance with that finding of fact, the Commission concludes that an adjustment of $819,000 to reduce the Company's recommended level of Harris and Mayo purchased capacity and nonfuel energy costs is appropriate rather than the Public Staff's $760,000 adjustment.

[3] The first of the remaining differences between the Company and the Public Staff relates to the utilization of estimated 1987 costs for the Mayo buyback. Public Staff witness Haywood testified that the Company used 1987 estimated costs related to the Harris Plant, while using test-year costs for the Mayo Plant. Public Staff witness Haywood testified that since the amount deferred under the Public Staff's levelization recommendation will be based upon ongoing costs, it is appropriate to reflect the most current costs possible in the initial calculation of adjusted purchased capacity and nonfuel energy costs. Witness Haywood also stated that the usage of the 1987 Mayo estimated costs does not create a material difference from the Company's per books amount. In performing her calculations, witness Haywood also used Harris 1987 estimated costs just as the Company had done. The Company contended during its cross-examination of witness Haywood that it is inappropriate to match 1987 costs with buyback percentages based partly on 1987 and partly on 1988. Public Staff witness Haywood responded that this is the same methodology used by Duke Power Company and approved by the Commission in Docket No. E-7, Sub 408.

The evidence shows that the Mayo 1987 estimated costs are not materially different from the test year level of costs, and since Harris Unit 1 did not begin commercial operation until May 2, 1987, it is necessary to use Harris 1987 estimated costs. The Commission, therefore, concludes that the use of Mayo and Harris estimated 1987 costs are representative of the ongoing costs that the Company is actually experiencing. The Commission also agrees that using 1987 costs is appropriate to reflect the most current cost possible in the initial calculation of adjusted purchased capacity and nonfuel energy costs, since the amount deferred under the levelization plan approved herein will be based on ongoing costs.

The Commission recognizes that this is the same methodology approved in Duke Power Company's last general rate case (Docket No. E-7, Sub 408) with regard to the costs of Catawba

Unit 1.

The Commission disagrees with the Company's contention that the combination of 1987 estimated costs with the weighted 1987/1988 buyback percentage is an inappropriate matching. In many instances the Commission uses cost rates and levels that are not restricted by the bounds of the test year. Examples of such in this case include unit fuel costs and nonrevenue-producing plant investment. There are various reasons for adopting these costs; however, one unifying factor that they have in common is that they are independent of the measures of service which delineate the test year (number of customers, kWh sales, kW demand, etc.). Therefore, for example, one can adopt a unit fuel cost from a time period after the test year and apply it to test year generation without resulting in an inappropriate matching. Moreover, the unit fuel cost does not have to be taken from the same time period as the nonrevenueproducing plant amount, because they are independent of each other.

[4] Public Staff witness Haywood has utilized Harris and Mayo estimated costs from 1987, a period beyond the end of the test year. The fact that these cost rates are from a period beyond the test year does not violate the test year matching concept, since purchased capacity and nonfuel energy cost rates are independent of and do not rely on the measures of test year service. More importantly, the combination of 1987 cost rates and 1987/1988 buyback percentages is not an inappropriate matching because these items are independent of each other. The unit cost rates will not change simply because of a change in the buyback percentages. Witness Haywood has utilized the most current annual cost she had available, and applied the ongoing buyback percentages to that. The Commission concludes in this proceeding that such a treatment does not result in an inappropriate matching of costs with buyback percentages.

The second difference of $2,082,000 between the Company and the Public Staff relates to the appropriate treatment of the buyback percentages and energy normalization associated with the Harris and Mayo Units. In regard to the energy normalization piece of this adjustment, the Public Staff reflected its recommended normalized generation associated with Harris and Mayo in calculating the level of purchased mWh to be used in its calculation of purchased nonfuel energy costs. Consistent with its decisions set forth in the Evidence and Conclusions for Finding of Fact No. 9 regarding normalized generation, the Commission concludes that the appropriate levels of purchased mWh generation to be reflected in its calculation of purchased nonfuel energy costs are 428,838 mWh for Harris and 215,880 mWh for Mayo.

In support of the other part of the $2,082,000 difference, as it relates to the buyback percentages, Public Staff witness Haywood presented prefiled testimony stating that pursuant to Article 5.3(A) of the Power Coordination Agreement (PCA), the purchases (buyback) with respect to Harris begin when the unit goes into commercial operation and continue for 15 years in amounts declining from 50% of Power Agency's ownership interest in the first year to 0% in the 16th year. It is also stated in Article 5.3(B) of the PCA that:

> For each of the Units, Year 1 shall begin on the date of Commercial Operation of each unit. If such date of Commercial Operation occurs prior to July 1, Year 1 shall end on December 31 of that calendar year. If such date of Commercial Operation occurs on or after July 1, Year 1 shall end on December 31 of the next succeeding year.

Witness Haywood stated that the Company projected and reflected in its filing a 50% buyback for the entire 12 months of its pro forma test year, the expected first year of operation of the Harris Unit. Harris officially became commercial on May 2, 1987. As stated above, given the plant's actual commercial operation date, the PCA provides that 1987 be recognized as the first year of operation, coupled with a 50% buyback. The agreement also requires that the buyback percentage decrease to 46.667% on January 1, 1988, which would be the beginning of the second year of operation. Therefore, according to witness Haywood, in order to accurately recognize the effect of the contracts upon the current operations of the Company, the Public Staff utilized a weighted average of the first (1987) and second (1988) year buyback percentages to better reflect the ongoing costs associated with the buyback. The weightedaverage percentage of the Public Staff is based upon the 50% buyback in effect for the five remaining months in 1987, under the assumption that the rates set in this proceeding go into effect on August 1, 1987; plus, seven months of 1988 at a 46.667% buyback. The resulting Harris buyback weighted-average percentage is 48.055%.

Witness Haywood testified that Mayo Unit 1 began commercial operation on March 1, 1983; consequently, the buyback percentage has been declining from 50% by 3.333% per year since that date. In its filing, the Company calculated the Mayo buyback percentage based on purchases for the first nine months of the test year (April 1985 through December 1985) at 43.333% plus the last three months of the test year (January 1986 through March 1986) at 40%. The average purchased capacity and energy percentage for the test year resulting from this weighting is approximately 42.4%. Witness Haywood testified that she determined the appropriate Mayo weighted buyback percentage the same way she did for Harris. The only distinguishing factor is the fact that the buyback percentages are different due to different commercial operation dates. Thus, witness Haywood testified, the appropriate Mayo weighted-average buyback percentage was 34.722% calculated by the weighting of the 36.667% buyback in effect for the five remaining months in 1987 and the 33.333% buyback in effect for the first seven months of 1988.

During cross-examination of witness Haywood, counsel for the Company implied that there were problems with using the 1987 and 1988 weighted-average percentages related to the buyback provision, because such an approach goes beyond the test-year period and even beyond the time of the hearing. However, Public Staff witness Haywood testified that the change in the buyback percentages occurring on January 1, 1988, is a known change. She testified that this change is reflected in the terms of the existing Power Coordination Agreement. Company witness Nevil agreed that under the terms of the PCA the buyback percentages change at the beginning of each calendar year. Witness Haywood further stated that the percentages which she used in the determination of purchased capacity and nonfuel energy costs are those which will be in effect for the year beginning August 1, 1987, the expected date of the Final Order in this proceeding.

The treatment of the buyback percentages recommended by the Public Staff has been accepted by the Commission in each of Duke Power Company's two most recent general rate cases (Docket No. E-7, Subs 391 and 408). The Commission is of the opinion that the costs of purchased capacity and energy should be included on an ongoing basis; that is, they should reflect the most current factors applicable and admissible per G.S. 62-133(c). The Commission concludes that the change in the buyback percentages occurring on January 1, 1988, is in fact a known change that reflects the actual and currently existing terms of the Power Coordination Agreement. The Commission is aware of the fact that the percentages used by witness Haywood in this proceeding to determine the purchased capacity and energy costs reflect the percentages that the Company is presently using in its 1987 buyback calculation and will be using in the 1988 calculation as well. The Commission concludes that the weighting of the 1987 and 1988 buyback percentages, recommended by the Public Staff is appropriate and reasonable. This conclusion is also consistent with the treatment given Duke Power Company for similar situations. The Commission thus concludes that it is appropriate to weight purchased capacity and energy costs using the buyback percentages in effect for the final five months of 1987 and the first seven months of 1988. To adopt the Company's position would result in the overrecovery of these costs, before consideration of levelization.

[5] The third difference between the Company and the Public Staff concerns the appropriate income tax components within the calculation of the purchased capacity capital costs for Harris and Mayo. Public Staff witness Haywood testified that there were several factors which necessitated this adjustment. The major factor was the Tax Reform Act of 1986, which changed the maximum corporate federal income tax rate from 46% to 34% on July 1, 1987. Calendar year corporate taxpayers, however, will utilize a blended rate during 1987 of approximately 40%. Further, purchased capacity capital costs paid each year are based upon the income tax rates in effect for the year. During 1987, the capital cost of purchased capacity is being calculated by CP&L using the 40% blended federal income tax rate. During 1988, however, the 34% federal income tax rate will be used. Thus, witness Haywood testified, purchased capacity capital costs will differ in 1987 and 1988 due to the known change in the utilized tax rate. Therefore, it is proper to weight the income tax components of purchased capacity capital costs in the same manner as recommended by the Public Staff for the buyback percentages (i.e., for 1987 a 40% tax rate is used and for 1988 a 34% tax rate is used).

Public Staff witness Haywood also testified that this adjustment is not in conflict with Public Staff witness Carter's recommendation that a 34% federal income tax rate should be used to calculate income tax expense in the cost of service, and that the two issues are entirely different. Witness Haywood stated that witness Carter's income tax adjustment dealt with the Company's actual income tax expense liability, whereas her adjustment concerned the income tax rate that CP&L reflects in its actual purchased capacity cost calculation pursuant to the terms of the Power Agency agreements.

Witness Haywood stated that one area affected by her adjustment to the income tax components was the average earning base used in the purchased capacity capital cost calculation, due to the effects of the reduction in tax rates on average accumulated deferred income taxes. Other areas affected were the income tax component of return as well as income taxes due to the nonallowance of allowance for funds used during construction as a tax deduction.

Based on the foregoing, the Commission concludes that the treatment of the income tax components within the purchased capacity capital cost calculation as recommended by the Public Staff which incorporates tax rates of 40% for 1987 and 34% for 1988 is reflective of the terms in the contracts and the ongoing costs of purchased capacity under those terms. The Commission concludes that the Public Staff's treatment in this regard should be adopted for use in this proceeding.

During witness Haywood's cross-examination, she stated that Haywood Exhibit I, Schedules 3-1(b) and 3-2(b) "Revised," line 5, may reflect incorrect amounts used for the investment tax credit (ITC) amortization. Witness Haywood stated that this had been brought to her attention shortly before her appearance before the Commission, and she would review the Company's contention as soon as possible, but pointed out that Company representatives acknowledged that the revenue impact of this error was slight.

In its proposed order the Public Staff presented adjustments which reflect the correction of this error. As previously presented, the Public Staff's adjustments relating to the calculation of purchased capacity capital costs totaled $6,710,000, and the levelization adjustments totaled $11,907,000. Upon correction of its treatment of the ITC amortization for 1988, the Public Staff presented adjustments totaling $6,668,000 and $11,906,000, respectively. Based upon these revised figures, the Public Staff recommended that the Harris and Mayo purchased capacity and nonfuel energy costs be included in the cost of service at a level of $20,970,000.

The Commission concludes that the ITC amortization within the purchased capacity capital cost calculation should be expressed on a pretax basis; therefore, the 1988 amounts should be based on a federal tax rate of 34% as corrected by the Public Staff, rather than 40% as initially proposed by the Public Staff. The purchased capacity capital cost approved herein by the Commission reflects the appropriate treatment of the ITC amortization component in this regard.

[6] The fourth difference between the Company and the Public Staff relates to the appropriate rate of return to be used in the calculation of purchased capacity capital costs. In this calculation, the parties differ as to the appropriate rate of return on common equity to be used. Both the Company and the Public Staff agree that the rate allowed by the Commission in this proceeding will become the constraining return for the contractual calculation as soon as the Order is issued. The Company has utilized its current allowed return on equity of 15.25% as the basis for its Harris purchased capacity capital costs and the return actually paid during the test year for Mayo. Public Staff witness Haywood has utilized the Public Staff's recommended return on common equity of 11.79% for both units.

The Commission concludes that the rate of return on common equity allowed in this proceeding is the appropriate rate to be used for ratemaking purposes in calculating the capital cost of purchased capacity related to the Harris and Mayo Units. Use of this rate of return fairly and reasonably reflects the ongoing return component of purchased capacity capital cost, since this rate will become the benchmark per the terms of the PCA upon the issuance of this Order. Therefore, based upon the Evidence and Conclusions for Finding of Fact No. 18, the Commission concludes that the use of 12.63% is appropriate for this proceeding.

[7] The fifth difference between the Company and the Public Staff relates to the levelization of the reasonable level of purchased capacity costs associated with the Harris and Mayo Units. The Public Staff recommended a levelization plan that extends over the lives of the buybacks from Power Agency. The plan provides for the levelization of both purchased capacity capital costs and purchased demand-related expenses. The levelization as it relates to the Harris plant would extend to December 31, 2001; the levelization related to the Mayo plant would extend to December 31, 1997. The costs deferred due to levelization would accrue a return calculated at the overall netof-tax rate of return. Public Staff witness Haywood testified that such a levelization would benefit the ratepayers of the Company. Witness Haywood stated that levelization of these costs would make it possible to avoid either or both of the following two events: (1) frequent proceedings to reduce the revenue requirement as both the purchased capacity capital costs and the demandrelated costs decline over time due to the continuing decline in the amounts of power bought back from Power Agency, and (2) the overcollection of these costs by the Company if no such rate proceedings take place due to the above-mentioned decline.

The chart below, presented at the hearing as Public Staff Smith Cross-Examination Exhibit No. 5, sets forth the position of the Public Staff as to the effect of not levelizing these costs using the Public Staff's initial cost recommendation in this proceeding.

[Graphic Not Displayed Here]

This chart shows the Public Staff's contention that absent the effect of any subsequent rate proceedings, the Company will increasingly overrecover the purchased capacity costs unless levelization is adopted. Without levelization, rates would be set at the current buyback percentages, and the decline of the buyback percentages in future years would not be recognized by adjustments in rates, unless a rate case was held each year. Thus, revenues would continue to flow in at a fixed level, while those costs would decline by 3.33% per year. In response to this exhibit, Company witness Smith agreed that what it sets forth would occur if the Company did not come in each year for a rate hearing, unless increasing costs offset the overrecovery and no mechanism was provided to adjust for changing costs.

Public Staff witness Haywood testified that levelization of purchased capacity costs would not impair the Company, because through the return accrued on the costs deferred under levelization the Company will be made whole for all of these costs. Witness Haywood testified that the Company should establish a deferred account or accounts to track the difference between the costs of purchased capacity and the levelized recovery. Under her recommendation, the account would accrue a return equal to the overall rate of return approved in this case, and such return would be compounded at the end of each calendar year. The deferrals and the return would be maintained on a net-of-tax basis. Witness Haywood testified that under her recommendation the deferred costs would equal the difference between the costs actually incurred and the levelized amount recovered, so that the Company would recover all of the costs included in the levelization plan.

Company witnesses Smith, Bradshaw, and Nevil testified that the Company objects to the levelization plan proposed by witness Haywood. Witness Bradshaw stated that the Company's major concern was that witness Haywood's levelization plan could constitute a phase-in under regulations presently proposed by the Financial Accounting Standards Board (FASB). He further stated that a phase-in not qualified under the FASB statement could cause the Company to suffer adverse financial conditions. The proposed Statement of Financial Accounting Standards (SFAS) is described in Public Staff Bradshaw Cross Examination Exhibit Nos. 1 and 2. According to the exhibits, a phase-in plan is defined as any method of ratemaking that meets the following criteria:

(a) It was adopted in connection with a major recently completed plant of the utility or one of its major suppliers or a plant scheduled for completion in the near future.

(b) It defers cost recognition compared to generally accepted accounting principles applicable to enterprises in general.

(c) It defers cost recognition compared to the methods routinely used for that utility by that regulator for similar costs prior to December 1982.

According to Public Staff Bradshaw CrossExamination Exhibit No. 1, all of the following criteria must be met in order to capitalize deferred costs related to a phase-in plan in accordance with generally accepted accounting principles:

(a) The costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.

(b) The plan specifies the timing of recovery of all costs that will be deferred under the plan.

(c) Rate increases scheduled under the plan must not be backloaded (in terms of annual percentage increases in rates they must be straight-line or decreasing).

(d) All costs deferred under the plan are scheduled for recovery within 10 years of the date when deferral begins.

Company witness Smith testified that the Company opposes the Public Staff's levelization plan, because it would not meet the 10-year recovery criterion. Witness Bradshaw stated that his concern was that the levelization plan and the Harris phase-in plan could be considered as one plan and therefore the failure of the levelization plan to meet the FASB criteria could affect the entire Harris plant phase-in.

During cross-examination, however, witness Bradshaw agreed that the proposed SFAS has been pending for three years, but stated that he was hopeful that the statement will be issued prior to year-end 1987. Witness Bradshaw also agreed that there is a difference of opinion as to whether or not the proposal will even include levelization as a phase-in in its final form. The Company contended that it was not against levelization in principle, as long as the Company was permitted to recover all of the levelized costs but would rather wait until the next case, and perhaps by then the "uncertainties" concerning what is simply the latest draft of this Proposed FASB statement would no longer exist.

Public Staff witness Haywood testified that there are two basic uncertainties regarding this pending SFAS. First, it is not certain that a final statement will be issued in the near future. Second, it is not clear that the statement, if eventually issued, will even apply to the levelization plan that she is recommending. Witness Haywood further testified that given these uncertainties, she continues to recommend that the levelization period extend over the lives of the buybacks. She also added that if a SFAS is issued after her testimony in this case, if the Company presents evidence, including a statement from its auditors and/or other authoritative sources, showing that the provisions of the SFAS apply to the levelization plan, and if the Public Staff agrees with that evidence, the Public Staff would not oppose appropriate modification of the levelization plan at an appropriate time. Company witness Bradshaw testified under cross-examination and Public Staff witness Haywood agreed that the proposed FASB rule also provides transitional rules which provide an opportunity for modification of any plan not in compliance with the final statement prior to the statement becoming applicable to that particular plan.

Company witness Smith testified that the Company's proposal for handling the costs associated with the buyback of Harris plant capacity from the Power Agency is more appropriate than that of the Public Staff, because the Public Staff's proposal to levelize those costs would lead to a larger percentage rate increase in the Company's next rate case. Witness Smith further testified that if levelization is adopted in this case, then the Company would receive a lower percentage increase in this case and that would therefore mean that the requested percentage increase in the next case would be higher. Witness Smith testified that this would defeat the Company's objective of a steady, level phase-in of the overall rate increase over two cases.

During witness Haywood's cross-examination by Company counsel Kenyon, witness Haywood was asked if her deferred account constituted retroactive ratemaking. Company witnesses Smith and Bradshaw also contended that the levelization plan proposed by witness Haywood was not developed in such a way that allows the Company an opportunity to recover all of its purchased capacity costs in the future. Witness Haywood stated that based upon the advice of her counsel her plan does not constitute retroactive ratemaking. Witness Haywood further testified that her levelization plan provides a vehicle that enables the Company to recover costs that she had estimated for some 15 years in the future, in an attempt to ensure that ratepayers do not overpay in rates for costs that are declining each year. Witness Haywood testified that the deferred account that she has recommended is a vehicle which the Company can utilize to keep track of the difference between the actual costs and levelized payments. Witness Haywood testified that for rate cases occurring during the levelization period, the amount in the deferred account would be flowed into the levelization calculation so that the Company would recover all its costs during the remainder of the levelization period. She further stated that in her opinion the Public Staff's plan is reasonable.

