BEFORE THE
PUBLIC UTILITY COMMISSION OF FLORIDA

In RE: Petition for rate increase by Progress Energy Florida, Inc.	Docket No. 050078-EI

Direct Testimony and Exhibit of

Alan Chalfant

On behalf of

White Springs Agricultural Chemicals, Inc.
d/b/a PCS Phosphate – White Springs

July 13, 2005
Project 8383

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

BEFORE THE

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Direct Testimony of Alan Chalfant

Q **ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate – White Springs (White Springs). White Springs is a manufacturer of fertilizer products with plants and operations located within Progress Energy Florida Inc.'s (PEF) service territory at White Springs, and receives service under numerous rate schedules. During calendar year 2004, White Springs purchased approximately $20 million of power from PEF.

Q **WHAT IS THE SUBJECT OF YOUR TESTIMONY?**

A I will address portions of the Direct Testimony of PEF witness Dr. Charles Cicchetti. Specifically, I will address Dr. Cicchetti's proposal to add 50 basis points to PEF's allowed rate of return on equity as a reward for past performance. In doing so I will discuss the competing concepts of cost of service and performance-based ratemaking, as well as Dr. Cicchetti's statistical analysis of PEF's recent performance.

Q **PLEASE SUMMARIZE YOUR CONCLUSIONS.**

A My basic conclusion is that Dr. Cicchetti's proposal to "bump" PEF's allowed rate of return on equity by 50 basis points lacks credible support and should be rejected. That proposal violates the sound ratemaking principle that a regulated utility should be allowed the opportunity to recover only its costs which include a reasonable return on equity. Moreover, Dr. Cicchetti draws unwarranted conclusions regarding PEF's performance from his statistical analysis.

Q **AS A GENERAL MATTER, DO YOU BELIEVE THAT PEF'S PERFORMANCE WARRANTS A RETURN ON EQUITY BONUS?**

A Absolutely not. The Commission need look no further than a comparison of PEF's rates to those of other utilities in the Southeastern United States to see that PEF's claims of superior performance are hollow. As my associate, Mr. Brubaker demonstrates, PEF is one of the highest-cost suppliers in the region. Dr. Cicchetti's attempt to pick and choose performance metrics cannot change that fact. Neither can Dr. Cicchetti's secret (i.e., "proprietary") model that masks the fact that PEF is a high-cost supplier. As I discuss below, regulation serves as a surrogate for competition, and it is inconceivable that customers in a competitive market would reward a high cost supplier with an equity bonus. To the contrary, the competitive market would punish a high cost supplier – suggesting that if anything the Commission should impose an ROE penalty for PEF's poor performance relative to its peers.

Q PLEASE BRIEFLY DESCRIBE DR. CICCHETTI'S ARGUMENT FOR "BUMPING" PEF'S ALLOWED RATE OF RETURN.

A At page 51 of his direct testimony, Dr. Cicchetti recommends that the Commission add 50 basis points to the 12.3% ROE Dr. Vander Weide proposes on behalf of PEF "to reward PEF for its superior performance and encourage it to continue its efforts."

Q IS THIS A REASONABLE PROPOSAL?

A No. First, it is not reasonable to ask the Commission to "reward" PEF for its past performance. The "reward" for minimizing costs is the monopoly franchise granted to PEF and its predecessors. Second, there should be no need for the Commission to "encourage" PEF to minimize its costs in the future. Third, Dr. Cicchetti's statistical analysis falls short of demonstrating superior past performance.

Q WHY ISN'T IT REASONABLE FOR PEF TO ASK THE COMMISSION TO REWARD IT FOR PAST PERFORMANCE?

A PEF has done no more than the minimum that its customers and this Commission have a right to expect. As part of the implicit regulatory compact a utility is expected to provide reliable service at minimum cost in exchange for a monopoly franchise and the opportunity to recover its costs, including a reasonable profit, from Commission-approved rates. There is no reason that a utility should need to be bribed to keep its part of the bargain. This is particularly true here, where the performance that Dr. Cicchetti seeks to reward has resulted in some of the highest rates in the region – that certainly is not deserving of an ROE bonus.

Q WHY SHOULD THE COMMISSION ATTEMPT TO EMULATE COMPETITION IN ESTABLISHING THE RATES UTILITIES ARE ALLOWED TO CHARGE?