Company witness Nevil testified that the Public Staff did not "levelize" the North Carolina retail allocation factors in the same way it levelized the costs of the buyback. Witness Nevil testified that such a "levelization," which would involve the adjustment of the allocation factors to reflect the impact of the decreasing buyback in each year through the year 2001, was necessary to match the decline in system costs for the next 15 years with the increase in the allocation factors.

Based upon all the evidence presented in this proceeding, the Commission concludes that the levelization of purchased capacity costs provides significant benefits to the Company's ratepayers and should be adopted. Levelization will compensate for the known decreases in capacity purchases in the coming years and will protect ratepayers from overpaying while protecting and preventing the Company from undercollecting the costs being levelized. All of these benefits will be realized without the frequent proceedings which could otherwise be necessary to provide them.

[8] Therefore, the Commission concludes that the Company's revenue requirement in this proceeding due to Harris and Mayo purchased capacity costs should be calculated by use of a levelization plan which includes the levelization of both the purchased capacity capital costs and the purchased demand-related expenses for the Harris and Mayo units. The difference between the levelized cost and the Company's actual Harris and Mayo purchased capacity payments should be placed in a deferred account and should accrue a return based upon the overall-net-of-tax rate of return approved by the Commission in this proceeding. Said return should be calculated tilizing a federal income tax rate of 40% in 1987 and 34% in 1988 and beyond, in accordance with the Commission's findings regarding income taxes. The return so calculated should be compounded at the end of each calendar year after the date of this Order. In rate cases occurring during the levelization period, the Commission instructs that the actual balance in the deferred account should be adjusted as necessary to reflect the estimated balance at the Order date in that case, and should be flowed into the levelization calculation so that it would be recovered during the remainder of the levelization period. The Commission of course retains discretion as to the determination of the appropriateness, accuracy, and reasonableness of the deferred balances proposed for flow-in in any future proceeding. The Commission concludes that maintenance of the deferred account in this manner will enable the Company to recover, but not overrecover, the actual costs subject to levelization.

The Commission concludes that the abovedeferred account does not constitute retroactive ratemaking. The above accounting treatment is consistent with the Commission's treatment of Catawba Unit 1 levelized purchased capacity costs in Docket No. E-7, Sub 408,and the positions expressed by the Public Staff at the hearing in that proceeding. The Commission realizes that levelization is a vehicle that provides the Company with a means of recovering the actual costs associated with purchased capacity incurred over the lives of the buybacks. At the same time, the ratepayers do not overpay for these declining costs. In the Commission's Final Order in each of the two Duke Power Company rate proceedings in which it has approved levelization of portions of purchased capacity costs (Docket No. E-7, Subs 391 and 408), the Commission has instructed that the deferred account should include the difference between the levelized payment and the actual amount of the cost being levelized. The Commission also finds the deferred account to be a reasonable method of allowing the Company the opportunity to recover its costs while not causing the ratepayers to overpay for these costs.

The Commission notes the fact that the deferred account is not necessary in order to levelize costs. The levelization plan could be implemented without providing a mechanism which allows the Company to recover its actual costs. Such a levelization would simply rely on estimates of ongoing costs, a normal ratemaking procedure. In an attempt to reflect fairness to all parties concerned, however, the Commission agrees with the Public Staff in its recommendation to allow the Company an opportunity to recover its actual costs through the deferred account and earn a return on deferred revenues. Therefore, the Commission concludes that the Public Staff's recommendation for use of a deferred account is both reasonable and appropriate in this proceeding.

The Commission is aware of the basic uncertainties surrounding the pending Statement of Financial Accounting Standards as to its effective date and its application to the levelization plan recommended by Public Staff witness Haywood. At this time, the Commission has no means of determining when the pending statement will be issued, whether the statement will apply to the levelization plan recommended by witness Haywood, or whether or not the pending statement will be retroactive. The Commission notes, however, that under the current FASB proposal, if the final statement applies to the levelization plan, CP&L certainly has the option to request a modification of the levelization. The Commission recognizes its obligation to set rates as low as reasonably possible without delay. Keeping this premise in mind, the Commission concludes that the Company's proposal to wait and perhaps levelize in the next general rate case after the issuance of the pending statement should be rejected. The Commission agrees, however, that if the final statement is issued in the near future, and if the statement applies to the levelization plan, and if the plan is not in compliance with the final statement (specifically, the 10-year recovery criterion), the Company should request a modification that will ensure compliance.

The Commission concludes that the assertions of witness Smith as to the effect of levelization upon the percentage rate increase allowed by the Commission in this and the Company's next rate proceeding are not adequate to justify a delay of levelization until the next proceeding. The Commission agrees with witness Haywood's testimony that levelization benefits the ratepayers without harming the Company; CP&L will be made whole regardless of the case in which levelization is adopted. The Commission has an obligation to set rates as low as reasonably possible. Levelization, in the opinion of the Commission, is reasonable and should be adopted in this case in order to provide the benefits of a lower revenue requirement to the ratepayers.

The Commission does not agree with the Company that the levelization it has approved herein and the phase-in of the Harris plant investment and capital costs adopted in Docket No. E-2, Sub 511, could be considered as only one phase-in plan for the entire facility. These plans are totally separate from each other and were adopted in response to different issues and different situations.

The Commission concludes that Company witness Nevil's contention that allocation factors should be "levelized" in the same way that the costs of purchased capacity are being levelized is incorrect and should not be adopted in this proceeding; nor does it provide justification for not levelizing purchased capacity costs. While it is true that allocation factors may change in the future, the impact of the buyback on the factors is only one of many potential changes. The Commission cannot predict what these changes will be, or whether they will act to increase or decrease North Carolina retail costs. Moreover, an allocation factor is not an independently existing entity outside of a Commission proceeding. It is a mechanism used by the Commission to set fair and reasonable rates. The Commission chooses to not predict what those factors will be 15-years in the future. The variability in the allocation factors as they apply to levelization is a risk no different from the variability in the factors as they apply to any other cost in this rate proceeding. The Company is already being afforded significant protection in the levelization plan by the establishment of the deferred account; the Commission finds that it would not be reasonable or practical to attempt to afford it additional protection by trying to predict allocation factors for 15-years into the future. Moreover, the Commission concludes that the allocation factors found reasonable in this proceeding should be used to determine the North Carolina retail deferral pursuant to levelization, until such factors are reviewed in the Company's next general rate case proceeding.

Based upon all of the conclusions stated hereinabove, the Commission finds that the level of Harris and Mayo purchased capacity and nonfuel energy expenses appropriate for use in this proceeding is $23,562,000 for purchased capacity and nonfuel energy costs. This amount reflects the following adjustments to decrease the Company's proposed amounts for purchased capacity and nonfuel energy costs:

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[Table below may contain distortions.]

Adjustment to reflect Commis-
  sion adjusted SWPA $ 819,000
Harris purchased capacity and
  energy $4,505,000
Mayo purchased capacity and
  energy $1,173,000
Levelization of Harris pur-
  chased capacity $9,333,000
Levelization of Mayo pur-
chased capacity $ 912,000
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These adjustments are consistent with the Commission's decisions on: the appropriate cost of service study, utilization of Harris and Mayo 1987 estimated costs, buyback percentages, energy normalization, weighting of federal income tax rate — 40% for 1987 and 34% for 1988 and beyond, and capital structure with related cost rates.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

[9] The evidence for this finding of fact concerning Harris Plant rate base is contained in the testimony of Company witnesses Smith and Bradshaw, North Carolina Conservation Council witness Eddleman, and Professors Williams and Cottrell of the Department of Economics at Elon College, and in the Commission Order entered in Docket No. E-2, Sub 511, on July 24, 1986 (77 PUR4th 203). That Order established principles and procedures for the plant phase-in of the Shearon Harris Nuclear Station and deferral of certain costs associated with the phase-in. Among the procedures established in that Order was a requirement that the Company should include no more than 50% of the capital costs of the Harris Plant in rate base and depreciation expense of no more than 50% of the cost of the Harris Plant in operating expenses in any general rate case the Company filed prior to April 15, 1987. The aforementioned costs and expenses are subject to refund. Further, the Commission ordered that any issues pertaining to the reasonableness and prudence of the costs associated with the Harris Plant would be litigated in the first general rate case filed by the Company on or after April 15, 1987.

As Company witness Smith testified, CP&L has included in rate base in its filing 50% of the Harris Plant, which in the Company's original filing was approximately $858 million on a North Carolina retail basis. The Company updated this value to approximately $910 million to reflect the actual cost of Harris as of April 30, 1987. The Company has also included only 50% of depreciation expense and income taxes related to the Harris Plant. All other expenses are included at a 100% level. Witness Smith testified that in this way the Company was complying with the July 24, 1986, Order of the Commission in Docket No. E-2, Sub 511, regarding the phase-in of the Harris Plant. Additionally, witness Smith testified that in accordance with that Order, issues pertaining to the reasonableness or prudence of Harris costs will be reserved until the second rate case to be filed by the Company.

Witness Smith testified that the Harris Plant is needed to provide adequate and reasonable capacity and noted that the Commission recognized that fact in its Order in the Company's most recent load forecast hearing in Docket No. E-100, Sub 50. He further testified that without the Harris Plant the projected reserve margin would fall to 16.7%, well below the minimum reserve margin of 20.0% which the Commission has consistently found to be appropriate.

Witness Eddleman presented testimony that primarily focused on the impropriety of including Harris in rate base as construction work in progress (CWIP). However, since Harris was declared commercial on May 2, 1987, it can no longer be classified as CWIP but must be classified as plant in service. As such, the criteria under which CWIP can be included in rate base are not relevant.

Elon Professors Williams and Cottrell filed a report in this proceeding entitled "Does Shearon Harris Make Economic Sense?: An Evaluation of the Cost of Shearon Harris and its Alternatives." In this report, Professors Williams and Cottrell examined three alternatives to operating the Harris Plant. These alternatives were: first, the building of a new coal-fired generating unit; second, the purchase of power from other utilities; and, third, investment in conservation measures. Each of these three alternatives assumed the cancellation of the Harris Plant with a return of stockholders' capital over l5 years with no return on the unamortized investment during that period. The professors conclude that each of the three alternatives is less costly than the Harris Plant, although alternatives one and two are quite close to the cost of the Harris Plant. The conservation alternative is presented as being considerably less costly but also more speculative.

On cross-examination by the Company, Professors Williams and Cottrell were unable to verify three key assumptions made in their analysis: (1) that 900 mW of firm power was available for purchase by the Company at 3.2¢/kWh until the year 2000; (2) that shares of ownership in unscrubbed coal-fired generating units were available for purchase by the Company at $1,000/kW and 3.0¢/kWh for the next 30 years; and (3) that reported purchases of power by the Company at 3.2¢/kWk were firm purchases instead of spot market purchases.

The economic model developed by Professors Williams and Cottrell for their study utilized a 9% discount rate for investments in power plants and a 3% discount rate for other investments, and it failed to consistently utilize end-of-year input values. The Company contended that consistent use of end-of-year input values and consistent use of a 3% discount rate for all investments would result in the economic model showing the Harris Plant to be lower cost than either the coal plant option or the purchased power option.

Cross-examination by the Company indicated that the conservation option was seriously flawed by the assumption made in their economic model that air conditioners, water heaters, and 40% of light bulbs would operate for all 8,760 hours of the year for 30 years. The Company contended that air conditioners operate approximately 1,000 hours per year, that light bulbs operate approximately 1,600 hours per year, and that the erroneous assumptions caused an eightfold error in the results of the model for the conservation option.

Professors Williams and Cottrell contended in their report that repaying the $3.3 billion investment cost in the Harris Plant over a 15-year period and paying a zero percent real interest rate on the unreimbursed portion of the $3.3 billion investment for each year of the 15 years would not have significantly adverse effects on the ability of the Company to continue financing its operations. The Company contended that repaying the $3.3 billion over a 15-year period would result in repaying only $2.6 billion of the $3.3 billion (in present value terms).

Having carefully reviewed the report of Professors Williams and Cottrell, the Commission is not persuaded that the alternatives proposed in the report would be of lower cost than the Harris Plant. The Commission does recognize the effort given the project by the professors and is receptive to the focus on conservation measures which the professors presented. This Commission will continue to encourage conservation and load management as a means of reducing the need for costly new capacity.

In conclusion, the Commission reaffirms its decision in Docket No. E-2, Sub 511, regarding the reasonableness of phasing-in the Harris Plant over two cases. This decision allowed the Public Staff adequate time to conduct its audit of the Harris Plant and also mitigated rate shock for the ratepayers. As the Commission has concluded in its load forecast proceedings, the Harris Plant is needed to provide reasonable and reliable capacity. Because ratepayers are protected from inclusion of imprudent or unreasonable costs in rates due to the fact that the amount of the increase in this case associated with the increment in Harris cost above the amount already included in rates as CWIP is subject to refund, it is reasonable to include in this case the cost of 50% of the Harris Plant on an interim basis, recognizing that the customer benefits from 100% of the plant output. The Harris Plant is needed; $663 million of CWIP related to the Harris Plant had been deemed reasonable for inclusion in rates in Docket No. E-2, Sub 481; and the phase-in of the Harris Plant is believed by this Commission to110 be in the best interest of the ratepayer. The Company is allowed to defer and accrue carrying costs on the remaining 50% of the Harris Plant and depreciation and associated taxes consistent with the final Commission Order in Docket No. E-2, Sub 511. It is also concluded that CP&L is entitled to recover the operating expenses associated with Harris from the date of commercial operation to the date of this Order. CP&L is also entitled to recover the capital costs for this same period associated with all of the Harris Plant which is determined in CP&L's next rate case to be prudent. The amounts of the operating and capital costs and the period over which they are recovered will be determined in CP&L's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

Company witness Nevil, Public Staff witnesses Haywood and Lam, CIGFUR witness Phillips, and Department of Defense witness Patwardhan presented testimony on cost allocation methodology or adjustments to the cost allocation studies.

Cost Allocation Methodology

[10, 11] Inasmuch as CP&L provides retail service in North Carolina and South Carolina as well as wholesale service to certain municipalities and electric membership cooperatives and supplemental service to the North Carolina Eastern Municipal Power Agency (NCEMPA), its total system costs must be allocated to the various jurisdictions in order to fix cost responsibility. The jurisdictional cost allocation study serves to fix the North Carolina retail jurisdiction cost responsibility in this rate proceeding. The fully distributed cost allocation study serves to fix cost responsibility among the various North Carolina retail customer classes. The Commission initially adopted the peak and average method for allocating production plant in the cost allocation studies in Docket No. E-2, Sub 391, using only the summer peak. In Docket No. E-2, Sub 444, the Commission modified the Company's peak and average method by using a combination of the summer and winter peaks. This was the method proposed by the Company and adopted by the Commission in Docket No. E-2, Subs 461, and 481.

Pursuant to Commission Order in Docket No. E-2, Sub 481, the Company filed cost allocation studies in this case based on the following methodologies: summer/winter peak and average (SWPA), 12-month coincident peaks (12CP), and summer coincident peak (SCP). The results of these studies show the effects of various methods of allocating production plant and other system costs. The SWPA method classifies some portion of production plant as demandrelated and some portion as energy related. The demand-related component is then allocated based on kW contribution to both the summer and winter peaks. The energyrelated portion is allocated based on generation level kWh. The 12CP method classifies all production plant as demand-related and allocates the plant based on kW contribution to each of the system's 12 monthly peaks. The SCP method classifies all production plant as demand-related and allocates the plant based on kW contribution to the system's summer peak demand.

Company witness Nevil recommended using the 12CP method for allocating production plant, contending that: (1) it has been adopted by the Federal Energy Regulatory Commission; (2) it allocates less demand cost to off-peak time and thus supports time-of-use pricing concepts; and (3) it encourages improvement in the system load factor.

Public Staff witness Lam recommended that production plant be allocated using the SWPA method. In his recommended SWPA method, the portion of plant classified as demand-related and allocated by kW peak demand equals 1 minus CP&L's system load factor, and the portion of plant classified as energy-related and allocated by average demand or kWh equals the system load factor. Witness Lam explained that the 12CP method or any coincident peak method fails to recognize a most important factor in the selection of generating units, the energy requirement of the total system. He said that in the planning process, the size of additional capacity is governed by peak demand growth, but the type of unit required, i.e., peaking, intermediate, or baseload is determined by the energy requirement for the total system. He pointed out that if peak demand is the only consideration, as would seem to be the case in any coincident peak methodology, a system would consist solely of peaking units (because of their low initial capital cost), but that these peaking units would not be able to supply the energy requirements of the system.

CIGFUR witness Phillips recommended that the Commission adopt either the summer coincident peak method or the summer/ winter coincident peak method for allocating production plant. He contended that capacity costs are fixed and therefore related to system demands, not kWh sold. Still, he supported the l2CP method as a better choice than the peak and average method.

DOD witness Patwardhan supported the Company's proposal to use the 12CP allocation methodology on grounds similar to those stated by witness Nevil.

The Commission is not convinced that now is the time to change cost allocation methodologies. Adoption of the 12CP methodology would allocate approximately $10 million additional revenue requirement to the North Carolina retail jurisdiction according to the studies in evidence. The Commission is reluctant to shift a greater portion of the cost of production facilities from industrial customers to nonindustrial customers and at the same time add a $10 million revenue requirement to all North Carolina retail customers.

Minimum System Technique

[12] In this proceeding, the Company proposed to discontinue the use of its minimum system technique for allocating a portion of distribution plant between customer classes. The minimum system technique derives the cost of distribution plant as if all components of such plant are "minimum" size (i.e., the minimum size needed to connect each customer to the system regardless of the amount of kWh used). The cost of the "minimum" distribution plant is then allocated between customer classes on a per customer basis while the remainder of the distribution plant cost is allocated between customers on the basis of distribution level kW demand. The Company contended that the allocation of a portion of distribution plant on a per customer basis should result in such distribution cost per customer being reflected in the basic customer charge in order to be consistent with the allocation methodology. However, such reflection of minimum distribution plant costs in the basic customer charges would result in residential customer charges at least double the current $6.65 per month, and the Commission has never approved residential customer charges approaching the levels indicated by the minimum system technique. The Public Staff supported the Company's proposal.

The Commission is of the opinion that the minimum system technique should not be discontinued at this time. The minimum system technique allocates more of the distribution plant to residential customers and less to large industrial customers, and it is conceptually sound even if the results of such technique are not fully reflected in the basic customer charges. Furthermore retention of the minimum system technique will modify somewhat the impact of the SWPA allocation methodology on the industrial class.

Based upon all of the evidence, the Commission concludes that the SWPA method, including the minimum system, is still the most appropriate method of allocating the cost of production plant in this case.

Adjustments to Allocation Inputs

Public Staff witness Haywood testified that she made three adjustments to the cost allocation study proposed by the Public Staff. The first adjustment was an adjustment to the demand and energy levels on which the allocation factors are based in order to reflect her adjustment to the buyback percentages governing the buyback of power from the Harris and Mayo Units by the Company from the Power Agency. The buyback percentages determine the split between the power used by Power Agency pursuant to its partial ownership of Harris and Mayo (i.e., Power Agency retained power) and the power used by Power Agency in excess of its retained power (i.e., Power Agency supplemental power). Since Power Agency supplemental power is included with power used by the other jurisdictions (including the North Carolina retail jurisdiction) in the cost allocation study, then the buyback percentages will affect not only the Power Agency supplemental power but also the demand and energy levels on which the allocation factors are based, including the North Carolina retail allocation factors. Witness Haywood testified that the demand and energy levels contained in the cost allocation study should be adjusted to reflect her recommended buyback percentages consisting of a weighted average of five months of 1987 buyback percentages and seven months of 1988 buyback percentages for Harris and Mayo.