A Regulation has been relied upon as a surrogate for competition where the alternative would be a natural monopoly. Natural monopolies arise where one producer can achieve lower costs than two or more producers in the same market. Probably the best example of such economies of scale is the electric utility industry.

The regulatory compact or bargain represents a solution that avoids charging customers for monopoly profits while, at the same time, realizing the lower costs that result from a monopolist supplying the market. The benefit to the supplier is that, because it is granted a monopoly franchise, its risk of not earning a reasonable profit is reduced. Customers benefit because they are assured of adequate supplies of the product at the lowest cost.

The Commission, of course, plays a critical role in enforcing this regulatory compact. Absent Commission vigilance, a regulated utility such as PEF could extract monopoly rents from its customers by charging higher rates than a competitive market would permit. That is precisely what PEF is trying to accomplish through, among other things, its proposal to "bump" an already excessive return on equity by an additional 50 basis points.

Q BUT DOESN'T COMPETITION ALSO PROVIDE ADDITIONAL REWARDS FOR ENTITIES THAT ARE ABLE TO LOWER THEIR COSTS MORE THAN OTHERS?

A Yes, for very short periods, not unlike the situation encountered by a utility that reduces its costs or increases efficiency between rate cases. But there are several factors to consider. First, an entity in the competitive market may have the opportunity to increase its profits if it is more efficient than its competitors, but it is also at risk that its profits will be lower – or that it will incur a loss – if it doesn't perform well. Significantly, customers in the competitive market do not care about isolated performance metrics and secret models – they turn to the lowest cost supplier, and punish suppliers that are either high cost or low quality. Moreover, competition also includes the very forces which ensure that such extra rewards are short-lived. Improvements in operating efficiencies by one firm will soon be matched by its competitors or those competitors will quickly disappear to be replaced by more efficient new firms. Thus, competition does provide incentives and rewards for efficiency and innovation but they are one-time and not perpetual pensions.

Q DR. CICCHETTI STATES AT PAGE 9 OF HIS DIRECT TESTIMONY THAT "THESE PAST EFFORTS TO IMPROVE EFFICIENCY AND PRODUCTIVITY SHOULD NOT BE USED, AS SOME WOULD LIKELY PROPOSE, IN A MANNER THAT TAKES AWAY THE INCENTIVE OF UTILITY SUCCESS AND PASSES IT ON TO RATE PAYERS." DO YOU AGREE WITH THAT STATEMENT?

A No. Underlying Dr. Cicchetti's testimony is a disturbing concept that PEF is entitled to all of the profits that it can achieve. I believe that Dr. Cicchetti has it exactly backwards: regulation exists to protect <u>customers</u> from the power of the monopoly utility supplier, not to ensure that the monopoly utility can extract the maximum profit from its customers. Moreover, there are at least three additional problems with Dr. Cicchetti's statement. First, returning to a cost based revenue requirement does not "take away" the benefits that PEF has <u>already received</u> for any efficiencies. Second, the ability to retain additional profits between rate cases provides a strong incentive for PEF to find additional efficiencies. Third, as in a competitive market, ratepayers should, indeed, be the ultimate beneficiaries of any savings.

Q WHAT BENEFITS HAS PEF RECEIVED FOR ITS EFFICIENCIES?

A As Dr. Cicchetti points out at page 9 of his direct testimony, PEF made certain promises and set certain goals in connection with its proposed merger. At least in part based on these promises the Commission approved that merger. That in itself should be sufficient benefit for the Company. It was a bargain: If the Commission approved the merger, the Company would meet certain goals. The Commission did approve the merger and the Company claims it has met its goals. That completes the bargain. No more should be required. For the Company to now say it wants more in the form of perpetual rewards for keeping its side of the bargain is disingenuous.

But PEF has, in fact, received additional monetary benefits in recent years. Dr. Cicchetti notes at page 46 of his direct testimony that "Adjusting for storm damage and other developments, PEF has been earning about 13.3% on equity on a corrected basis." Ignoring Dr. Cicchetti's corrections, the Company is presently earning approximately 14.9% on equity. My associate, Mr. Gorman, has calculated that a change in the return on equity of 1% has a revenue impact of $44 million. Thus, comparing the present earnings to the amount Dr. Vander Weide has determined is reasonable -- 12.3% -- suggests that PEF is currently receiving a reward of more than $114 million per year of revenue in excess of costs. Comparing the present earnings to the more reasonable return on equity recommended by Mr. Gorman -- 9.8% -- indicates that the present excess revenues are approximately $225 million per year. The inescapable conclusion is that PEF has been rewarded handsomely for a number of years.