In his rebuttal testimony, Company witness Nevil argued that traditional ratemaking practices included pro forma accounting adjustments in the cost allocation studies but did not include pro forma demand or energy levels or pro forma cost allocation factors. He contended that the adjustment to buyback percentages was not the only accounting adjustment which could affect demand and energy levels or cost allocation factors, and that any adjustment to cost allocation factors should reflect all proposed accounting adjustments and not just the adjustment to buyback percentages.

On cross-examination of his rebuttal testimony, Company witness Nevil stated that his use of a pro forma 1987 buyback percentage for Harris was appropriate, because there was no test year value. He further testified that the Company's use of a pro forma 1987 buyback percentage for Mayo was incorrect since there was an actual test year percentage that could have been used. After the close of the hearings, witness Nevil provided a late-filed exhibit reflecting the changes in his position by using the actual test year buyback percentage for Mayo. However, the changes reflected in his late-filed exhibit do not appear to be incorporated into the numbers set forth in the Company's proposed order as its final position in this proceeding.

The second adjustment witness Haywood made to the cost allocation study was to add to Power Agency supplemental load an amount representing the reserve capacity necessary to backstand the Power Agency retained load (i.e., Power Agency Reserve Capacity). She contended that costs associated with Power Agency Reserve Capacity have already been recovered by the Company from the Power Agency and should not be recovered again from the North Carolina retail ratepayers. She explained that the Company must provide a reserve margin capable of backing up the portion of generating capacity owned by Power Agency, just as it must provide a reserve margin capable of backing up the portion of generating capacity owned by CP&L, and that Power Agency pays CP&L for such Reserve Capacity. The monthly charge per kW is based upon the Company's average annual production cost per kW, and the amount of kW subject to the monthly charge is the Power Agency Retained Capacity for that month times the percentage reserve capacity available to the total system in the preceding calendar year. The revenue collected by CP&L for Power Agency Reserve Capacity is directly assigned to Power Agency in the jurisdictional cost allocation study. However, the cost associated with the Power Agency Reserve Capacity is included with all of the Company's other capacity costs in the jurisdictional cost allocation study and is allocated by the cost allocation study to all of the jurisdictions, including North Carolina retail. Witness Haywood contends that the North Carolina retail jurisdiction thus bears some of the cost associated with the Power Agency Reserve Capacity but does not receive credit for any of the revenues collected by CP&L from Power Agency.

Company witness Nevil disagreed in his rebuttal testimony with the Public Staff's adjustment to the Power Agency supplemental load in order to reflect Power Agency Reserve Capacity. He contended that when witness Haywood made an adjustment for Power Agency Reserve Capacity, she should have also made corresponding adjustments for other comparable situations such as for those retail customers on the system who subscribe to standby service. Witness Nevil stated that reserve capacity is provided for retail customers who subscribe to standby service, in a manner similar to the reserve capacity provided for Power Agency retained capacity. However, this standby situation addressed by witness Nevil was not quantified as an issue by the Company or any other party in this proceeding.

The third and final adjustment witness Haywood made to the cost allocation study was to adjust Power Agency supplemental energy in order to reflect the effect of the Public Staff's recommended normalized generation mix on Power Agency supplemental load. When the generation mix is normalized, the energy produced by that portion of the generation mix representing capacity owned by Power Agency is also normalized. The portion of the system generating capacity owned by Power Agency (i.e Power Agency Retained Capacity) entitles Power Agency to a portion of the energy produced by that capacity (Power Agency Actual Entitlement Energy, or AEE). Since AEE depends not only on the installed generating capacity owned by Power Agency but also on the generating performance of that capacity, any change in the generating performance of such capacity will also change the AEE. Changes in the Power Agency AEE will affect the amount of remaining energy to be allocated to the other jurisdictions, including the North Carolina retail jurisdiction. Therefore, witness Haywood adjusted the North Carolina retail energy allocation factor to reflect the normalized AEE which corresponds to the Public Staff's proposed normalized generation mix.

Company witness Nevil cited in his rebuttal testimony the Commission's decision in the Company's last general rate case in Docket No. E-2, Sub 481, to disallow a similar adjustment to allocation factors proposed by CUCA witness Wilson. He also argued that the sale of generating plant ownership to Power Agency was a package deal which was intended to provide advantages to all parties, and that it would be unfair to subsequently make adjustments in rate cases which take away those advantages to the Company of the negotiated sale. Witness Nevil suggested that if pro forma adjustments were permitted for allocation factors, many potential adjustments, such as for customer growth, weather, and the buyback levelizations, should also be considered.

Under cross-examination witness Nevil testified that the Company had failed to reflect in the allocation study the effect that adding Harris has on the generation of the Mayo and Roxboro coal plants. Witness Nevil agreed that once a nuclear plant is added on a pro forma basis to fuel expense, then the amount of coal used is reduced. The Company, however, had not reduced the generation of the Mayo and Roxboro units within the allocation study to reflect a reduction in coal generation, although it did reflect the increase in nuclear generation resulting from adding in Harris.

Based upon the foregoing evidence, the Commission is of the opinion that the adjustments proposed by the Public Staff are appropriate for purposes of this proceeding. While the Public Staff and the Company each attempted to cite flaws in the adjustments proposed by the other, the concept of adjusting demand and energy input levels in the cost allocation study in order to match adjustments to the Power Agency supplemental load is sound. The Commission's treatment of the adjustments to Power Agency supplemental load in this case is generally consistent with the Commission's treatment in the Duke Power Company rate cases in Docket No. E-7, Subs 391 and 408. The Commission has also benefitted from the additional discussions of the issue which have occurred since the last CP&L rate case in Docket No. E-2, Sub 481 and anticipates continuing discussion of the issue in future rate cases. The Commission adopts the allocation factors resulting from the calculations requested by the Commission in its July 28, 1987, Order in Appendix A items 1 and 2 as appropriate for use in this proceeding rather than those proposed by the Public Staff. These allocation factors are consistent with the Commission's findings as to the appropriate level of normalized generation mix discussed in the Evidence and Conclusions for Finding of Fact No. 9, the Commission level of cogeneration which results in a monthly average of 112,536 kW to be reflected in the calculation of the adjusted system capability used in the reserve capacity adjustment, and the Commission-approved cost of service methodology.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

[13, 14] Company witness Nevil, Public Staff witness Durham, and Attorney General witness Schlissel testified regarding the fuel component to be included in base rates in this proceeding. The Company proposed a base fuel component of 1.430¢/kWh in updated testimony, whereas the Public Staff recommended 1.262¢/kWh, and the Attorney General recommended 1.227¢/kWh.

In his original prefiled testimony, Company witness Nevil proposed a base fuel component of 1.356¢/kWh using a March 31, 1986, test period. The basic assumptions included in this factor were as follows: (1) Brunswick Units 1 & 2 and Robinson Unit 2 operating at capacity factors equal to the average of each unit's lifetime average and the 10-year average of similar type units as reported by the North American Reliability Council (NERC), resulting in capacity factors of 53.125%, 49.87%, and 62.115% for Brunswick Units 1 and 2 and Robinson 2, respectively, and Shearon Harris Unit 1 operating at a 65% capacity factor; (2) exclusion of nuclear fuel disposal costs; (3) median conventional hydrogeneration; (4) pro forma cogeneration at zero fuel price; and (5) annualized coal expense of $19.29 per mWh and oil expense of $97.53 per mWh based on June 1986 burn prices. Witness Nevil updated his base fuel component to incorporate a fuel cost for cogeneration purchases and increased Harris 1 expected performance to a 70% capacity factor. No adjustments were made by the Company to reflect a more current burned cost of fuel in this proceeding. The result of the Company's update increased the proposed factor from 1.356¢/kWh to 1.430¢/kWh (excluding gross receipts tax). The system capacity factor for nuclear generation increased from 57.61% to 59.04% as a result of the update. CP&L further updated its base fuel component to 1.473¢/kWh in its proposed order which resulted from its inclusion of nuclear fuel disposal costs.

Public Staff witness Durham recommended a base fuel component of 1.262¢/kWh also using a March 31, 1986, test period. Witness Durham's basic generation and fuel cost assumptions were as follows: (1) normalization of nuclear generation to a system capacity factor of 60.16% based upon the 10-year average capacity factors of 62.13% for PWRs (including Harris 1) and 58.20% for BWRs as reported in the most recent NERC Equipment Availability Report 19761985; (2) inclusion of nuclear fuel disposal cost; (3) acceptance of the Company's median hydrogeneration; (4) acceptance of the proformed cogeneration calculated by the Company; and (5) price levels of fossil fuels burned in March 1987, with nuclear price levels reflecting the cost of present or scheduled refuelings. The Public Staff opposed the use of lifetime capacity factors to normalize CP&L's nuclear generation. Witness Durham testified that the use of lifetime averages for CP&L's units gives improper weight to periods of operation reflecting abnormally low generation or generally poor periods of operation. He used as an example, Docket No. E-2, Sub 481 where the Commission cited an abnormal extended outage on Brunswick Unit 1 and the abnormal impact of steam generator related problems on Robinson Unit 2 which led to an unacceptable system capacity factor.

Attorney General witness Schlissel recommended a fuel factor of 1.227¢/kWh based on a test period ended March 31, 1987. Witness Schlissel proposed an alternative method for normalizing nuclear generation which would reflect each unit's actual and expected performance resulting in a system capacity factor of 64.9%. For Brunswick Units 1 and 2, witness Schlissel selected the period April 1, 1986, through March 31, 1987, to obtain the units' actual capacity factors and averaged these with CP&L's expected capacity factor for each unit for the period April 1, 1987, through March 31, 1988. For Robinson Unit 2, witness Schlissel averaged the unit's lifetime performance with CP&L's expected capacity factor for that unit for the period April 1, 1987, through March 31, 1988. For Shearon Harris Unit 1, witness Schlissel used the Company's expected capacity factor of 70%. Witness Schlissel used March 1987 fuel prices and included nuclear fuel disposal costs in his fuel factor calculation.

Docket No. E-2, Sub 533, was consolidated with CP&L's general rate case for purposes of hearing. The Sub 533 case involves an application filed by CP&L on May 1, 1987, for a fuel charge adjustment pursuant to G.S. 62-133.2 and Commission Rule R8-55. The test period in the Sub 533 case consisted of the 12 months ended March 31, 1987. Testimony was offered in the fuel charge case by CP&L witness Nevil, Public Staff witness Durham, and Attorney General witness Schlissel. NCUC Rule R855(c)(1) provides that nuclear capacity factors will be normalized based generally on an equally weighted-average of each unit's actual lifetime operating experience and the national average reflected in the most recent NERC Equipment Availability Report, giving due consideration to plants two-years or less in age and to certain unusual events. Pursuant to this rule, CP&L witness Nevil recommended the following unit capacity factors: Brunswick 1, 54.38%; Brunswick 2, 51.61%; Robinson 2, 63.46%; and Harris

1, 70%. These normalized capacity factors result in a normalized total system capacity factor of 60.07%. Public Staff witness Durham recommended normalizing to the NERC averages for each unit as follows: Brunswick 1, 58.2%; Brunswick 2, 58.2%. Robinson 2, 62.13%; Harris 1, 62.13%. The result of his recommendation is a system average capacity factor of 60.16%. Attorney General witness Schlissel recommended a third approach as follows: averaging each unit's actual capacity factor for the period April 1, 1986, through March 31, 1987, and CP&L's expected capacity factor for that unit for the period April 1, 1987, through March 31, 1988, for Brunswick 1 and 2; averaging the unit's lifetime performance and CP&L's expected capacity factor for the unit for the period April 1, 1987, through March 31, 1988, for Robinson 2; and using CP&L's expected 70% capacity factor for Harris. The results of witness Schlissel's recommendations are unit capacity factors of 61.9% for Brunswick 1, 60.7% for Brunswick 2, 66.4% for Robinson 2, and 70% for Harris, and a system average capacity factor of 64.9%. Both CP&L and the Attorney General oppose the use of national averages in normalizing nuclear capacity factors; the Public Staff consistently supports this practice. Both CP&L and the Attorney General also favor recognition of historical experience but with differing results depending upon the historical period that is recognized.

The contested issues related to fuel in this general rate case are clearly identifiable and are as follows: (1) the selection of the 12-month test period; (2) normalization of nuclear generation, (3) cogeneration fuel cost; (4) nuclear fuel disposal cost; and (5) fossil fuel burn data.

Dealing first with the issue of the appropriate test period, the Commission rejects the Attorney General's recommendation to update the test period (using a March 31, 1987, test period) for the purpose of determining a base fuel component. The Commission in Finding of Fact No. 3, has concluded that a March 31, 1986, test period is appropriate for purposes of setting rates in this proceeding. To select different test periods for different aspects of this general rate case would, in the opinion of the Commission, be inconsistent with the provisions of G.S. 62-133(c). The Commission will, however, make pro forma and normalization adjustments to the test period for certain changes through March 31, 1987.

The process of determining the reasonable cost of fuel for CP&L in this proceeding requires the Commission to determine whether it is appropriate to normalize the Company's test year level of nuclear generation for ratemaking purposes. The question regarding whether the actual test year level of nuclear generation should be normalized involves whether such nuclear generation is reasonably representative of the level of nuclear generation which it can be reasonably assumed will occur in the near future and particularly in the upcoming l2-month period. To the extent that the actual test year level of nuclear generation was "abnormal," or not reasonably representative of what should reasonably be expected, then a normalized level should be determined and used.

It is a well established fundamental principle of regulation that public utility rates should be established in a manner so to be representative of the total level of costs a utility can reasonably be expected to experience on an ongoing basis. In other words, prospective rates cannot reasonably be based totally upon a historical test year. Test year data must be normalized so as to reflect anticipated levels of revenues and costs. The normalization concept is one of the most basic precepts of ratemaking. It is a concept which arises out of the statutory requirements that a test year should be used as the basis for a reasonably accurate estimate of what may be anticipated in the near future. Obviously, to the extent that the test year experience reflects an abnormality, such as an abnormally low level of nuclear generation, then it will not result in a reasonably accurate estimate of what may be anticipated in the near future unless an appropriate adjustment is made to "normalize" the abnormality. The Supreme Court of this State has recognized and applied this proposition in numerous decisions. North Carolina ex rel. Utilities Commis sion v. Durham, 282 N.C. 308, 193 S.E.2d 95 (1972); North Carolina ex rel. Utilities Com mission v. Duke Power Co., 285 N.C. 377, 6 PUR4th 390, 206 S.E.2d 269 (1974); North Carolina ex rel. Utilities Commission v. Virginia Electric Power Co., 285 N.C. 398, 6 PUR4th 373, 206 S.E.2d 283 (1974); North Carolina ex rel. Utilities Commission v. Edmisten, 291 N.C. 327, 230 S.E.2d 651 (1976); North Carolina ex rel. Utilities Commission v. Duke Power Co., 305 N.C. 1, 287 S.E.2d 786 (1982); and North Carolina ex rel. Utilities Commission v. Thornburg, 316 N.C. 238 (1986).

The Commission now turns to the question of whether the evidence in this record establishes that the test year level of nuclear generation is normal in the sense of whether it is reasonably representative of what is likely to occur in the near future particularly during the period that the rates set in this case are likely to remain in effect.

The evidence establishes that during the test year ended March 31, 1986, the Company had an overall system nuclear capacity factor of only 54.6%. That overall system nuclear capacity factor is a composite of the actual test year capacity factors of the Company's three nuclear generating units appropriately weighted by generating capacity of each of those units. Those capacity factors included a 33.4% capacity factor for Brunswick Unit 1, a 52.0% capacity factor for Brunswick Unit 2, and an 83% capacity factor for Robinson Unit 2.

During the more recent 12-month period ended March 31, 1987, CP&L achieved a system nuclear capacity factor of 76.6%. During that period, Brunswick Unit 1, Brunswick Unit 2, and Robinson Unit 2 achieved nuclear capacity factors of 73.3%, 60.6%, and 99.5%, respectively. The Company expects to achieve a system nuclear capacity factor of 62.2% for the 12-month period ended March 31, 1988.

The Commission concludes that neither of the system nuclear capacity factors of 54.6% and 76.6% experienced by CP&L during the recent 12-month periods ended March 31, 1986, and March 31, 1987, respectively, were reasonably representative of the system nuclear capacity factor which the Company can reasonably be expected to experience in the near future, including in particular the period of time during which the rates set in this proceeding are likely to remain in effect. The 54.6% system capacity factor for the 12-months ended March 31, 1986, was unreasonably low, while the 76.6% system capacity factor for the 12-month period ended March 31, 1987, was abnormally high. The purpose of normalization is to remove test period abnormalities, either high or low, in setting rates for the future. Commission Rule R8-55(c)(1) generally provides for a method of normalization of nuclear capacity factors based on an equally weighted-average of each nuclear unit's actual lifetime operating experience and the national average for nuclear production facilities as reflected in the most recent North American Electric Reliability Council's Equipment Availability Report. This treatment for ratemaking purposes gives equal weight to CP&L's actual operating experience and 10-year industry averages and provides a reasonable system capacity factor for nuclear normalization purposes. For the Harris Plant, the Commission concludes that CP&L's expected first fuel cycle capacity factor of 70% is reasonable and appropriate for use in this proceeding. Application of the normalization methodology generally specified in Commission Rule R8-55 based upon lifetime nuclear capacity factors calculated through March 31, 1987, results in normalized nuclear capacity factors as follows: Brunswick Unit 1, 54.375%; Brunswick Unit 2, 51.61%; and Robinson Unit 2, 63.46%. The resulting normalized system nuclear capacity factor calculated pursuant to Rule R8-55 is 60.07%. The Commission concludes that the reasonable and appropriate normalized total system nuclear capacity factor for use in this proceeding is 60.07%. The Commission further notes that this normalized system nuclear capacity factor is almost identical to the system factor of 60.16% proposed by the Public Staff based upon 10-year national averages. The Commission will also utilize this same system nuclear capacity factor in CP&L's pending fuel adjustment proceeding, Docket No. E-2, Sub 533.

The Company's position concerning cogeneration is that it should be included in the base fuel component and adjusted annually pursuant to G.S. 62-l33.2. Prior to this general rate case, CP&L has considered cogeneration as a "zero fuel expense" that is recoverable through the Company's base rates. Witness Nevil testified that the cogeneration costs are escalating rapidly and are expected to increase from the $40 million being considered in the present fuel charge adjustment case in Docket No. E-2, Sub 533, to approximately $93 million on an annualized basis by the end of 1987. Witness Nevil also stated that including the costs of cogeneration in the base fuel factor will help avoid the need for frequent rate cases in the future. The Company estimates that the fuel component of its cogenerated purchased power is approximately 4¢/kWh. Witness Nevil's workpapers show that the portion of cogeneration purchases designated as fuel cost is the product of onpeak and off-peak mWh times the levelized avoided fuel cost component of the avoided cost rates presented by CP&L witness King and approved by the Commission in its Order of January 22, 1984, in Docket No. E-100, Sub 41A (64 PUR4th 369).

The Public Staff and the Attorney General opposed the inclusion of cogeneration costs in the fuel factor calculation as proposed by the Company based on their interpretation of G.S. 62-133.2. The Public Staff's position is that the avoided cost rate of 4¢/kWh does not represent the actual cost of fuel burned by the cogeneration facility and, therefore, cannot be adjusted in the fuel factor pursuant to G.S. 62-133.2. Witness Durham testified that the Company had not accurately determined the actual cost of fuel burned by cogeneration.