Q IF THE COMMISSION WERE TO RESET PEF'S REVENUES TO COST AT THIS TIME WILL THAT REMOVE THE INCENTIVE TO LOWER COSTS IN THE FUTURE?

A Certainly not. The rewards that PEF has earned in recent years will not soon be forgotten. PEF knows that by realizing cost savings in the future it can again earn substantial rewards. Any savings it achieves relative to the level of costs established in this case will be realized as excess earnings until rates are reset in a future rate case. As long as this regulatory lag is kept to a minimum and the Commission requires new rate proceedings whenever earnings exceed the allowed level, this properly emulates the working of a competitive market where firms are rewarded for cost savings for a short period while their competitors adjust their costs. Competition does not allow perpetual rewards and neither should regulation.

Q WHY DO YOU DISAGREE WITH DR. CICCHETTI'S STATEMENT THAT THE BENEFITS SHOULD NOT BE PASSED ON TO RATEPAYERS?

A The great benefit of competition is that it forces costs to their lowest levels to the benefit of consumers who pay only the costs (including reasonable profits) of production. In a regulatory framework where the attempt is to emulate competition the results should be the same. Except for very short periods, the customers should be the beneficiaries of lower costs and utilities are obligated by the regulatory compact to provide reliable service at the lowest possible cost.

Q AT PAGE 44 OF HIS TESTIMONY, DR. CICCHETTI TOUTS THE USE OF PERFORMANCE-BASED RATEMAKING. ARE YOU FAMILIAR WITH THAT CONCEPT?

A Yes.

Q IS THERE ANYTHING MISSING FROM DR. CICCHETTI'S PROPOSED APPLICATION OF THAT CONCEPT IN THIS CASE?

A Yes. Any even-handed application of performance-based ratemaking includes specific criteria for any adjustments above or below cost, and those criteria provide for symmetrical adjustments similar to competition. In other words, a utility that does something 10% better than the stated norm will be rewarded by the same amount as a firm that falls 10% short of the norm will be penalized. Dr. Cicchetti's proposal contains neither stated criteria nor a set of symmetric rewards/penalties. Rather, he simply judges that PEF should be allowed to earn a rate of return that is 50 basis points above the cost of equity.

Q DR. CICCHETTI REFERS TO AN ADJUSTMENT HE MADE TO THE RATES OF WISCONSIN ELECTRIC POWER COMPANY (WEPCO) IN 1979. HAVE YOU REVIEWED THE ORDER IN THAT CASE WHICH HE CITES IN FOOTNOTES 1 AND 9 IN HIS DIRECT TESTIMONY?

A Yes.

Q WAS THE ACTION TAKEN BY THE PUBLIC SERVICE COMMISSION OF WISCONSIN (PSCW) IN THAT CASE SIMILAR TO WHAT DR. CICCHETTI IS PROPOSING HERE?

A No. In that case WEPCO had requested a rate of return on equity of 14.5%. The three Commissioners adopted a return of 13.25%.

Q THEN ON WHAT BASIS CAN DR. CICCHETTI SAY AT PAGE 47 THAT HE ADDED 25 BASIS POINTS TO WEPCO'S RETURN ON EQUITY?

A The 25 basis point addition is to the 13.0% return that had been granted to utilities for some time prior to the WEPCO decision, as Dr. Cicchetti correctly explains. However, this is far different than a 50 basis point addition to the rate of return proposed by the Company's rate of return witness.

Q DR. CICCHETTI ALSO STATES AT PAGE 47 OF HIS DIRECT TESTIMONY THAT HE "REWARDED WISCONSIN ELECTRIC POWER COMPANY'S SUPERIOR PERFORMANCE (WHICH INCLUDED EMBRACING TARIFF REFORMS THAT BENEFITED CONSUMERS, COOPERATION WITH THE COMMISSION AND ITS STAFF, REDUCTION AND ELIMINATION OF

UNNECESSARY COSTS, AND A WELL MANAGED AND HEALTHY UTILITY)." WOULD YOU LIKE TO COMMENT ON THAT STATEMENT?

A Yes. In fact, most of Dr. Cicchetti's "reward" to WEPCO was based on rate design and had nothing to do with "superior performance" or "reduction and elimination of unnecessary costs." Prior to becoming a Commissioner, Dr. Cicchetti had been a vocal proponent of marginal cost pricing before the PSCW and elsewhere. WEPCO at the time was also a proponent of marginal cost pricing. In fact, in Dr. Cicchetti's Concurring Opinion he sets out what he refers to as "the criteria that I believe to be important for determining the rate of return on common stock equity." He then sets forth three criteria at page 13-14. Under his first criteria he states:

> (1) A utility that carries a small percent of equity relative to its debt and preferred stock is holding down the before (and after) taxes cost of capital for its ratepayers. These firms should expect a higher than average rate of return. . . ."

His second criteria states in part:

> (2) . . . Utilities who, for whatever reason, contribute to a delay in the adoption of marginal cost based tariffs, should accept the fact that their preference for a more certain gross revenue target at the expense of more secure earnings for their stockholders and better choices based upon proper price signals for their customers, will mean that I will vote for lower rates of return because such utilities are less risk oriented and inert. . . ."

His third criteria also deals with rate design.

> (3) . . . Rate design delays caused by a utility company should therefore not be rewarded either with these specific forms of adjustment or with rates of return in the upper part of the 12 to 13½ percent range. . . .

The entire WEPCO Order and Dr. Cicchetti's Concurring Opinion are attached, hereto, as Exhibit AC-1.

Q DR. CICCHETTI'S FIRST CRITERIA YOU NOTED ABOVE DEALT WITH THE UTILITY'S DEBT EQUITY RATIO. WHAT WAS THE PERCENT OF EQUITY APPROVED IN THAT ORDER?

A 40%.

Q WHAT BASIS IS GIVEN IN THE ORDER ITSELF IN SUPPORT OF THE 13.25% RATE OF RETURN?

A The Order states at page 4:

> "In recognition of the increased proportion of revenue that is subject to consumer and market uncertainty as a result of the adoption of marginal cost and time of use rate structure and of the crucial need to maintain applicant's financial integrity during a period of capital expansion, the commission considers a return on common stock equity of 13.25% to be reasonable and just for purposes of this proceeding."

Thus, I found no support in the PSCW Order or Dr. Cicchetti's concurring opinion that suggests that WEPCO was being rewarded for "superior performance."

Q ARE THERE ANY OTHER DIFFERENCES BETWEEN WHAT THE PSCW DID IN THE WEPCO CASE AND WHAT DR. CICCHETTI IS PROPOSING HERE?

A Yes. The 13.25% return on equity in the WEPCO case represented the mid-point of the range of reasonableness of 13.00 to 13.50 proposed by the PSCW Staff in that case and, as noted above, well below WEPCO's requested return. Dr. Cicchetti's proposal here would result in a rate of return on equity over and above the proposal of the Company witness.

Q HAVE YOU REVIEWED DR. CICCHETTI'S STATISTICAL ANALYSIS OF PEF'S PERFORMANCE?

A Yes.

Q DO DR. CICCHETTI'S CONCLUSIONS CLEARLY FOLLOW FROM THE ANALYSIS?

A No. I was unable to trace the output of Dr. Cicchetti's statistical model, which was supplied in response to White Springs' Second Set of Requests for Production of Documents, No. 28, to the Tables in his testimony but I have no reason to expect that they are not numerically accurate. What is troublesome about Dr. Cicchetti's testimony is his characterization of the results.

In particular, Dr. Cicchetti refers frequently to the "minimum achievable cost" (e.g. page 21, line 6) and the costs of an "efficient firm within the industry." He states the conclusion at page 22, lines 2-3, that "PEF's actual costs for the period studied were 12.7% below the costs the model predicted for PEF for a three-year composite period."

While that statement seems to imply that PEF has somehow managed to achieve costs lower than the minimum we must dismiss that result as absurd. What it does mean, in fact, is simply that after eliminating the effect of numerous factors that contribute to costs, the costs achieved by PEF were 12.7% less than a "typical firm in the industry." (See, e.g., PEF's Response to White Springs' Second Set of Interrogatories, No. 33a). Of course, whether this is good or bad is highly dependent on the factors that are selected for inclusion in his model.