The Commission is of the opinion that the recovery of the actual fuel cost component of cogeneration purchases is authorized by G.S. 62-133.2 and is, therefore, eligible for inclusion in the fuel factor analysis. It appears impossible in this case, however, to determine the fuel cost component of CP&L's cogeneration purchases in the same way the fuel cost component of the Company's other purchased power is determined. The Commission rejects the Company's proposal to shift the estimated fuel cost of cogeneration from base rates to the fuel component at this time. The evidence clearly shows that the fuel cost component of cogeneration purchases which CP&L seeks to include in the fuel factor is the estimated avoided fuel cost of the Company derived from its calculations of avoided costs in Docket No. E-100, Sub 41A, rather than an embedded or actual fuel cost of the cogenerator. In recognition of the fact that CP&L's

cogeneration costs are escalating rapidly, the Commission has concluded that the level of operating and maintenance expense included in the cost of service should be increased to reflect the level of energy and capacity components of cogeneration costs as of the end of the 12-months period ended March 1987 as more particularly set forth in Evidence and Conclusions for Finding of Fact No. 14.

Both the Public Staff and the Attorney General have recognized the changing cost of fossil fuel and thus use March 1987 burn prices to reflect a more current fuel expense in this proceeding. The Commission concludes that the appropriate fossil fuel prices to be used are 1.779¢/kWh for coal and 8.170¢/kWh for oil, as recommended by the Public Staff.

The Company used unit fuel prices for the month of June 1986 applied uniformly to all units for its nuclear fuel prices, whereas the Public Staff used unit fuel prices based on the cost of the latest refueling for each nuclear unit. While the parties did not discuss at length this particular difference in their approaches to determining nuclear fuel prices, they do point out a potentially troublesome issue. Normalization of the unit fuel prices for nuclear fuel does appear to merit greater discussion in future proceedings.

The Company applied a systemwide unit fuel price to the normalized generation mix in order to determine total nuclear fuel costs, whereas the Public Staff applied a unit fuel price for each nuclear unit to the normalized generation mix in order to determine total nuclear fuel costs. The Public Staff contended that it would serve no useful purpose to establish an individual generating unit's normalized capacity factor and then apply a systemwide unit fuel price to said unit to obtain the total nuclear fuel cost for the unit, particularly when the unit fuel price for the individual generating unit is available.

The Commission concludes that nuclear fuel prices should be established in this proceeding based upon the Company's unit fuel price of 0.511¢/kWh for the month of March 1987 applied uniformly to the Brunswick units and to Robinson unit 2. The appropriate unit fuel price for the Harris unit is 0.595¢/kWh as proposed by the Company and as supported by the Public Staff. The Commission observes again that greater discussion of normalizing unit fuel prices for nuclear fuel does seem to be called for in future proceedings.

The Company excluded nuclear fuel disposal costs from its calculation of the base fuel component in its testimony, but included it at 1 mill/kWh in its proposed order. The Public Staff and the Attorney General both included nuclear fuel disposal cost at 1 mill/kWh in their calculations of the base fuel component. Just as the Commission did in the Duke Power Company general rate case in Docket No. E-7, Sub 408, the Commission concludes that it is reasonable and appropriate to include in the base fuel component the 1 mill disposal cost related to net nuclear generation. CP&L is now required to pay the Department of Energy 1 mill/kWh of nuclear generation for disposal costs related to nuclear generation. The nuclear fuel disposal costs (NFDC) are readily identifiable and vary directly with nuclear generation levels. The resulting nuclear unit fuel costs, including NFDC, which is appropriate for determining the fuel factor, are .511¢/kWh for the Robinson Unit 2, and Brunswick Units 1 and 2, and 0.595¢/kWh for Harris Unit 1.

The fuel calculation incorporating the conclusions made hereinabove is shown in the following table:

[Table below may extend beyond size of screen or contain distortions.(line lenth=73)]

UNIT	mW RATING	HRS	NORMALIZED CAPACITY FACTOR	mWh GENERATION	$/mWh	FUEL COST
ROBINSON 2	665	8760	63.460%	3,696,799	$ 5.11	$ 18,890,643
BRUNSWICK 1	790	8760	54.375%	3,762,968	$ 5.11	$ 19,228,766
BRUNSWICK 2	790	8760	51.610%	3,571,618	$ 5.11	$ 18,250,968
HARRIS 1	900	8760	70.000%	5,518,800	$ 5.95	$ 32,836,860
TOTAL NUCLEAR			60.07 %	16,550,185		$ 89,207,237
PUR.—CO-GEN				985,805	—	—
PUR.—SEPA				120,457		
PURCHASES—OTHER				183,299	$20.00	$ 3,665,980
HYDRO				722,343	—	—
COAL				20,108,455	$17.79	$357,729,414
IC				1,659	$81.70	$ 135,540
SALES				(357,706)	$17.32	$ (6,195,468)
TOTAL GENERATION/FUEL COST				38,314,497		$444,542,703

LESS:

POWER AGENCY NUCLEAR	$ 12,179,759
POWER AGENCY COAL	$ 18,385,046
MAYO BUYBACK	$ (3,915,810)
HARRIS BUYBACK	$ (2,551,586)
FUEL DOLLARS FOR FACTOR	$420,445,294
TOTAL kWh SALES FOR FACTOR	33,850,755,334
FUEL FACTOR (CENTS/kWh)	1.242

The Commission notes that a portion of the difference between fuel expense as presented by the Company and as presented by the Public Staff is due to the use of different methods for determining the North Carolina retail portion of total system adjusted fuel expense.

As can be seen from reviewing Carter Exhibit I, Schedules 3-1(a)(1) and 3-1(c)(1) Revised, the level of North Carolina retail fuel expense included in the cost of service by the Company of $307,487,000 excluding cogeneration is, for the most part, determined by allocating total system fuel expense by the E1 allocation factor. The E1 allocation factor reflects jurisdictional energy requirements at the generation level. Also, a portion of the Company's end-ofperiod level of North Carolina retail fuel expense is directly assigned. The Company's fuel annualization adjustment, which is found at TAB 7 of Item 10 of the E-1 Minimum Filing Requirements, directly assigns the adjustments to fuel expense associated with the Company's customer growth and weather normalization kWh sales adjustments.

The level of fuel expense proposed by the Public Staff in its testimony is determined by multiplying the Public Staff's proposed fuel factor by adjusted North Carolina retail kWh sales. This calculation is found in the testimony of Public Staff witness Durham and also in Carter Exhibit I, Schedule 3-1(c) Revised.

Although the issue of the appropriate method of determining North Carolina retail fuel expense was not explicitly raised by any of the parties to this proceeding, the Commission believes that the different methodologies used by the Company and the Public Staff should be addressed in this Order.

The Public Staff, in its proposed order in this docket, proposed a method of determining North Carolina retail fuel expense to be included in the cost of service by allocating total system adjusted fuel expense by the use of the E1 allocation factor resulting in fuel expense of $277,404,501.

The difference between the fuel expense calculated above and the North Carolina retail fuel expense presented by Public Staff witness Durham in his prefiled testimony of $274,999,463 is $2,405,038. This difference is due to the $277,404,501 being determined at the generation level and the $274,999,463 being determined at the meter level. For purposes of this proceeding the Public Staff has proposed that this $2,405,038 be treated as a "line loss differential" to be reflected in base rates rather than in the fuel factor.

As discussed previously, a portion of the Company's end-of-period level of fuel expense is directly assigned to the various jurisdictions. The Company directly assigned fuel cost associated with the customer growth and weather normalization kWh sales adjustments. The Commission has reviewed the Company's fuel annualization adjustment which incorporates these direct assignments of fuel cost. The Commission is not persuaded that the Company's adjustment is appropriate. The Company's adjustment assigns a higher level of fuel cost (1.578¢/kWh) to these adjustments than is actually reflected in the adjusted end-of-period level of fuel cost. The Commission finds cause not to accept the Company's direct assignment of certain fuel costs.

Consistent with prior Commission decisions, the Commission concludes that for the purposes of this proceeding, the appropriate level of North Carolina retail fuel expense to include in the cost of service is $270,641,000. This is determined by multiplying the fuel factor found herein to be appropriate of 1.242¢/kWh by adjusted North Carolina retail kWh sales of 21,790,765,728.

The Commission further concludes that both the Company and the Public Staff should investigate this matter more fully in the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence related to the appropriate level of coal inventory was presented by Company witness Nevil and Public Staff witness Durham. The Company included $48,219,000 for coal inventory in its working capital allowance. The Public Staff included in its working capital allowance $49,755,000 for coal inventory.

Both CP&L and the Public Staff recommended that coal inventory be established at an 80-day supply level, and both parties used similar methodologies in calculating their coal inventory values.

Witness Durham recommended a $76,436,633 investment allowance for coal on a systemwide basis, $49,754,531 for the North Carolina retail jurisdiction. His recommended 1,711,600-ton coal inventory level would provide an 80-day supply based on a 21,395ton daily burn rate. Witness Durham calculated the 21,395-ton daily burn rate using the same methodology adopted by this Commission in the Company's last general rate case and in the previous three Duke Power Company general rate cases. This method is based on the normalized coal generation utilized by the Public Staff to calculate fuel costs in this proceeding, plus the 10-year weighted-average fossil heat rate, the March 1987 cost per ton of coal, and the actual heat value of coal used by the Company.

The Commission concludes that the procedure used by the Public Staff is appropriate and, therefore, consistent with the coal generation found to be just and reasonable by the Commission under the Evidence and Conclusions for Finding of Fact No. 9, and also consistent with the jurisdictional cost allocations approved elsewhere herein the Commission concludes that a working capital allowance of $49,101,000 for coal inventory is appropriate for use in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting this finding of fact is included in the testimony and exhibits of Company witnesses Bradshaw and Nevil, and Public Staff witnesses Rankin and Durham. The amount of total working capital proposed by these witnesses as shown in their respective proposed orders is set forth in the following table:

[Table below may contain distortions.]

(000's Omitted)

Item	Company	Public Staff	Difference
Materials and supplies:			
Fuel stock	$ 53,818	$ 55,365	$ 1,547
Other materials and supplies	22,830	22,747	(83)
Minimum bank balances	2,234	2,205	(29)
Prepayments	8,166	8,060	(106)
Investor funds advanced for operations	30,822	30,727	(95)
Unamortized projects	4,968	4,920	(48)
Other rate base deductions	(12,981)	(12,750)	231
Customer deposits	(7,911)	(7,911)	—
Total working capital allowance	$101,946	$103,363	$1,417

The Company and the Public Staff are in agreement as to the appropriate amount of customer deposits to be deducted from rate base. Therefore, the Commission concludes that the amount of customer deposits to be deducted from rate base is $7,911,000.

The Public Staff adjustments to decrease minimum bank balances by $29,000, prepayments by $106,000, unamortized projects by $48,000, and other rate base deductions by $231,000 relate solely to the use of the cost of service study recommended by the Public Staff in this proceeding. As discussed in the Evidence and Conclusions for Finding of Fact No. 8, the Commission has adopted the use of the summer/winter peak and average method, as adjusted, for making jurisdictional cost allocations.

Based upon the use of such jurisdictional cost allocation methodology, the Commission concludes that the appropriate levels for these items are as follows: minimum bank balances—$2,203,000; prepayments $8,047,000; unamortized projects $4,918,000; and other rate base deductions -($12,733,000).

The next area of difference between the Company and the Public Staff with regard to working capital is the proper amount to be included in rate base for materials and supplies. The Company proposed a level of $76,648,000 for this item, while the Public Staff's recommendation would result in a level of $78,112,000. The difference of $1,464,000 results from the different proposed levels of coal inventory and also from the Public Staff's use of an adjusted summer/ winter peak and average method for making jurisdictional cost allocations. The chart below illustrates the components and respective positions of the Company and the Public Staff with respect to materials and supplies.

[Table below may contain distortions.]

(000's Omitted)

Item	Company	Public Staff	Difference
Fuel stock inventory:			
Coal	$48,219	$49,755	$1,536
Other liquid fuels	5,599	5,610	11
Other materials and supplies	22,830	22,747	(83)
Total materials and supplies	$76,648	$78,112	$1,464

Based on the Commission's determination in Finding of Fact No. 10, the appropriate working capital allowance for coal inventory for use in this proceeding is $49,101,000. As discussed in the Evidence and Conclusions for Finding of Fact No. 8, the Commission concluded that the summer/winter peak and average method, including the minimum system technique, as adjusted, is the appropriate method of making jurisdictional cost allocations. Therefore, the appropriate level of other fuel stock inventory is $5,596,000, and the appropriate level of plant materials and supplies is $22,747,000. The Commission concludes that the total level of materials and supplies of $77,444,000 is appropriate for use herein.

The next component of working capital on which the Company and the Public Staff disagree is in the area of cash working capital, represented by investor funds advanced for operations. CP&L determined in its proposed order that $30,822,000 should be included in working capital as investor funds advanced for operations, while the Public Staff included investor funds advanced for operations of $30,727,000.

Several adjustments proposed by the Public Staff were not contested by the Company and therefore require no discussion. Concerning investor funds advanced for operations, the three issues remaining among the parties relate to the proper allocation of cost of service to North Carolina retail operations, the proper federal income tax rate to be used in this calculation, and the appropriate lag for state income taxes.

Regarding the proper allocation factors to be used in this proceeding, the Commission in Finding of Fact No. 8, has adopted the summer/winter peak and average method, as adjusted, and it should therefore be incorporated in these calculations.

[15] To determine its proper level of cash working capital, the Company used a per books lead-lag study based on the March 31, 1986, test year. Public Staff witness Rankin proposed adjusting the lead-lag study to reflect the changes related to the Tax Reform Act of 1986. Specifically, witness Rankin proposed adjusting the per books lead-lag study to reflect the use of a 34% federal income tax (FIT) rate. The per books lead-lag study proposed by the Company used the 46% FIT rate which was in effect during the test year.

Under cross-examination, witness Rankin testified that a per books lead-lag study adjusted for significant changes was appropriate for determining cash working capital. She agreed that the Harris Plant and Brunswick Cooling Towers were also significant changes but argued that these would change the per books lead-lag study, and therefore she did not adjust for these items.

The Commission believes that it is inconsistent to adjust for one significant change such as the FIT rate and not for others such as Harris. Further, if the FIT rate change were adjusted for, the adjustment should be to a 40% rate rather than the 34% rate as discussed in Finding of Fact No. 15. The lead-lag study should be based either on an unadjusted per books lead-lag or a per books lead-lag adjusted for all significant changes. In this proceeding, the Commission finds that the per books leadlag study as proposed by the Company is appropriate for calculating cash working capital.

The final area of difference between the Company and the Public Staff in this regard, concerns the appropriate lag for state income taxes. The Company assigned a lag of 124.80 days to state income taxes, while the Public Staff assigned an 80.90 day lag. Public Staff witness Rankin testified that she revised the state income tax lag to reflect the Company's 1987 state income tax payment practice. She further testified that this revision to the state income tax lag reflects the Company's actual payment practice beginning in 1987 and therefore is more representative of current state income tax payment requirements. The Company agreed that this adjustment is more reflective of its 1987 payment practice.

The Commission agrees that the lag on state income taxes should be based upon the Company's actual payment practice in 1987 and concludes that the lag of 80.90 days, as assigned by public Staff witness Rankin, is the proper lag to use for state income taxes in this proceeding.

Based on all the foregoing, the Commission concludes that the appropriate level of investor funds advanced for operations to be included in rate base in this proceeding is $32,781,000.

In summary, the Commission concludes that the appropriate level of materials and supplies and working capital investment for use in this proceeding is $104,749,000, as shown in the following chart:

[Table below may contain distortions.]

(000's Omitted)

Item	Amount
Materials and supplies inventory:	
Coal	$49,101
Other liquid fuels	5,596
Other	22,747
Total materials and supplies inventory	77,444
Other working capital investment:	
Minimum bank balances	2,203
Prepayments	8,047
Investor funds advanced for operations	32,781
Unamortized projects	4,918
Other rate base deductions	(12,733)
Customer deposits	(7,911)
Total other working capital investment	27,305
Total working capital investment	$104,749

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

Company witnesses Smith, Bradshaw, and Nevil and Public Staff witnesses Carter, Rankin, and Durham presented testimony regarding CP&L's reasonable original cost rate base. The following table summarizes the amounts which the Company and the Public Staff contended in their proposed orders are the proper levels of original cost rate base to be used in this proceeding.

[Table below may contain distortions.]

(000's Omitted)

Item	Company	Public Staff	Difference
Electric plant in service	$3,988,473	$3,927,781	$(60,692)
Net nuclear fuel	123,483	123,741	258
Accumulated depreciation	(848,360)	(835,878)	12,482
Accumulated deferred income taxes	(391,173)	(432,695)	(41,522)
Allowance for working capital	101,946	103,363	1,417
Total original cost rate base	$2,974,369	$2,886,312	$(88,057)

The differences in electric plant in service, net nuclear fuel, and accumulated depreciation are all due to the Public Staff's use of an adjusted summer/winter peak and average method for jurisdictional cost allocation purposes.

As discussed in conjunction with the Evidence and Conclusions for Finding of Fact No. 8, Public Staff witness Lam proposed the use of the summer/winter peak and average method for making jurisdictional cost allocations. Use of this method accounts for $48,119,000 of the difference in electric plant in service between the Company and Public Staff. Additionally, Public Staff witness Haywood proposed certain adjustments to the summer/winter peak and average cost allocation study. These adjustments account for $12,573,000 of the remaining difference in electric plant in service. Similarly, use of the summer/winter peak and average method accounts for $10,058,000 of the difference in accumulated depreciation. The cost allocation adjustments proposed by Public Staff witness Haywood account for $2,424,000 of the remaining difference in accumulated depreciation and $258,000 of the difference in net nuclear fuel. Use of the summer/winter peak and average method did not, in itself, result in a change in net nuclear fuel.

In the Evidence and Conclusions for Finding of Fact No. 8, the Commission has adopted witness Lam's proposed use of the summer/winter peak and average method for making jurisdictional cost allocations and has readjusted the allocation factors adjusted by witness Haywood in regard to Power Agency to reflect the Commission's normalized generation level. Based on these decisions, the Commission finds that the Company's level of electric plant in service and accumulated depreciation should be reduced by $48,119,000 and $10,058,000, respectively, to reflect the change in cost allocation methodology (12CP versus SWPA). Further, the Commission concludes that the Company's proposed amounts should be additionally adjusted to reflect the effect of the change in allocation factors associated with Power Agency. The effect of these adjustments would result in a decrease of $16,708,000 in the level of electric plant in service, a decrease of $59,000 in the level of net nuclear fuel, and a decrease of $3,289,000 in the level of accumulated depreciation. Additionally, as discussed in the Evidence and Conclusions for Finding of Fact No. 14, the Commission concludes that accumulated depreciation should be increased by $1,067,000 to properly reflect the level of accumulated decommissioning expense associated with the Company's nuclear power plant units. Based on these conclusions, the Commission finds that the appropriate level of electric plant in service for use in this proceeding is $3,923,646,000. The Commission further concludes that the appropriate levels of net nuclear fuel and accumulated depreciation are $123,424,000 and $836,080,000, respectively.

The $1,417,000 difference in the allowance for working capital between the Company and the Public Staff was discussed in the Evidence and Conclusions for Finding of Fact No. 11. As discussed therein, the Commission concludes that the appropriate allowance for working capital for use in this proceeding is $104,749,000.

[16] The $41,522,000, difference in accumulated deferred income taxes (ADIT) is composed of the following adjustments proposed by the Public Staff:

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[Table below may contain distortions.]

(000's Omitted)

Item   Amount

Change in allocation method
  (12CP versus SWPA) $ 3,467
Change for Power Agency
  adjusted allocation method 1,143
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ADIT on sale to Power Agency (42,342)
Reversal of Company ADIT
  adjustment (5,148)
Adjustment to Harris ADIT 1,473
ADIT relating to nuclear
  decommissioning (67)
ADIT relating to Harris nuclear
  decommissioning (48)
    Total ADIT adjustments $(41,522)
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As discussed in the Evidence and Conclusions for Finding of Fact No. 8, the Public Staff proposed two changes concerning the appropriate cost allocation method. The use of the summer/winter peak and average cost allocation method proposed by Public Staff witness Lam accounts for $3,467,000 of the difference in ADIT between the Company and the Public Staff. The adjustments to the cost allocation study proposed by Public Staff witness Haywood account for $1,143,000 of the difference in ADIT. Since the Commission has previously found that the Public Staff's cost of service study and the Commission readjusted cost of service study reflecting the effect of the Commission's normalized generation on witness Haywood's adjustments are appropriate for use herein, the Commission concludes that it is appropriate to adjust ADIT by $4,919,000 to reflect the Commission's position on the adjusted summer/winter peak and average cost allocation method.

The next adjustment to ADIT in the amount of $42,342,000 relates to deferred taxes associated with the Company's sale of assets to the Power Agency. As discussed in the testimony of Public Staff witness Carter, this adjustment is the same adjustment that was proposed by the Public Staff and accepted by the Commission in CP&L's last two general rate cases. These deferred taxes are funds which CP&L has received from the Power Agency for tax liabilities of the Company which will not be paid until sometime in the future. Public Staff witness Carter stated that he did not believe that the North Carolina retail ratepayers should be required to pay a return on funds which were cost-free to the Company. Company witness Bradshaw, upon cross-examination, agreed that the adjustment was consistent with that made by the Commission in CP&L's last two general rate cases but indicated that he still disagreed with it.

The Commission discussed this issue at length in the Final Order entered in Docket No. E-2, Sub 481. The Commission concluded in that docket and also in Docket No. E-2, Sub 461, that it is appropriate to deduct these Power Agency related ADIT from rate base. The Commission continues to believe that this adjustment is appropriate for ratemaking purposes. These deferred taxes represent cost-free funds to the Company since the funds have been provided to CP&L by the Power Agency rather than by the Company's investors. If these deferred income taxes are not deducted from rate base, rates will be set to pay capital costs to cover interest expense, preferred dividends, and provide a common equity return on this amount of capital, even though this capital has no cost to CP&L whatsoever. The Commission concludes, therefore, that these deferred taxes should be treated as other cost-free capital to the Company and deducted from rate base. Based upon the adjusted cost of service study approved for use in this proceeding, the Commission finds that the proper adjustment relating to the deferred taxes associated with the Company's sale of assets to the Power Agency is $42,279,000 rather than the $42,342,000 proposed by the Public Staff.

The next difference between the Company and the Public Staff is the adjustment in the amount of $5,148,000 which Public Staff witness Carter made to reverse the Company's adjustment to ADIT for the Tax Reform Act of 1986 (TRA). The Company adjusted the test year balance in ADIT to reflect the level of ADIT that would have been on the books at the end of the test year (March 31, 1986) if the tax rate during the test year had been 40% rather than 46%.

Public Staff witness Carter disagreed with this adjustment. In reference to this adjustment, Mr. Carter testified as follows:

> While it is true that if the TRA had been in effect during the test year the ADIT balances would have been lower, the actual ADIT balance at the end of the test period will not change.

Mr. Carter further stated that:

> A lowering of the tax rate simply means that, in the future, ADIT balances will not be as large as they would have been had the tax rate not changed. A reduction in the tax rate will not affect deferred taxes that have already been recorded on the books.

Witness Carter agreed during cross-examination that he had adjusted deferred income tax expense to reflect a 34% federal tax rate and had also left ADIT, to be deducted from rate base, at the 46% rate at which those taxes had actually been deferred. When asked by counsel for the Company whether these two treatments were inconsistent, witness Carter testified that they were not inconsistent.

The Company maintains that the Public Staff position violates tax normalization and the matching concept of accounting. The Company argues that since tax expense is changed from the actual test year rate of 46% to the rate that will be in effect when rates established in this case are charged, consistency requires a matching adjustment to the ADIT reserve.

The Commission agrees with the Public Staff's position that these ADIT represent monies which the ratepayers have already paid in to cover a normalized level of tax expense. If this balance were not deducted from rate base, the Company's ratepayers would be forced to pay a return on money they have already provided to the Company. The basis for setting rates in a general rate case is by use of a historical test period. One necessary component in the ratemaking process is to determine a Company's original cost rate base. As stated in G.S. 62-133(c):

> The original cost of the public utility's property, including its construction work in progress, shall be determined as of the end of the test period used in the hearing and the probable future revenues and expenses shall be based on the plant and equipment in operation at that time.

Clearly in the ratemaking process, rate base should reflect actual booked costs as of a certain point in time plus, if appropriate, adjustments for changes in rate base after that point in time. The inclusion of a portion of the Harris Plant in rate base in this proceeding is a perfect example of the types of departures from end-of-period rate base which are contemplated in G.S. 62-133(c) which states:

> ... the Commission shall consider such relevant, material, and competent evidence as may be offered by any party to the proceeding tending to show actual changes in costs, revenues, or the cost of the public utility's property used and useful, or to be used and useful within a reasonable time after the test period ...

If one were to accept the Company's position on this matter, an argument could also be made to adjust other items of rate base to reflect prospective changes in cost. An example would be changes in the cost of debt. If one assumed that during the test year, while the Harris Plant was under construction, the Company's cost of debt was 10% and that the Company's cost of debt has since dropped to 8%, then an argument could be made to reduce the cost of the Harris Plant to reflect what the cost on the books would have been if the allowance for funds used during construction had been calculated using the 8% debt rate rather than the 10% debt rate.

The Commission concludes that the proper level of ADIT for use in this proceeding, at this juncture, is the actual balance reflected on the Company's books at March 31, 1986. To accomplish this result, the Public Staff's adjustment in the amount of $5,148,000 should be changed to an adjustment of $5,145,000 to reflect the Commission's adjusted cost allocation study. As will be discussed subsequently, the Commission has rejected the Public Staff's position regarding use of the 34% corporate federal income tax rate.

Further, the Commission notes that its treatment in this regard is consistent with decisions entered in Docket No. P-118, Sub 39, and P-10, Sub 115, to deny increases in rate base for pro forma adjustments to reduce ADIT when the prospective change in deferred taxes would not result in a decrease in the balance of ADIT at the end of the test year.

The remaining three adjustments to ADIT totaling $1,358,000 proposed by the Public Staff are corollary adjustments to adjustments made to deferred income tax expense. In making its $1,473,000 adjustment, the Public Staff agrees with the Company that an adjustment should be made to ADIT to reflect the prospective ADIT associated with the difference between Harris book and tax depreciation since there were no per books ADIT accounting for this difference. The Public Staff's adjustment of $1,473,000 in this regard merely adjusts for the use of a 34% federal income tax rate rather than a 40% federal income tax rate. The Public Staff's last two adjustments consisting of $67,000 and $48,000 to increase the amount of ADIT for nuclear decommissioning are also corollary adjustments which recognize increased deferred income tax expense due to changes in decommissioning expense over the test year levels. The Public Staff again agrees in concept with the Company's adjustments that when nuclear decommissioning expense and the associated reserve are increased then deferred income taxes and ADIT should be decreased, but because the Public Staff recommends the use of a 34% federal income tax rate rather than a 40% federal income tax rate the Public Staff would not decrease the deferred income taxes and ADIT as much as the Company had proposed. Since the Commission found in the Evidence and Conclusions for Finding of Fact No. 14 that the 40% federal income tax rate is appropriate for use in this proceeding as proposed by the Company, the Commission concludes that these Public Staff proposed corollary adjustments to ADIT are inappropriate for use in this proceeding. Further, based upon its decisions set forth in the Evidence and Conclusions for Finding of Fact No. 14, the Commission concludes that the level of ADIT should be decreased by $465,000 to properly reflect the level of decommissioning expense associated with the Company's nuclear power plant units.

Based on the preceding discussion, the Commission concludes that the appropriate balance of accumulated deferred income taxes to deduct from rate base in this proceeding is $433,213,000.

Company witness Smith testified that the cost of production plant includes for the first time approximately $126 million for the steam generator replacement at Robinson nuclear unit 2 and approximately $170 million for other nuclear plant costs including over $90 million for regulatory modifications at the Brunswick nuclear plant. He indicated that replacement of the steam generators at Robinson has resulted in the unit's continued excellent performance. The Brunswick modifications were required by the Nuclear Regulatory Commission (NRC). No witness refuted the cost effectiveness of such modifications. The Company's nuclear plants are all used and useful, and the Commission concludes that the nuclear plant costs described herein should be included in rate base.

The Commission concludes, based upon the foregoing and the determinations made in the Evidence and Conclusions for Findings of Fact Nos. 10 and 11, that the appropriate original cost rate base for use in this proceeding is $2,882,526,000 calculated as follows:

[Table below may contain distortions.]

(000's Omitted)

Item	Amount
Electric plant in service	$3,923,646
Net nuclear fuel	123,424
Accumulated depreciation	(836,080)
Accumulated deferred income taxes	(433,213)
Allowance for working capital	104,749
Total original cost rate base	$2,882,526

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Nevil and Public Staff witness Carter.

The appropriate level of gross revenues under present rates and after accounting and pro forma adjustments proposed by the Company is $1,325,877,000. The Public Staff proposed a level of $1,325,856,000.

The $21,000 difference between the parties is due solely to the Public Staff's use of an adjusted summer/winter peak and average method for jurisdictional cost allocation purposes. Use of the summer/winter peak and average method proposed by Public Staff witness Lam accounts for $6,000 of the difference. The adjustments to the summer/winter peak and average method proposed by Public Staff witness Haywood accounts for the remaining $15,000 difference.

Based on the Commission's determination, in conjunction with the Evidence and Conclusions for Finding of Fact No. 8, that an adjusted summer/winter peak and average cost of service study is appropriate for use in this proceeding, the Commission concludes that the appropriate level of gross revenues for use in this proceeding is $1,325,856,000.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14 AND 15

The evidence supporting these findings of fact is found in the testimony and exhibits of Company witnesses Bradshaw and Nevil, Public Staff witnesses Carter, Haywood, and Durham, and Attorney General witnesses Perkerson and Schlissel.

The following schedule sets forth the levels of operating revenue deductions as proposed by the Company and the Public Staff in their proposed orders:

[Table below may contain distortions.]

(000's Omitted)

Item	Company	Public Staff	Difference
Fuel and purchased power	$ 307,487	$ 277,405	$(30,082)
Other O&M expenses	486,140	462,389	(23,751)
Depreciation	151,602	149,142	(2,460)
Taxes other than income	76,601	76,122	(479)
Income taxes	79,801	86,689	6,888
Total operating revenue deductions	$1,101,631	$1,051,747	$(49,884)

As the schedule indicates, the parties are in disagreement on all the items of operating revenue deductions.

The difference between the parties proposed levels of fuel and purchased power expense was discussed in the Evidence and Conclusions for Finding of Fact No. 9. As was discussed therein, the Commission concludes that the appropriate level of fuel and purchased power expense is $270,641,000.

As has been discussed in the Evidence and Conclusions for Finding of Fact No. 8, some of the differences in the positions of the Company and the Public Staff are due to the Public Staff's use of an adjusted summer/winter peak and average method for jurisdictional cost allocation purposes. The following schedule itemizes the differences for each category of operating revenue deductions that are due to the Public Staff's use of a cost allocation method which is different from that proposed by the Company:

[Table below may contain distortions.]

(000's Omitted)

Item	Adjustment Due to Use of SWPA	Public Staff Adjustments to SWPA
Fuel and purchased power	$ —	$ 626
Other O&M expenses	(4,114)	(616)
Depreciation	(2,007)	(453)
Taxes other than income	(389)	(90)
Income taxes	3,397	371
Total adjustments	$(3,113)	$(162)

The Commission, having previously determined in the Evidence and Conclusions for Finding of Fact No. 8 that the summer/ winter peak and average cost of service study including the Commission's adjustments to Power Agency is reasonable and appropriate for use herein, concludes that the following adjustments to operating revenue deductions are appropriate for use in this proceeding:

[Table below may contain distortions.]

(000's Omitted)

Item	Adjustment Due to Use of SWPA	Commission Adjustments to SWPA
Fuel and purchased power	$ —	$ (143)
Other O&M expenses	(4,114)	(1,230)
Depreciation	(2,007)	(626)
Taxes other than income	(389)	(127)
Income taxes	3,397	1,128
Total adjustments	$(3,113)	$ (998)

The remaining difference in the level of other operation and maintenance (O&M) expenses is due to the following adjustments proposed by the Public Staff:

[Table below may contain distortions.]

(000's Omitted)

Item	Amount
Harris purchased capacity and energy	$ (5,420)
Mayo purchased capacity and energy	(1,248)
Harris levelization	(10,863)
Mayo levelization	(1,043)
EEI dues	(85)
MCF payment	(52)
Officers' salaries	(310)
Total other adjustments	$(19,021)

The first four adjustments listed above were discussed in the Evidence and Conclusions for Finding of Fact No. 6. As discussed therein, the Commission concludes that other O&M expenses should be adjusted as follows:

[Table below may contain distortions.]

Harris purchased capacity and energy	$ (4,505,000)
Mayo purchased capacity and energy	$ (1,173,000)
Harris levelization	$ (9,333,000)
Mayo levelization	$ (912,000)

[17] The next adjustment to other O&M expenses is an adjustment proposed by Public Staff witness Carter to disallow 40% of the Company's Edison Electric Institute (EEI) dues. Witness Carter testified that:

> It appears that many of the functions performed by EEI would fall into the category of lobbying if they were done by CP&L rather than EEI.

Witness Carter further testified that:

> Since CP&L excludes all of its lobbying expenses from the cost of service for ratemaking purposes, I believe it is reasonable to disallow similar expenses incurred by someone else on behalf of CP&L.

The Commission in Docket No. E-2, Sub 481 (CP&L's last general rate case), concluded that it was:

> ... appropriate for the Company in its next general rate proceeding to present information

which will show all direct and indirect contributions to and through EEI from all sources and all expenditures by program and by a system of accounts which will allow the Commission to specifically determine the appropriateness of the expenditures for ratemaking purposes.

The Commission finds that while the Company has provided additional information in this proceeding concerning EEI, the information provided is not sufficient to refute the position of the Public Staff. The Commission concludes, therefore, that the $85,000 reduction in other O&M expenses as proposed by the Public Staff is reasonable and appropriate for use herein.

The Commission notes also that in a Duke Power Company general rate case, Docket No. E-7, Sub 391, an adjustment to disallow 40% of EEI dues was also approved.

The next adjustment to other O&M expenses is an adjustment proposed by Public Staff witness Carter to disallow 50% of the Company's payment to EEI's Media Communications Fund (MCF). Witness Carter filed as Appendix A to his testimony, copies of certain ads sponsored by EEI. Based on a review of these ads which encourage consumption of power and also on the fact that the Company did not provide information regarding specific dollar amounts or present ads that would be appropriate for ratemaking purposes, the Commission concludes that the Public Staff's $52,000 adjustment to reduce the level of other O&M expenses is reasonable and appropriate for use herein.

The next adjustment to other O&M expenses proposed by the Public Staff is an adjustment to exclude from the cost of service 50% of the salaries and deferred compensation of the four Company officers who are members of the Executive Committee of the Board of Directors. As witness Carter pointed out in his testimony, similar adjustments have been proposed and approved in CP&L's last three general rate cases.

The Commission stated in the Final Order in CP&L's last general rate case, Docket No. E-2, Sub 481, that the issue of officers' salaries should be revisited in CP&L's next general rate proceeding for purposes of determining whether continuation of such an adjustment is appropriate. After careful consideration the Commission concludes that an adjustment to exclude 50% of officers' salaries and deferred compensation continues to be appropriate. The Commission finds that it is reasonable for the Company's shareholders to bear 50% of the salary and deferred compensation expense of the Company officers whose function is most closely linked with meeting the demands of the common shareholders. The Commission notes that this adjustment is also consistent with adjustments made in Duke Power Company's last two general rate cases, Docket No. E-7, Subs 391, and 408. Consistent with its findings on the appropriate cost of service study, the Commission concludes that an adjustment of $309,000 is appropriate rather than the $310,000 adjustment proposed by the Public Staff.

In making its determination of the appropriate level of other O&M expenses to be included in the Company's cost of service, the Commission finds that it is also appropriate to make one further adjustment resulting in an increase in the level of cogeneration expense proposed by the Company and the Public Staff to be included in base rates. As more particularly set forth in its Evidence and Conclusions for Finding of Fact No. 9, the Commission rejected the Company's proposal to shift the estimated fuel costs of cogeneration from base rates to the fuel factor at this time as the evidence in this proceeding shows that the fuel cost component of CP&L purchases from cogenerators which the Company proposed to include in the fuel factor is the estimated avoided fuel cost of the Company rather than an amount representing the embedded or actual fuel cost of the cogenerator.

The level of the energy and capacity components of CP&L's cogeneration costs for the test year in this proceeding, was $17,949,779 on a total system basis. CP&L made an adjustment of $29,240,653 on a total system basis to annualize to the end-of-period level the energy and capacity expenses related to cogeneration resulting in total system level of cogeneration costs of $47,190,432. CP&L's Fuel Report filed in Docket No. E-2, Sub 533, reflects a total system amount of $62,658,133 for the energy and capacity components of cogeneration costs for the 12 months ended March 1987.

In recognition of the fact that CP&L's cogeneration costs are escalating rapidly, the Commission believes that the level of the energy and capacity components of cogeneration costs for the 12-months ended March 1987 is a representative level of these costs and is the appropriate level to be included in the cost of service in this proceeding. Accordingly the North Carolina retail amount of O&M expense should be increased by $10,024,000 in this proceeding.

The Commission concludes, based upon the foregoing and the determinations made in Findings of Fact Nos. 6, 8, and 9, that the appropriate level of other O&M expenses for use herein, is $474,451,000.

As has been discussed previously in this Order, the differences between the levels of depreciation expense and taxes other than income proposed by the Company and the Public Staff are due to the Public Staff's use of an adjusted summer/winter peak and average method for jurisdictional cost allocations. Consistent with the Commission's determination of the appropriate cost of service study as discussed in the Evidence and Conclusions for Finding of Fact No. 8, the Commission concludes that the appropriate level of taxes other than income for use in this proceeding is $76,085,000. Further, the Commission finds that the level of depreciation expense proposed by the parties needs to be additionally adjusted to reflect the level of decommissioning expense associated with the Company's nuclear power plants calculated on the basis of the capital structure and cost rates approved by the Commission in this proceeding. In this regard, the Commission finds that the levels of decommissioning expense and the associated reserve level as proposed by the Company should be increased by $1,067,000. In conjunction with this adjustment, the Commission finds that it is also appropriate to decrease the levels of deferred income tax expense and accumulated deferred income taxes by $465,000. Consistent with its determination of the appropriate cost of service study as discussed in the Evidence and Conclusions for Finding of Fact No. 8 and its findings on decommissioning expense the Commission concludes that $150,036,000 is the appropriate level of depreciation expense to be used in this proceeding.

[18, 19] The final area of difference between the Company and the Public Staff in regard to the appropriate level of operating revenue deductions concerns the appropriate level of income tax expense to be used in this proceeding.

There are several reasons for the difference between the parties' proposed levels of income tax expense. Since the parties did not agree on the levels of the other items of operating revenue deductions, rate base, and revenues they, of course, would propose different levels of income tax expense. Additionally, the Public Staff's use of an adjusted summer/winter peak and average method for jurisdictional cost allocation purposes accounts for a portion of the difference in proposed income tax expense. The major difference between the parties' proposed levels of income tax expense, however, is due to the use of different federal income tax (FIT) rates.

Since the use of different federal income tax rates accounts for most of the difference in the parties' positions, the Commission will address this issue first.

Company witness Bradshaw testified that the appropriate federal income tax rate to use in this case is 40%, while Public Staff witness Carter and Attorney General witness Perkerson testified that the appropriate rate is 34%.