Q IF PEF WERE TRULY A LOW COST SUPPLIER SHOULD THAT BE REFLECTED IN ITS RATES?

A Yes. One would expect that a low cost supplier would have lower rates than other utilities in the region.

Q DO PEF'S RATES AS COMPARED TO OTHER UTILITIES IN THE SOUTHEAST SUGGEST IT IS A LOW COST SUPPLIER?

A No. As Mr. Brubaker demonstrates in his testimony, PEF is one of the highest cost suppliers in the Southeastern United States. Indeed, its firm industrial rates are 2nd highest in the group. (See Exhibits MEB-1, MEB-2 and MEB-3). This casts serious doubt on the relevance of Dr. Cicchetti's model.

Q DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of Alan Chalfant

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Alan Chalfant. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

Q **WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and am a principal with the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I hold a Bachelor's Degree in Mathematics from Northern Illinois University and the degree of Master of Arts in Economics from Washington University. From 1968 to 1973, I was Assistant Professor of Economics at California State University at Northridge, California. Among other courses in economics and statistics, I taught courses in the economics of antitrust and regulation at both the graduate and undergraduate levels. I have also taught courses at both graduate and undergraduate levels at California Lutheran College.

In 1973, I accepted a position with the Public Service Commission of Wisconsin in the Utility Rates Division. While at the Commission, I designed the rates for electric and natural gas utilities and aided in the preparation for cross-examination of witnesses representing utilities and intervenors before the Commission.

I joined the firm of Drazen-Brubaker & Associates, Inc. in September 1974 and became a Principal in that firm in 1988. In April 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff and currently has its principal office in St. Louis, Missouri, with branch offices in Phoenix, Arizona; Chicago, Illinois; Corpus Christi, Texas; and Plano, Texas.

Since 1974, I have been engaged in the preparation of studies relating to utility rate matters and have participated in numerous electric and gas rate cases. In total, I have participated in cases involving more than 60 electric utilities, 30 gas distribution utilities and 20 interstate pipelines.

Q HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY COMMISSION OR A PUBLIC AUTHORITY?

A I have testified before the Federal Energy Regulatory Commission and more than 30 state public utility regulatory commissions. In addition, I have appeared before a number of municipal regulatory bodies and courts.

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Application of Wisconsin Electric Power Company forAuthority to Increase Its Flectric Rates
6630-ER-8

PUBLIC SERVICE COMMISSION OF WISCONSIN

1979 Wisc. PUC LEXIS 45

March 6, 1979

CORE TERMS: customer, tariff, electric, energy, measured, time-of-day, on-peak, residential, billing, maximum, billed, power factor, off-peak, load, rate of return, rate base, effective, monthly, common stock, meter, net investment, retail sales, retail, fuel, energy charge, consumption, allowance, recovered, marginal, interruptible

PANEL: [*1]

THE COMMISSION

OPINION: FINDINGS OF FACT AND ORDER

On April 21, 1978, Wisconsin Electric Power Company (hereinafter sometimes referred to as "applicant" or WEPCO") filed an application with the commission under ss. 196.03, 196.20 and 196.37, Wis. Stats., for authority to increase its electric service rates. The amount of the requested increase in revenues was not set forth in the application but the record, as subsequently developed, established the requested revenue increase to be $16,992,000, based on a 1978 test year.

Pursuant to due notice, hearings were held at Milwaukee on June 5, July 5, and July 7, 1978 before Examiner Clarence B. Sorensen. At such hearing, applicant requested that interim rate relief be granted based on the evidence in the record. The commission declined to grant interim rate relief and directed that further hearings be held to determine final rates based on a 1979 test year.

Pursuant to due notice, hearings were reconvened at Milwaukee on November 1, 2, and 13, 1978 and at Madison on November 8, 1978 before Examiner Sorensen and on December 19, 1978 before Examiner Wolter. The record, as developed, established the revised revenue increase requested based [*2] on test year 1979 to be $63,565,000.

At such hearings, applicant, staff, and intervenors presented and cross-examined testimony and exhibits concerning cost of service, rate design, revenue requirement and the cost of capital.

The request for rate relief is granted in the amount of $50,661,000, an overall retail revenue increase of approximately 9% or, on an annual basis since the last adjustment of base rates authorized by the commission order in docket 6630-ER-5 dated January 5, 1978, 7.7%.