Company witness Bradshaw, who recommended the use of a 40% federal income tax rate, opposed the use of a 34% federal income tax rate for two reasons. He testified as follows:

> First, there are certain mandatory normalization provisions that using the 34% tax rate could violate. Secondly, using the 34% tax rate in this case frustrates the Company's attempt to moderate the increase in customers' rates by phasing in the Harris Plant over two rate cases.

Witness Bradshaw further testified that if a 34% rate were used, it would clearly fall below the actual tax rate for calendar year 1987 of 40%, and that if tax expense in the cost of service were provided at any rate less than 40%, the deferred taxes applicable to accelerated depreciation may not be sufficient to establish compliance with the mandatory normalization rules of the Internal Revenue Code.

Witness Bradshaw testified that the use of a 34% federal income tax rate would also frustrate the Company's attempt to phase in the Harris Plant over two rates cases, and that the attempt to lessen the impact from Harris on customer bills may be easily frustrated if the Commission recognizes the reduction in tax expense caused by the Act in a manner that passes all of the benefits along to the customers as a reduction in rates in this case.

In order to preserve for customers the advantages of the phase-in scenario and at the same time recognize in rates the reduction in the federal income tax rate, witness Bradshaw submitted the following proposal: (1) Establish rates in this case based upon a federal income tax rate of 40%. (2) Establish a second reserve account beginning January 1, 1988, for revenues representing the difference between rates based on a 40% federal income tax rate and those based on a 34% federal income tax rate. (3) In the Company's 1988 rate case make an adjustment to flow through the funds maintained in both reserve accounts as a reduction in rates established in that case. Such adjustment should be established for a one-year period. Witness Bradshaw also testified that these reserve accounts should accrue interest at a rate set by the Commission. The Company stated that it is willing to voluntarily forego the revenues it legitimately collected between January 1, 1987, and August 5, 1987 only if the Commission accepts the other aspects of its proposal for recognizing the reduction in the FIT rate.

Witness Bradshaw stated that if the Company's proposal is followed, customers would receive the full benefit of the reduction in the tax rate, and the beneficial value of the Harris phase-in would be preserved. In addition, CP&L's proposal would avoid the potential loss of accelerated depreciation if rates are established in this case as though the federal income tax rate were only 34%.

Public Staff witness Carter testified that the federal income tax component of the cost of service in this proceeding should be based on a federal income tax rate of 34%, but that CP&L should continue to expense federal income taxes on its books for the remainder of 1987 using the blended rate of 40%. Witness Carter also testified that if the 34% federal income tax rate is used to determine the level of federal income tax expense in this proceeding, the deferred account required by the Commission's Order entered in Docket No. M-100, Sub 113, to record the difference between the 46% federal income tax rate and the 40% federal income tax rate should be reversed. He further stated that if the Commission agrees with his recommendation that the 34% rate is the appropriate rate to use in this proceeding, there will be no need for a second deferred account in 1988 to reflect the difference between the 40% and 34% federal income tax rates.

Witness Carter testified that the use of the 34% federal income tax rate, which became effective on July 1, 1987, would not violate the normalization requirements of the Internal Revenue Code. Witness Carter stated that as long as CP&L multiplied the difference between depreciation expense for income tax purposes and depreciation expense for book purposes by the blended federal income tax rate of 40% for 1987 and added that amount to the balance of accumulated deferred income taxes there would be no chance whatsoever that CP&L would be in violation of the Internal Revenue Code normalization requirements.

On cross-examination, witness Carter was asked whether it would be inconsistent to use the 34% federal income tax rate for the purpose of determining net operating income for return in setting rates in this proceeding and at the same time to deduct the actual per books accumulated deferred income taxes at the end of the test period when amounts had been added to that reserve during the test period at the 46% federal income tax rate. Witness Carter testified that this would not be inconsistent and that it is entirely appropriate to do so. This issue was fully discussed in conjunction with the Evidence and Conclusions for Finding of Fact No. 12. As determined therein, the Commission agrees with witness Carter that his treatment of accumulated deferred income taxes is reasonable and proper.

Witness Carter strongly emphasized that he was recommending that the Commission use the federal income tax rate of 34% in determining the appropriate level of federal income tax expense in this proceeding. However, he testified that if the Commission is persuaded that the 40% rate is the appropriate rate to use in this proceeding, he would then make the following recommendations:

(1) The Commission should determine a revenue requirement using a 40% tax rate; this revenue requirement should be reflected in rates as soon as an Order is issued in this proceeding.

(2) The Commission should calculate a second revenue requirement using a 34% tax rate; rates should be reduced effective January 1, 1988 to reflect this revenue requirement.

(3) The Commission should require the Company to file two sets of tariffs; one reflecting the revenue requirement based on the 40% tax rate and one reflecting the revenue requirement based on the 34% tax rate.

(4) The Commission should require CP&L to file, within 30 days of the date an Order is issued in this proceeding, a plan to refund the amounts recorded in the deferred account from January 1, 1987, until the date that rates set in this proceeding go into effect. The Commission should require the Company to refund these excess tax collections, with interest, as soon as possible.

Attorney General witness Perkerson testified that the appropriate federal income tax rate to use in this proceeding is 34%, and that the use of the 34% federal income tax rate would not violate Internal Revenue Code normalization requirements. Witness Perkerson stated that the difference between the 46% federal income tax rate and the 34% federal income tax rate from July 1, 1987, through the date of the Order in this proceeding should be refunded to CP&L's customers in the form of a onetime credit to their monthly bills. It is the opinion of witness Perkerson that either the Company's argument with respect to normalization is correct and CP&L has already knowingly violated normalization requirements due to its charging of tariffs using a federal income tax expense of 46% while booking taxes at a blended effective rate of 40%, or the Company's argument is incorrect, and neither the Company's actions nor the Commission's actions in using a 34% statutory federal income tax rate for some other utilities violates normalization. Witness Perkerson is of the opinion that the Company's normalization argument is definitely incorrect.

CUCA in its proposed order, supports the position taken by the Public Staff and the Attorney General that the cost of service in this proceeding should reflect a 34% federal income tax rate. Further, CUCA recommends that a onetime refund computed by the difference between the 46% FIT rate and the 40% FIT for the first 8 months of 1987 be made in the Company's September 1987 bills including interest on the refund.

After careful consideration of the positions of all parties, the Commission makes the following findings in this regard:

(1) It is appropriate to fix rates in this proceeding based upon the use of a 40% FIT rate in the cost of service;

(2) It is appropriate to require a refund with interest of the January 1, 1987, through August 5, 1987, accumulated balance of the first deferred account established in Docket No. M-100, Sub 113, which tracked the difference in revenues billed under rates reflecting a 46% FIT rate and

revenues that would have been collected if rates had been based upon a 40% FIT rate; and

(3) It is appropriate that CP&L establish a second deferred account as of January 1, 1988, in which to accrue the difference between revenues billed under approved rates reflecting a 40% FIT rate and revenues that would have been billed if rates had been determined based upon a 34% FIT rate.

The Commission agrees that the Company's tax rate proposal ensures that the customers will in fact receive the full benefit of the reduction in the federal income tax rate, while the Public Staff's proposal of a 34% FIT rate with no refund does not. The primary advantage of the CP&L proposal is that customers will receive the benefit of the reduction in the FIT rate from 46% to 40% for the first seven months of 1987 and also, as discussed below, that it can serve as a mechanism to help phase the Harris Plant into rates. Public Staff Bradshaw Cross-Examination Exhibit 2A illustrates the fact that under the CP&L proposal this benefit exceeds approximately $6 million. Under the Public Staff's proposal, the benefit to customers is significantly less. Since there would be a delay in customers receiving the full benefit in the FIT rate reduction under the CP&L proposal, CP&L has agreed to pay interest on the balance in the deferred account. Consequently, the customers' interests would be fully protected under CP&L's plan.

In addition to the Company's concern about the federal tax laws as they affect normalization, CP&L is motivated by a desire to foster a phase-in of the rate increases that will take place during 1987 and 1988. CP&L argues that its approach is more appropriate and more consistent with the Commission's Order in Docket No. E-2, Sub 511, rather than one smaller increase followed shortly by a substantially larger increase.

The Public Staff's alternative proposal, unlike its official or preferred proposal, also ensures customers the full advantage of the federal tax reduction. However, if adopted, in total, the effect of the Public Staff alternative FIT rate adjustment is to offset the increase in this case, cause a rate reduction on January 1, 1988, and tends to magnify the magnitude of the general rate increase expected later in 1988. The Commission concludes that rates should be set in this proceeding to reflect a 40% FIT rate which is the 1987 calendar year rate and that during the 12 months beginning August 5, 1987, the first deferred account balance for the difference between the 46% FIT rate and the 40% FIT rate should be refunded to CP&L's customers plus interest. Further the Commission notes in its Order issued in this docket on August 5, 1987, that CP&L is placed on notice that it will be required to refund income tax expense overcollection plus interest, once it has occurred and once the exact amount can be determined, which will arise as a result of the change in the federal income tax rate from 40% to 34%.

CP&L further argued that the proposals made by the Public Staff and Attorney General, if adopted, would risk loss to CP&L of the advantages of tax normalization which witness Bradshaw testified could result in an increase of approximately $100,000,000 in the Company's current tax liability in 1987.

Section 167(1)(3)(G) of the Internal Revenue Code states:

(G) NORMALIZATION METHOD OF ACCOUNTING.—In order to use a normalization method of accounting with respect to any public utility property—

(i) the taxpayer must use the same method of depreciation to compute both its tax expense and its depreciation expense for purposes of establishing its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account, and

(ii) if, to compute its allowance for depreciation under this section, it uses a method of depreciation other than the method it used for the purposes described in clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from the use of such different method of depreciation.

CP&L computes depreciation expense for tax purposes through an accelerated method of depreciation and for book and ratemaking purposes through the straight line method of depreciation. Consequently, CP&L must establish a reserve to record the difference due to differences in depreciation methodology.

Under the proposals of the Public Staff and Attorney General, subsequent to August 5, 1987, CP&L would compute taxes at 40% for tax return and book purposes but at 34% for ratemaking purposes. As a result, CP&L argues that the deferred taxes added to the accumulated deferred income tax reserve will reflect less than "the deferral of taxes resulting from the use of different methods of depreciation" as Section 167(1)(3)(G)(ii) requires. The Attorney General and Public Staff argue that this section of the tax code deals primarily with differences in depreciation methods. CP&L asserts that the provisions of the tax code stress differences in tax expense flowing from differences in depreciation expense not differences in depreciation expense itself.

Both Public Staff witness Carter and Attorney General witness Perkerson recommend that CP&L should continue to accrue taxes on its books at 40% even though the tax rate the Commission should approve for ratemaking purposes will be 34%. The Public Staff argues that as long as the per books tax rate is 40% or the same as the effective tax rate, "there is no chance, whatsoever, that the Company will be in violation of the Internal Revenue Code normalization provisions."

In view of the fact that the Commission has hereinabove previously concluded that a 40% FIT rate is the appropriate tax rate for use in this proceeding, the Commission does not find it necessary to decide the Company's normalization argument. The Commission concludes that the Company should refund the funds collected in the first deferred account established in Docket No. M-100, Sub 113, which tracked the difference between revenues billed under rates reflecting a 46% FIT rate and revenues that would have been collected if rates had been based upon a 40% FIT rate. Such refund should be made during the 12-month period beginning August 5, 1987. The Commission hereby directs the Company to establish a second deferred account effective January 1, 1988 to record the difference between revenues billed under approved rates reflecting a 40% rate and revenues that would have been collected if rates had been determined based upon a 34%

FIT rate. Interest shall accrue on both deferred accounts at the rate of 10% per annum.

The difference in income tax expense that is due to the use of the summer/winter peak and average allocation method advocated by Public Staff witness Lam is $3,397,000. The adjustments to the summer/winter peak and average allocation method proposed by Public Staff witness Haywood account for $371,000 of the difference in income tax expense. Having previously discussed the appropriate cost of service study for use herein, the Commission now concludes that it is appropriate to increase the Company's proposed level of income tax expense by $4,525,000. Further, in conjunction with its findings regarding decommissioning expense, the Commission finds that it also appropriate to decrease deferred income tax expense by $465,000.

Based upon the Commission's determinations regarding the appropriate jurisdictional allocation method, the appropriate federal income tax rate and the appropriate levels of rate base, revenues, and operating revenue deductions the Commission hereby concludes that the appropriate level of income tax expense for use in this proceeding is $103,436,000, including deferred investment tax credits and deferred income taxes.

[20] One further operating revenue deduction issue concerning the appropriate ratemaking treatment of abandonment losses will now be addressed. The Attorney General challenged the Company's proposed ratemaking treatment of the abandonment losses relating to Harris Units 2, 3, and 4. Company witness Bradshaw testified that CP&L has abandoned several projects since 1979. He testified that two such abandonments, the South River project and the Brunswick Cooling Towers, have already been amortized pursuant to Commission Orders and are not included in the rates proposed for this case. Another abandonment, Mayo Unit 2, will be considered in CP&L's next general rate case pursuant to the Commission's Order of June 16, 1987. Witness Bradshaw testified that the Company's proposed cost of service in this case includes the amortization of losses relating to the abandonment of Harris Units 2, 3, and 4. Witness Bradshaw filed an exhibit reflecting $32,545,050 as the North Carolina retail revenue requirement for these Harris abandonment losses when calculated at CP&L's proposed 40% federal income tax rate.

The ratemaking treatment of the Harris abandonment losses has been considered by the Commission in previous general rate cases of CP&L. In Docket No. E-2, Sub 444, the Commission allowed a recovery of the cost associated with cancelled Harris Units 3 and 4 over a 10-year period with inclusion of the interest arising from the debt financing portion of the unamortized balance. In Docket No. E-2, Sub 461, the Commission reexamined the ratemaking treatment of abandonment losses in order to develop a more consistent and equitable approach. The Commission determined that CP&L should be allowed to continue amortization of the Harris abandonment losses, but that no ratemaking treatment should be allowed which would have the effect of allowing CP&L to earn a return on the unamortized balance. The Commission concluded that this treatment provided the most equitable allocation of the loss between the utility and its ratepayers. In CP&L's last general rate case, Docket No. E-2, Sub 481, the Commission dealt with CP&L's decision to cancel the construction of Harris Unit 2. Consistent with its treatment of the earlier Harris cancellations, the Commission ruled that the abandonment losses of Harris Unit 2 should be amortized over ten years with no return allowed on or with respect to the unamortized balance. Consistent with these previous orders, CP&L proposes in this case to include in operating expenses the amortization of the three abandoned Harris units.

The Attorney General opposes any recovery of the abandonment losses through rates in this case. The Attorney General argues that the abandoned plant costs cannot be included in rate base since they do not relate to plant "used and useful" in providing service. The Commission has not included these costs in rate base. The Commission has instead allowed CP&L to recover the abandonment costs over time through amortization of these costs as operating expenses. The Attorney General argues that such ratemaking treatment is improper because abandonment losses do not constitute operating expenses and because operating expenses must have the same nexus with the test year and "used and useful" concepts as must rate base. The Attorney General cites a 1981 decision of the Ohio Supreme Court holding that the losses associated with certain cancelled nuclear plants in that state could not be amortized as expenses for ratemaking purposes under the Ohio statutes. Office of Consumer Council v. Ohio Pub. Utilities Commission, — Ohio St.2d —, 423 N.E.2nd 820 (1981).

Initially, the Commission notes that the majority of courts and commissions that have dealt with this issue have allowed ratemaking treatment of abandonment losses, usually as operating expenses. Each of these cases, including the case cited by the Attorney General was decided on the basis of the statutes in the jurisdiction involved. The Commission cites them as an indication of the situation in other jurisdictions. This case must of course be decided on the basis of the North Carolina statutes. The Commission interprets these statutes as allowing the ratemaking treatment previously ordered for the Harris abandonments. When both the decision to build a generating plant and the subsequent decision to cancel it are prudent, the Commission believes that it is just and reasonable to allow amortization of the abandonment losses as operating expenses.

The Attorney General first argues that these abandonment losses represent capital expenditures not operating expenses. Operating expenses, it is argued, are "the more ordinary, out-of-pocket expenditures which represent the utility's cost of providing service." Furthermore, the Attorney General cites G.S. 62-133(c) to argue that all operating expenses must be "based on the plant and equipment in operation at [the end of the test period]." It is argued that there must be a nexus between operating expenses and specific property in operation devoted to serving the public. The Commission declines to take such a strict view of the ratemaking treatment authorized for operating expenses.

Initially, the Commission notes that the term "operating expenses" is neither defined by our statutes nor subject to a generally accepted meaning as a term of art. Our Supreme Court has considered the scope of the term as used in our ratemaking statute. North Carolina Utilities Commission v. Edmisten, 294 N.C. 598, 606 (1978), holds, "When a narrow construction of the operating expense element of a regulatory act would frustrate the purposes of the act, however, the term should be liberally interpreted and applied." In that case the Supreme Court, looking to the purposes behind the Public Utilities Act, upheld the Commission's treatment of the reasonable costs of approved gas exploration projects as operating expenses. The Court held, "if no new supply source were obtained, the utilities would be unable to supply adequate service to their customers and severe repercussions to the economy of the State would ensue. In such a situation, the costs of these projects, handled as outlined above, must be said to be operating expenses if practical effect is to be given the Act." Id., 294 N.C. at 607.

The purposes of the Public Utilities Act, as set forth in G.S. 62-2, include the promotion of adequate, reliable, and economical utility service and assurance "that facilities necessary to meet future growth can be financed by the utilities operating in this State on terms which are reasonable and fair to both the customers and existing investors of such utilities." The Commission has previously determined that our treatment of these abandonment losses is necessary in order to promote an equitable sharing of the loss between the ratepayers and the utility stockholders. This was based upon a 1983 study by the U. S. Department of Energy entitled Nuclear Plant Cancellations: Causes, Costs and Consequences which was introduced in evidence in CP&L's last general rate case and which was cited in our order in that rate case. Thus, the Commission concludes that a liberal interpretation of the operating expense element of ratemaking so as to include the Harris abandonment losses is appropriate herein.

The Commission is not persuaded that G.S. 62-133(c) requires the strict nexus argued for by the Attorney General. Many reasonable operating expenses cannot be tied to specific utility property. Examples include load management, system planning, research and development, as well as the gas exploration costs involved in the Supreme Court case cited above.

Further support for the Commission's conclusion is provided by S.G.S. 62-133(d). This section of the statute provides that the Commission "shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." All sections of G.S. 62-133 must be given weight in fixing rates. "By the adoption of this statute, the legislature intended to establish an overall scheme for fixing rates, and it must be interpreted in its entirety in order to comply with the legislative intent." North Carolina ex rel. Utilities Commission v. Duke Power Co., 305 N.C. at 12. Taking the statute as a whole, and with a view to the purposes of the Public Utilities Act, the Commission finds its previous treatment of the Harris abandonment losses to be just and reeasonable and reaffirms that treatment herein.

Based upon all of the foregoing, the Commission concludes that the appropriate level of total operating revenue deductions for use in this proceeding is $1,074,649,000, calculated as follows:

[Table below may contain distortions.]

(000's Omitted)

Item	Amount
Fuel and purchased power	$ 270,641
Other O&M expenses	474,451
Depreciation	150,036
Taxes other than income	76,085
Income taxes	103,436
Total operating revenue deductions	$1,074,649

One final deduction in determining net operating income for return is interest on customer deposits. The Company and the Public Staff both agreed that the appropriate level is $552,000. The Commission concludes, therefore, that $552,000 of interest on customer deposits should be deducted from operating income before adjustments in order to determine net operating income.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 16

The evidence for this finding of fact regarding depreciation is found in the testimony of Company witness Bradshaw and Public Staff witness Turner.

Witness Bradshaw presented the Company's proposed level of depreciation expenses for nuclear production plant based on depreciation rates previously approved in Docket No. E-2, Sub 416, at 4.0144%.

Witness Turner discussed the basis for the 4.0144% nuclear depreciation rate, and contended that a rate of 3.2% might result if the net plant balance is recovered over the remaining life of the Robinson and Brunswick units (provided their remaining lives are governed by the expiration dates of their operating licenses issued by the Nuclear Regulatory Commission). However, witness Turner proposed no adjustment to the 4.0144% rate and pointed out that the Company currently has a study underway reviewing depreciation rates and expects to have its study completed in time for its next general rate case. He recommended that the Company be required to file a completed depreciation study with its next rate case.

The Commission is of the opinion that the Public Staff's recommendation should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 17

[21, 22] The evidence relating to this finding of fact is presented in the testimony and exhibits of Company witnesses Bradshaw and Vander Weide, Public Staff witness Sessoms, CUCA witness Bowyer, and Attorney General witness Smith. The following chart summarizes the positions of the parties regarding the appropriate capital structure for use in this proceeding:

[Table below may contain distortions.]

	CP&L	Public Staff	CUCA	Attorney General
Long-term debt	48.50%	48.84%	48.52%	48.50%
Preferred stock	8.50%	8.36%	10.27%	8.50%
Common equity	43.00%	42.80%	41.21%	43.00%
Total	100.00%	100.00%	100.00%	100.00%

In its application, as reflected in the prefiled testimony and exhibits of Company witnesses Bradshaw and Vander Weide, the Company utilized a pro forma or normalized capital structure estimated by adjusting the July 1986 actual capital structure for changes anticipated to occur through March 1987. This capital structure contained 43.00% common equity. In its application, the Company also utilized pro forma cost rates for debt of 8.90% and for preferred stock of 8.87%. Company witnesses Vander Weide and Bradshaw recommended that the Commission should approve a normalized capital structure in this case consistent with the Commission's practice in past CP&L cases. Company witness Bradshaw, under cross-examination, also indicated that CP&L's actual equity capitalization ranged from 42.8% to 44.14% during the January 1987—May 1987 period.

In supplemental testimony filed on June 1, 1987, Company witness Bradshaw updated the Company's requested embedded cost rates for debt and preferred stock to equal 8.81% and 8.74%, respectively. He testified that these were the Company's actual embedded cost rates at April 30, 1987, adjusted for redemption premiums and the unamortized discount and issuance expenses. However, Mr. Bradshaw continued to recommend the pro forma capital structure requested in the Company's application.

Public Staff witness Sessoms recommended that the Commission should employ the latest known and actual quarter ending capital structure and embedded cost rates of CP&L. As of March 31, 1987, the actual capital structure of CP&L consisted of 48.84% long-term debt, 8.36% preferred stock, and 42.80% common equity. The embedded cost rates for long-term debt and preferred stock were 8.81% and 8.89%, respectively, as of that same date. Witness Sessoms testified that a pro forma capital structure should not be employed unless the actual capital structure is unreasonable. He also testified that the Company's requested pro forma capital structure and embedded cost rates at the end of April 1987 would result in an increased revenue requirement of $582,000 in this case greater than would the Company's actual capital structure and embedded cost rates as of March 31, 1987.

CUCA witness Bowyer recommended in his prefiled testimony that the pro forma capital structure and pro forma embedded cost rates originally requested by the Company should be employed for ratemaking purposes. However, in his summary, witness Bowyer changed his recommended capital structure and embedded cost rates. He testified that he had updated the costs of debt and preferred stock and had employed an actual capital structure provided by the Company. Therefore, he recommended a capital structure consisting of 48.52% long-term debt, 10.27% preferred stock, and 41.21% common equity. The embedded costs of debt and preferred stock which he employed were 8.81% and 8.74%, respectively.

On cross-examination, it was established that witness Bowyer's recommended capital structure was that of CP&L at March 31, 1986, the end of the test year, and the embedded costs were those as of April 30, 1987.

Attorney General witness Smith recommended the pro forma capital structure requested by the Company consisting of 48.5% long-term debt, 8.5% preferred stock, and 43.0% common equity. Dr. Smith also recommended that the pro forma embedded cost rates of debt and preferred stock originally requested by the Company, which were 8.90% and 8.87%, respectively, should be employed for ratemaking purposes.

The fact that CP&L's actual equity capitalization has recently fluctuated generally above the requested level of 43.0 percent supports the use of the Company's pro forma capital structure. The Commission also approved a normalized capital structure for CP&L in the Company's last general rate case, Docket No. E-2, Sub 481. The Commission believes that the normalized capital structure proposed by CP&L in this case which contains a 43.0% equity component is reasonable for ratemaking purposes, particularly when considered in combination with the rate of return on common equity allowed herein. Accordingly, the Commission finds and concludes that the reasonable and appropriate capital structure for CP&L in this proceeding is a normalized capital structure as follows:

[Table below may contain distortions.]

Item	Percent
Long-term debt	48.5%
Preferred stock	8.5%
Common equity	43.0%
Total	100.0%

Regarding the cost rates for long-term debt and preferred stock, all parties, except the Public Staff, agree with the Company's update of such costs as of April 30, 1987, as follows:

[Table below may contain distortions.]

	Company Filed	Company Amended	Public Staff
Long-term debt	8.90%	8.81%	8.81%
Preferred stock	8.87%	8.74%	8.89%

The Public Staff used cost rates for longterm debt and preferred stock that were the actual per book values as of March 31, 1987. In his proposed order, the Attorney General supports adoption of CP&L's updated cost rates as of April 30, 1987, for both long-term debt and preferred stock.

The Commission concludes that the reasonable and appropriate embedded cost rates for long-term debt and preferred stock to be used in this proceeding are the updated April 30, 1987, cost rates of 8.81 percent and 8.74 percent, respectively.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 18

The evidence supporting this finding of fact is found in the testimony and exhibits of Company witness Vander Weide, CUCA witness Bowyer, Attorney General witness Smith, and Public Staff witness Sessoms.

To determine his recommended cost of common equity, Dr. Vander Weide conducted a discounted cash flow (DCF) analysis and a risk premium analysis. The result of his DCF analysis was 12.4%. His risk premium result was 13.5% to 14.5%. Therefore, Dr. Vander Weide concluded that the cost of common equity for CP&L was in the range of 12.4% to 14.5%. He recommended a return on common equity in the upper end of this range of 14.0%. His decision to recommend a result at the upper end of this range was based on his belief that the Commission did not increase the allowed rate of return step for step with the rapid increase in actual capital costs which occurred during the 1970's and early 1980's and therefore should react only gradually to decreases in capital costs.

Dr. Vander Weide was questioned extensively concerning his concept of gradualism and specifically about how his cost of equity recommendation in this case compared to prior recommendations he has made before this Commission. He agreed that in previous cases he had used the risk premium method only as a check for his DCF results. Public Staff Cross Examination Exhibit No. 1 showed that in his last five appearances before this Commission as a cost of equity witness, Dr. Vander Weide's final recommendation was within 25 basis points of his DCF results in every one of those cases. In the present case, however, his final recommendation of 14.0% is 160 basis points above his prefiled DCF result of 12.4% and 240 basis points above an updated DCF result of 11.6%. When asked to explain this inconsistency, Dr. Vander Weide testified that he used judgment in all cases and that present circumstances differed from those in the past.

Dr. Vander Weide employed the quarterly version of the DCF Model with respect to CP&L alone and did not establish a group of comparable risk companies. The dividend yield was calculated by dividing the dividend in the S&P Stock Guide of September 1986 by the average of the high and low stock prices over the three month period August through September 1986. The price was adjusted by 5.0% to account for flotation costs and market pressure. The growth component was taken directly from the September 1986 edition of the Institu tional Brokers Estimate System (IBES). The adjusted dividend yield was combined with the IBES growth rate, and the sum was then annualized to arrive at a cost of common equity equal to 12.4% for CP&L using this approach.

Dr. Vander Weide was asked several questions under cross-examination about his DCF analysis. He testified under crossexamination that his DCF result of 12.4% would equal 11.6% if updated. He also agreed that the 5.0% flotation cost and market pressure adjustment to the stock price of CP&L caused his DCF result to be .43% (or 43 basis points) higher than if the stock price had not been adjusted. Public Staff Cross Examination Exhibit No. 3 showed that a .43% increase in the allowed return on common equity would result in annual North Carolina retail revenue requirements being $9,954,000 higher. Public Staff Cross Examination Exhibit No. 2 showed that CP&L has incurred only $2,260,000 for flotation costs over the last six years. However, Dr. Vander Weide stated that the $2,260,000 figure did not reflect costs such as market pressure printing and legal expenses.

Dr. Vander Weide's risk premium result of 13.5% to 14.5% was derived by adding a 4.0% to 5.0% risk premium to the expected yield on long-term debt issues of CP&L of around 9.5%.

Concerning his risk premium approach, Dr. Vander Weide was cross-examined extensively on any change in risk premiums that may have occurred in recent years. He agreed that risk premiums have been lower recently than over the long term. In his opinion, this was due to higher return requirements demanded by bond investors as a result of the unexpected inflation that occurred during the late 1970's and early 1980's. Dr. Vander Weide also agreed that interest rates have fluctuated dramatically since 1979 and have remained relatively high compared to historical levels prior to 1979. As this higher return requirement suggests, Dr. Vander Weide concurred with counsel that investors now perceive longterm bonds as being riskier than prior to 1979. However, he disagreed that lower risk premiums were appropriate at the current time because stock returns have also fluctuated. When questioned about short-run fluctuations, Dr. Vander Weide agreed that the volatility of common stock returns since 1980 has been much like the long-run volatility of returns of common stocks. In his direct testimony, Dr. Vander Weide cites an article by Brigham, Shome, and Vinson published in the Spring, 1985 edition of Financial Management that states:

> The effects of changing interest rates in risk premiums shifted dramatically in 1980, at least for the utilities. From 1965 through 1979, inflation generally had a more severe adverse effect on utility stocks than on bonds, and, as a result, an increase in inflationary expectations, as reflected in interest rates, caused an increase in equity risk premiums. However, in 1980 and thereafter, rising inflation and interest rates increased the perceived riskiness of bonds more than that of utility equities, so the relationship between interest rates and utility risk premium shifted from positive to negative.

The article concludes by noting the instability of risk premiums and questioning FERC and FCC proposals of using a risk premium method to determine a utility's cost of equity.

CUCA witness Bowyer recommended that CP&L should be allowed an 11.6% return on common equity. He relied upon the results of both a risk-premium method and a DCF analysis to derive his recommendation. His risk-premium study indicated a cost of common equity equal to 12.43%. The risk premium of 3.07% was calculated by taking the difference between the earnings/price ratios of CP&L and a group of companies comparable in risk to CP&L and the yields on U.S. Treasury bond yields from 1983-1986. He added the 3.07% risk premium to the yields currently on U.S. Treasury bond futures of 9.36% which equaled the 12.43% cost of common equity using this method. Dr. Bowyer's DCF analysis of CP&L and a group of comparable risk companies resulted in a 10.7% to 11.92% cost of common equity range. The dividend yield component of the DCF of 7.13% was the result of dividing a weighted average dividend by the weighted average market price over the 15-month period ended March 31, 1987. To determine the expected growth rate in dividends, Dr. Bowyer employed an average historical retention growth rate equal to 3.75%, an average of the Value Line dividend growth rate estimates equal to 3.57% and an average of Salomon Brothers five-year dividend growth rate forecast equal to 4.79%. Adding the 7.13% dividend yield to the 3.57% to 4.79% range in dividend growth rate estimates resulted in a cost of common equity equal to 10.7% to 11.92% for CP&L. Based on the results of these two studies, Dr. Bowyer recommended a return on common equity for CP&L of 11.6%.

As a check on the reasonableness of his return on equity recommendation, Dr. Bowyer compared the difference in the current level of interest rates and an 11.6% return on equity to the level of interest rates at the time CP&L was allowed a 15.25% return on equity by the Commission in Docket No. E-2, Sub 481. Dr. Bowyer testified that at September 30, 1983, the end of the test year in Docket No. E-2, Sub 481, yields on U.S. treasury bonds were 11.65%. The 15.25% return on CP&L's common equity allowed in that case was 363 basis points above the

11.65% level of interest rates. He cited that adding the 363 basis point difference to a current yield on U.S. treasury bonds of 8.02% produced a cost of common equity of 11.62%. In his opinion, this comparison confirmed the reasonableness of his 11.6% return on equity recommendation in this case.

Attorney General witness Smith relied upon a DCF analysis as the basis of her return on equity recommendation of 11.0%. Using market price data for the six-month period October 1986 through March 1987, and earnings, dividend, and book value data through year-end 1986, she estimated the cost of equity capital for CP&L to be 9.5% to 10.5%. The CP&L return estimate was the sum of CP&L's 6.9% dividend yield and a long-term dividend growth estimate for CP&L of 2.6% to 3.6%. She also estimated the cost of equity for the electric utility industry as a whole equal to 10.0% to 11.0% based upon a 7.0% dividend yield and a growth rate of 3.0% to 4.0%. However, Dr. Smith also testified that since her studies were completed, interest rates and dividend yields increased by 50 to 120 basis points. These circumstances indicated to her that the cost of equity to CP&L, and the industry as a whole, had increased since her DCF study was completed. Therefore, she recommended that the return on equity which CP&L should be allowed is 11.0%.

Dr. Smith's testimony also included a description of the historical earnings performance of electric utilities and industrial companies which showed that the earned returns of utilities has ranged from 13.0% to 15.0% over the last several years while the earned returns of unregulated companies has ranged from 10.4% to 13.2% in the last four years.

Dr. Smith rebutted the testimony of Dr. Vander Weide on four different points. First, she testified that the quarterly compounding adjustment made by Dr. Vander Weide is unnecessary. She pointed out that investors may earn reinvestment profits available to them from a source other than CP&L. She also stated that if CP&L paid only an annual dividend, CP&L could earn the reinvestment profits required by investors without ratepayers paying any additional charges. Second, she testified that CP&L will not incur flotation costs and even if it did, flotation costs would be substantially less than Dr. Vander Weide's allowance. Third, she disagreed with the use of the analysts' forecasts by Dr. Vander Weide, citing that five-year earnings growth projections of analysts are not the long-term dividend growth expectations of investors which are appropriate to employ in the DCF model. Fourth, Dr. Smith testified that Dr. Vander Weide's risk premium was based upon earned returns on stocks and longterm bonds and had no relation to equity and debt costs. It was also her opinion that if a risk premium approach was undertaken, the correct result would be a 10.5% cost of equity estimate employing data from the Ibbotson and Sinquefield study relied upon by Dr. Vander Weide.

Public Staff witness Sessoms recommended that the cost of common equity to CP&L is 11.79%. To determine his recommended return, Mr. Sessoms relied upon the results of a DCF study. His DCF study consisted of determining the proper dividend yields and growth rates for CP&L specifically and a group of companies which exhibited measures of investment risk similar to those exhibited by CP&L. The results of the DCF study for CP&L indicated an investor return requirement of 11.25% to 11.85%, based upon a dividend yield of 7.0% to 7.1% and an expected growth rate of 4.25% to 4.75%. The results of the DCF study of the comparable group indicated an investor return requirement of 11.35% to 12.20%, based upon an average dividend yield of 7.6% to 7.7% and an expected growth rate of 3.75% to 4.50%. From these ranges, he concluded the investor return requirement on CP&L's common equity is 11.75%.

Based on an examination of CP&L's known and actual financing costs attributable to the public issuances of common stock over the years 1977-1986, witness Sessoms calculated a factor of .04% which he testified would allow CP&L to recover the known and actual financing costs when added to the investor return requirement.

As a check on the reasonableness of his return recommendation, witness Sessoms stated that his recommendation would produce a pretax interest coverage calculation of approximately 3.2 times. His testimony also included a comparison which showed that if his return on equity recommendation of 11.79% were allowed by the Commission in this case, it would produce a higher spread over the current level of A-rated utility bond yields than did the Commission's decision in CP&L's last general rate case.

On cross-examination, witness Sessoms acknowledged that the use of a more current stock price in the dividend yield calculation would cause an increase in the dividend yield. However, he testified that his estimate of the required return for CP&L was appropriate under current conditions, because as Sessoms Late-Filed Exhibit No. 1 showed, he chose the upper end of the investor return requirement range for CP&L in recognition of lower stock prices at the end of his pricing period. Therefore, to increase the recommended return above 11.79% would effectively double count the effect of more recent stock prices which are lower. This exhibit also shows that if dividend yields were updated through June 8, 1987, the 11.75% investor return requirement which he recommended is in the very center of the range for CP&L as well as within the range of the comparable risk group. He was also asked several questions concerning the flotation costs incurred by CP&L and any market pressure incurred by CP&L. His testimony was that his .04% adjustment was proper and would allow CP&L to recover any known and actual financing costs. He testified that there was not even a theoretical basis for a market pressure adjustment, and even if market pressure was incurred, that was a shareholder risk reflected in the stock's price.

[23, 24] The determination of the appropriate fair rate of return for CP&L is of great importance and must be made with great care, because whatever return is allowed will have an immediate impact on CP&L, 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 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 fair to its customers and 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. G2-133(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 ...

North Carolina ex rel. Utilities Commission v. Duke Power Co., 285 N.C. 377, 6 PUR4th 390, 398 206 S.E.2d 269 (1974).

The nature of the evidence in a case such as this makes it extremely difficult to balance all of the opposing interests, since much, if not all, of the evidence is based on individual witnesses' perceptions and interpretations of trends and data from the capital market. The Commission must use its impartial judgment to ensure that all parties involved are treated fairly and equitably.

The rates of return on common equity recommended by the various parties in this case range from a low of 11.0% recommended by Dr. Smith to a high of 14% recommended by Dr. Vander Weide. It is generally agreed that the determination of a fair and reasonable rate of return is a matter of informed judgment and that the various methodologies used to make such a determination serve as no more than guides or channels to aid in exercising such judgment. In the final analysis, the judgment must be made by the Commission. In North Carolina ex rel. Utilities Commission v. General Teleph. Co. of the Southeast, 281 N.C. 318, 370, 371, 189 S.E.2d 705 (1972), the North Carolina Supreme Court said:

> The apparent precision with which experts, both for the utility and the protestants, compute a fair return is somewhat illusory. The habitual bickering and theorizing of such witnesses over the relative merits of methods of computing cost of equity capital, such as the earnings-toprice ratio or the discounted cash flow, lends a false appearance of certainty to the ultimate decision which is for the Commission.

See also North Carolina ex rel. Utilities Commission v. Duke Power Co., 305 N.C. 1, 23, 287 S.E.2d 786 (1982) ("the determination of what constitutes a fair rate of return requires the exercise of subjective judgment by the Commission ...").

Accordingly, the Commission finds that the reasonable rate of return for CP&L to be allowed in this case on its common equity is 12.63%. Combining this with the appropriate capital structure and the costs of debt and preferred stock heretofore determined yields an overall rate of return of 10.45% to be applied to the Company's original cost rate base. Such rates of return will enable CP&L by sound management to produce a fair rate of return for its stockholders, 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.

The authorized rate of return on common equity of 12.63% allowed CP&L in this case is consistent with competent, material, and substantial evidence offered in this proceeding. Such evidence clearly indicates that interest rates have declined by 400 to 500 basis points since the time of CP&L's last general rate increase hearing in mid-1984, when the Company was granted a rate of return on common equity of 15.25%. It also reflects the fact that the Company's market-to-book ratio has been above 1 for some time; that Harris Unit 1 is now in commercial operation; that CP&L has been allowed a normalized capital structure in this case consisting of 43.0% common equity which is 3% higher than the Company was allowed in its last general rate case; and that CP&L's construction and accrual earnings on construction will decrease dramatically. The Commission further concludes that CP&L's risk has also been significantly decreased since the Company's last general rate case as a result of the fuel true-up procedures implemented for the Company in September 1985 pursuant to G.S. 62-133.2. The allowed equity return of 12.63% includes an adjustment to allow for the known and actual flotation costs associated with the public issuance of common stock.

The Commission believes that the rate of return on common equity of 14.0% requested by the Company is excessive, while the rates of return on common equity recommended by the Public Staff, CUCA and the Attorney General are too conservative. Therefore, it is the judgment of the Commission, after weighing the conflicting testimony offered by the expert witnesses, that the reasonable and appropriate rate of return on common equity for CP&L is 12.63%. 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). North Carolina ex rel. Utilities Commission v. Duke Power Co., 305 N.C. 1, 287 S.E.2d 786 (1982). The Commission has followed these principles in good faith in exercising its expert 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 Commission cannot guarantee that CP&L 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 believes, and thus concludes, that the rates of return approved in this docket will afford the Company a reasonable opportunity to earn a reasonable return for its stockholders while providing adequate economical service to its ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 19

The Commission has previously discussed its findings of fact and conclusions regarding the fair rates of return on rate base and common equity which CP&L should be afforded an opportunity to earn.

The following charts 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 conclusions heretofore and herein made by the Commission.

[Table below may contain distortions.]

SCHEDULE I
CAROLINA POWER & LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-2, Sub 526
STATEMENT OF OPERATING INCOME
Twelve Months Ended March 31, 1986
(000's Omitted)

Item	Present Rates	Approved Increase	Approved Rates
Operating revenues	$1,325,856	$92,467	$1,418,323
Operating revenue deductions			
Fuel and purchased power	270,641	—	270,641
Other operation and maintenance expenses	474,451	—	474,451
Depreciation	150,036	—	150,036
Taxes other than income	76,085	2,977	79,062
Income taxes	103,436	39,018	142,454
Total	1,074,649	41,995	1,116,644
Operating income before adjustments	251,207	50,472	301,679
Interest on customer deposits	(552)	—	(552)
Net operating income	$ 250,655	$50,472	$301,127

[Table below may contain distortions.]

SCHEDULE II
CAROLINA POWER & LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-2, Sub 526
STATEMENT OF RATE BASE AND
RATE OF RETURN
Twelve Months Ended March 31, 1986
(000's Omitted)

Item	Amount
Investment in electric plant	
Electric plant in service	$3,923,646
Net nuclear fuel	123,424
Accumulated depreciation	(836,080)
Accumulated deferred income taxes	(433,213)
Net investment in electric plant	2,777,777
Allowance for working capital	
Materials and supplies	77,444
Other rate base additions and deductions	(5,476)
Investor funds advanced for operations	32,781
Total working capital allowance	104,749
Original cost rate base	$2,882,526

Rates of return

Present Rates 8.70%
Approved Rates 10.45%

[Table below may contain distortions.]

SCHEDULE III
CAROLINA POWER & LIGHT COMPANY
North Carolina Retail Operations
Docket No. E-2, Sub 526
STATEMENT OF CAPITALIZATION
AND RELATED COSTS
Twelve Months Ended March 31, 1986
(000's Omitted)

Item	Capitalization Ratio (%)	Original Cost Rate Base	Embedded Cost (%)	Net Operating Income
Present Rates—Original Cost Rate Base				
Long-term debt	48.50	$1,398,025	8.81	$123,166
Preferred stock	8.50	245,015	8.74	21,414
Common equity	43.00	1,239,486	8.56	106,075
Total	100.00	$2,882,526		$250,655
Approved Rates—Original Cost Rate Base				
Long-term debt	48.50	$1,398,025	8.81	$123,166
Preferred stock	8.50	245,015	8.74	21,414
Common equity	43.00	1,239,486	12.63	156,547
Total	100.00	$2,882,526		$301,127

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20—24

The evidence regarding these findings of fact concerning rate design is found in the testimony and exhibits of Company witness Edge, Public Staff witness Turner, CIGFUR witness Phillips, and DOD witness Patwardhan.

Percentage Increases and Rates of Return

[25, 26] Company witness Edge testified that the Company's rate design objective is to move toward equalized rates of return for all customer classes, and that the Company seeks to design rates that result in a rate of return for each customer class that does not vary by more than 10% from the overall North Carolina retail rate of return. The Company proposed in this proceeding to increase rates for the residential and small general service customer classes by approximately 14.21%; increase rates for the large general service class by approximately 11.07%; increase rates for the sports field lighting class by approximately 13.07%; and maintain the lighting class (other than sports field lighting) at current rates.

Public Staff witness Turner offered several rate design alternatives which would also move the rate classes toward equalized rates of return. He recommended increasing the residential, small general service, and large general service customer classes by approximately 11.10%; increasing the sports field lighting class by approximately 11.92%; and maintaining at current rates or decreasing the lighting class (except sports field lighting) by certain amounts depending on the resulting rates of return.

CIGFUR witness Phillips recommended that each customer class be increased in such a way as to reduce the deviation between that class rate of return and the overall North Carolina retail rate of return by 50%.

DOD witness Patwardhan recommended that each customer class be increased in such a way as to equalize class rates of return over time, and that the increase for the large general service (LGS) class should be reduced to ensure that the rate of return of the LGS class does not deviate from the overall North Carolina retail rate of return by more than 10%.

The Commission notes that the increases proposed by either the Company or the Public Staff would result in class rates of return for the residential, small general service, and large general service classes which are within approximately 5% of the overall North Carolina retail rate of return based on the summer/winter peak and average cost allocation methodology. Furthermore, the increases proposed by either the Company or the Public Staff would result in class rates of return for the sports field lighting class which are still more than 20% below the overall North Carolina retail rate of return based on the summer/winter peak and average allocation method, and the current rates or the decreases proposed by the Public Staff for the lighting class (except sports field lighting) would result in class rates of return which are still more than 30% above the overall North Carolina retail rate of return.

[27] G.S. 62-140 prohibits rates which provide any "unreasonable preference or advantage of any person." The North Carolina Supreme Court has stated that the issue with respect to G.S. 62-140 "is not whether the differential is merely discriminatory or preferential; the question is whether the differential is an unreasonable or unjust discrimination." North Carolina ex rel. Utilities Commission v. Carolina Utilities Cus tomers Association, 314 N.C. 171, 195 (1985). The Commission believes the evidence in this case supports a movement toward equal rates of return. The Commission also recognizes that the cost studies available in this case relate only to a brief historical period. Customer demand and energy usage characteristics vary from time to time, and they must be evaluated over an extended period of time in order to determine normal variations in rates of return. Therefore it is unrealistic to expect to design rates which will produce exactly equal rates of return over time.

The Commission concludes that rates for the large general service class should be increased by 0.9 times the percentage increase applied to the residential and small general service classes herein; that rates for the sports field lighting class should be increased by 1.1 times the percentage increase applied to the residential and small general service classes herein; and that rates for the lighting classes (except sports field lighting) should be maintained at current levels.

The Commission recognizes that the information contained in the cost allocation studies in this proceeding will change somewhat as a result of the various adjustments to revenues, expenses, and rate base adopted herein. Nevertheless, the Commission is of the opinion that the figures contained in the cost allocation studies in evidence are a reasonable basis for concluding that the rate designs adopted herein will not result in unreasonable discrimination between the rate classes for purposes of this proceeding. The cost allocation studies indicate that the rate designs approved herein are not discriminatory and will result in substantial movement toward equalized class rates of return in this proceeding.

Large General Service Demand Charges

[28] The Company proposed to revise the demand charge in its large general service rate schedule from a single billing block to three billing blocks: 0-5,000 kW, 5,000 to 10,000 kW, and over 10,000 kW. The additional billing blocks are intended to recognize the different voltage levels at which large customers receive service. Company witness Edge explained that the smallest loads typically are served from the distribution system, the largest loads are typically served from the transmission system, and intermediate sized loads are typically served from either the transmission or distribution systems or substations in between. The Public Staff and CIGFUR II supported the Company's proposal.

DOD witness Patwardhan proposed that the large general service demand charge be revised from a single billing block to four billing blocks: transmission level, transmission/distribution substation, primary distribution level, and primary/secondary distribution substation. He contended that such blocking would more directly recognize the different voltage levels of service than would blocking based on size of load.

Witness Edge testified on cross-examination that demand charges based directly on voltage levels of service rather than on size of load might encourage customers to specify transmission level voltage requirements when applying for service even when their actual needs could be supplied by distribution level voltage.

The Commission is of the opinion that the demand charge blocks proposed by the Company should be adopted.

Demand Ratchets

[29] DOD witness Patwardhan testified that the demand ratchet currently incorporated in the general service rate schedules is counterproductive to the Company's load management objectives. The ratchet provides for a minimum monthly billing demand of at least 80 percent of the maximum summer demand or 60 percent of the maximum winter demand during the previous 12 months. The Company does not propose to change its demand ratchet.

The Commission has reviewed the demand ratchet in detail in previous dockets and concluded that time-of-use (TOU) rates should not include a billing demand ratchet although the Company's billing demand ratchet for non-TOU rates was acceptable. Such conclusion was based on testimony that demand ratchets are a poor second choice to TOU rates as a peak load pricing mechanism, and that TOU rates are available to all customers on a voluntary basis.

The Commission concludes that the demand ratchets proposed for non-TOU rate schedules should be accepted for purposes of this proceeding.

New Schedule SGS-TES

[30] The Company proposes a new Small General Service Thermal Energy Storage (SGS-TES) rate schedule which offers thermal energy storage service on a voluntary basis to nonresidential customers with less than 1000 kW contract demand. The rate schedule incorporates fewer on-peak hours than the small general service TOU rates in order to better permit feasible operation of thermal storage equipment during on-peak periods.

The Public Staff supports the proposal, but expressed concerns that the reduced on-peak hours might have a great enough impact on the system peak to cause a shift in the timing of the system peak. The Public Staff recommended that the loads served under the new rate schedule SGS-TES be monitored and recorded, and that the information from the monitoring devices be analyzed periodically in order to determine what impact such loads might be having on the system peak.

The Commission is of the opinion that the Public Staff recommendation has merit but desires to ensure that the expense of such a monitoring program is not out of proportion to the expected benefits of the SGS-TES rate schedule. Therefore, the Commission concludes that the Company should file a plan for monitoring the loads of new SGS-TES customers in such a way as to provide data in a cost-effective manner for making a valid analysis of the impact of such loads on the system.

Traffic Signal Service

Public Staff witness Turner testified that the Company is conducting a study to determine the kWh usage attributable to various traffic signal installations, and that thus far it has found a significant difference between the kWh usage assumed in the rate schedule and the kWh usage measured at specific installations. The preliminary findings raise questions about the validity of the charges for traffic signal service based on the usage assumed in the rate schedule. Continuing study will hopefully lead to an improvement in the estimates of kWh usage contained in the rate schedule or will indicate the necessity for metering each traffic signal installation.

The Public Staff recommended that the Company be required to prepare a detailed study of the kWh usage attributable to the various traffic signal configurations for presentation with its next general rate case.

The Commission is of the opinion that the Company should continue its investigation and that the Public Staff recommendation should be adopted.

Line Extension Plan E-1 and Rider 19

The Company's general rate application included a proposal to replace its various line extension plans with a single Line Extension Plan E-1 in order to treat both new underground and new overhead line extensions as standard. By separate Order issued June 25, 1987, in this docket, the Line Extension Plan E-1 was approved. However, underground service Rider 19 was not withdrawn by the Order of June 25, 1987, because of the corresponding revenue effect. The Commission now concludes that Rider 19 should be discontinued as it is no longer needed.

Service Regulation's—New Section 15

The Company proposes to add a new service regulation specifying that when the company incurs costs in preparing to furnish service to a person who has advised the company that he intends to contract with the company for electric service, and the person thereafter fails to contract with the company within a reasonable period of time, then such person shall be liable for the costs incurred by the company in preparing to serve him. The proposal was uncontested by any party.

However, the Commission is of the opinion that the proposed regulation would be more appropriate if it contained the language "subject to review by the Utilities Commission" at the end of the paragraph and concludes that such additional language should be adopted.

Miscellaneous

The following rate design changes were proposed by the Company and were uncontested by any party in this proceeding:

(A) Include the rate adjustments contained in the cost of fuel rider, the EMF rider, and the order correction rider in all basic rates instead of in separate riders in order to simplify customer bills.

(B) Increase the charges for three-phase service in the residential and small general service rate schedules from $5.25 to $6.25.

(C) Include 9 holidays in the off-peak hours for all TOU rate schedules.

(D) Retain the basic customer charge for residential non-TOU rates at $6.65.

(E) Discontinue the higher charge for the first 800 kWh during the winter months (thereby charging the same price per kWh for all kWh during the winter months) in residential non-TOU rates. The rates are already the same price per kWh during the summer months. The kWh differential between summer and nonsummer energy charges will be maintained at $0.01 per kWh.

(F) Delete the provisions in the residential rates governing multiple dwelling units. Master metering is no longer permitted so the provision is not needed.

(G) Eliminate the separate thermal requirements for manufactured housing in the residential rates. Both conventional housing and manufactured housing now must meet the same thermal requirements to qualify for a 5% conservation discount.

(H) Revise the name of residential schedule R-TOU to R-TOU-D in order to clarify its distinction from schedule R-TOU-E.

(I) Revise the applicability clause in residential schedule R-TOU-E in order to delete the 500 customers limitation and to delete the rate's "experimental" designation. Also revise the on-peak and off-peak hours for schedule R-TOU-E to match the other TOU schedules.

(J) Revise the contract period for residential TOU rates from one-year to onemonth for customers not previously on such rates. The contract period for customers returning to TOU rates will still be one-year.

(K) Reduce the current basic customer charge in residential T0U rates from $11.31 and $10.39 to $9.75 in recognition of the expected lower cost of metering such service.

(L) Delete residential schedules R-FEA-2 and R-FEA-3. They were experimental schedules, and no customers are served under them any longer.

(M) Increase the rates for closed rate schedules AHS, CSG, CSE, and RFS by approximately 10 percentage points more than the overall increase in order to merge the closed schedules closer to the active schedules. This is the same process followed in all of the Company's rate cases over the past 8 years.

(N) Reduce the demand charge for large general service customers owning their own step-down transformers in order to offset those Company owned transformation costs built into the demand charges for large general service.

(O) Add rates for 5 lamp traffic signal fixtures on schedule TSS.

(P) Delete requirement for a written contract when obtaining service under area lighting schedule ALS.

(Q) Delete the 6,000 lumen incandescent fixture from the street lighting schedule SLS.

(R) Add a provision to schedules ALS and SLS governing customer contributions for outdoor lighting service under the Line Extension Plan E-1.

(S) Revise Military Service Rider 28 to clarify that it is available to both LGS and LGS-TOU; and eliminate the requirement for a five-year contract under the Rider.

(T) Increase the maximum kW available to the total system for curtailable load under Curtailable Load Rider 58 from 100,000 kW to 150,000 kW; and add provisions governing two types of curtailable periods (economy and capacity) under the Rider. The two types of curtailable periods will give customers additional options for curtailing load.

(U) Revise street lighting service regulations to provide for a pro rata reduction of charges during periods when lighting fixtures are inoperable.

(V) Revise general service regulations to:

(1) increase service charges for new connections from $12.00 to $14.00; (2) increase service charges for reconnections from $12.00 to $14.00 during normal business hours and from $25.00 to $30.00 during nonbusiness hours; (3) increase returned check charges from $6.00 to $7.00; (4) increase the low power factor adjustment from $0.25 to $0.30 per kW; (5) include waiver of certain charges following a natural disaster; (6) clarify customer rights and responsibilities in selection of rate schedules and riders; and (7) clarify company right of access to a customer's property over the same general route as the customer uses.

Based on its review of the Company's proposals the Commission concludes that the rate designs, rate schedules, and service regulations proposed by the Company should be approved except as discussed herein.

IT IS, THEREFORE, ORDERED as follows:

1. That CP&L is hereby authorized to adjust its electric rates and charges so as to produce an increase in gross annual revenues from its North Carolina retail operations of $92.5 million, said increase to be effective for service rendered on and after August 5, 1987. However, due to the effect of the refund ordered in Decretal Paragraph No. 7 of this Order and the effect of a companion Order entered by the Commission on August 5, 1987, in Docket No. E-2, Sub 533, approving a fuel charge rate reduction for CP&L, the net revenue increase authorized for the coming year will be $5.4 million based upon the test year level of operations. The fuel charge rate reduction and the tax rate change refund will remain in effect for a period of one year beginning August 5, 1987, the date the Commission issued its Notice of Decision and Order and Order Approving Fuel Charge Adjustment in Docket No. E-2, Subs 526 and 533.

2. That the Commission's Notice of Decision and Order dated August 5, 1987, and the Order Approving Tariff Filing dated August 21, 1987, be and the same are hereby, reaffirmed.

3. That CP&L shall prepare cost allocation studies for presentation with its next general rate case which allocate production and distribution plant based on the following methods: (a) summer/winter peak and average including minimum system technique; (b) summer/winter peak and average excluding minimum system technique; (c) 12-month coincident peak including minimum system technique; and (d) 12-month coincident peak excluding minimum system technique. The studies shall be included in item 45 of Form E-1 of the minimum filing requirements for general rate applications.

4. That CP&L shall prepare a study supporting its depreciation rates for presentation with its next general rate case.

5. That CP&L shall prepare a detailed study of the differences in kWh usage attributable to the various traffic signal configurations for presentation with its next general rate case.

6. That CP&L shall file with the Commission within 90 days after August 5, 1987, a plan for monitoring the on-peak loads of customers served under new rate schedule SGS-TES in such a way as to provide data in a cost-effective manner of making a valid analysis of the impact of such loads on the system.

7. That effective January 1, 1988, the federal income tax and the related gross receipts tax

components of the rates and charges approved in this proceeding for CP&L shall be billed and collected on a provisional rate basis pending further investigation and final disposition of this matter concerning the impact of the Tax Reform Act of 1986 on the Company's cost of service. CP&L shall establish a "second deferred account" as of January 1, 1988 in which shall be accrued the difference between revenues billed under approved rates reflecting a 40% federal income tax rate and revenues that would have been billed if rates had been determined based upon a 34% federal income tax rate. Interest at a rate of 10% per annum shall be applied to this account and to the "first deferred account" established in Docket No. M-100, Sub 113, which tracked the difference in revenues billed under current rates reflecting a 46% federal income tax rate and revenues that would have been collected if rates had been based upon a 40% federal income tax rate. The "first deferred account" reflects an overcollection by CP&L of federal income tax expense of approximately $26 859,000 from its North Carolina retail customers for the period extending from January 1, 1987, through August 5, 1987. Such overcollection shall be refunded to the Company's customers during the 12-month period beginning August 5, 1987.

8. That CP&L shall file concurrent with the filing of its next general rate case application a calculation of the total overcollection of income tax expense which occurred during the period January 1, 1987, through August 5, 1987, arising from the change in the maximum corporate income tax rate from 46% to a blended rate of 40% for calendar year 1987. Ten copies of all workpapers developed in this regard shall also be filed with the Commission's Chief Clerk. Further, once refund of this income tax expense overcollection is complete, CP&L shall file with the Commission a final accounting of the total amount refunded in this regard including a statement setting forth any net over- or under-refund of said overcollections. The aforementioned final accounting shall be filed no later than September 30, 1988. This accounting and reporting requirement supersedes the accounting and reporting requirement relating to this matter as previously established by the Commission in its Order of August 5, 1987 issued in Docket No. E-2, Sub 526.

9. That within 10 working days after the date of this Order, CP&L 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 herein. Said computations shall be based on the cost allocation methodology adopted herein, including the treatment adopted herein for the minimum system technique, adjustment of allocation factors to reflect power agency buyback percentages, power agency reserve capacity, and normalization of power agency actual entitlement energy.