Appearances are listed in appendix A

Findings of Fact

THE COMMISSION FINDS:

Applicant and Its Business

Wisconsin Electric Power Company is an electric public utility as defined in s. 196.01, Wis. Stats., engaged in the production, transmission, distribution, and sale of electric energy to approximately 720,000 retail customers in eastern Wisconsin. The territory served includes the city of Milwaukee and its surrounding area, the cities of Racine, Kenosha, Waukesha, Fort Atkinson, Watertown, West Bend, Whitewater, Appleton, Neenah, and various area of eastern and northern Wisconsin and parts of upper Michigan. Applicant also sells energy at wholesale to municipal utilities operating[*3] in Cedarburg, Deerfield, Elkhorn, Hartford, Jefferson, Kiel, Lake Mills, Oconomowoc, Slinger, and Waterloo. The rates applicable to sales of electric energy at wholesale to municipal utilities for resale, being in interstate commerce, are not subject to the jurisdiction of this commission but are regulated by the Federal Energy Regulatory Commission and hence not affected by these proceedings. Applicant also operates as a steam-heating utility in certain areas of Milwaukee.

A wholly owned subsidiary, Wisconsin Natural Gas Company, operates as a natural gas distribution utility in various areas in northeastern and southeastern Wisconsin. Applicant and the former Wisconsin Michigan Power Company, a wholly-owned subsidiary, were merged effective December 31, 1977.

Income Statement

Applicant and staff presented testimony and exhibits concerning the estimate of 1979 electric utility operations and opportunity was afforded all parties to cross examine such testimony. Applicant challenged staff-proposed elimination of advertising expenses from the cost of service and provided additional testimony and exhibits justifying advertising expenditures in the amount of $920,000 applicable[*4] to electric operations under the jurisdiction of this commission. The commission has determined a just and reasonable allowance for applicants advertising activities to be $370,000 and accepts staff's income statement in all other respects. This advertising allowance will permit applicant to continue to advertise safety and conservation and to engage in advertising required by law, such as the publishing of financial statements and notification of consumers of their electric tariffs. Advertising designed to promote the corporate image is not a just and reasonable expense to include in the cost of service; the actions taken herein exclude cost of image-building advertising from the advertisint allowance.

Intervenors challenged the reasonableness of the commission's order in docket no. 6630-DU-1, dated August 29, 1978, which provided, among other things, an increase in annual depreciation expense of approximately $2,000,000 to provide for the removal cost associated with Applicant's Point Beach Nuclear Generating Station. The depreciation rates certified by the commission in accordance with s. 196.09, Wis. Stats., are designed to recover, over the service life of an asset, the [*5] original book cost minus the net salvage value of the asset. The Uniform System of Accounts adopted by the commission in docket no. 2-U-7623, dated June 18, 1973, defines net salvage value as "the salvage value of property retired less the cost of removal." For many years the Commission has recognized that various classes of utility plant have cost of removal in excess of salvage value at the time of retirement, and such cost of removal was reflected in the certified depreciation rates. Decommissioning of a nuclear generating facility may be an example of such a cost. The depreciation rates certified in docket no. 6630-DU-1 recognize that fact by appropriately adjusting the cost of removal estimates which underlie the certified depreciation rate. The certified depreciation rates are designed to recover through charges to depreciation expenses the cost of all utility plant less salvage and plus cost of removal over the service life of the utility plant. In this way, the proper cost is recovered from customers while the utility plant is actually in service.

The Nuclear Regulatory Commission recently initiated a complete re-evaluation of its policy on decommissioning nuclear facilities. [*6] That re-evaluation will include possibly pre-emptive Federal rules for accumulation of an allowance for required decommissioning. Present Public Service Commission policy provides for decommissioning costs and is sufficiently flexible to allow incorporation of subsequent adjustments of that policy or requirements of Federal law. The commission believes that no valid purpose would be served by changing the method of determining just and reasonable depreciation rates at this time.

The claim that the method of computing depreciation rates employed by the commission results in higher cost to consumers is unfounded. By accounting for the cost of removal as depreciation expense, over the asset's service life, the commission reduces the net investment rate base, which results in lower ad valorem taxes and insurance costs, in addition to the reduced revenue requirement resulting from a reduced rate base. For every dollar the consumer supplies for cost of removal, he or she will receive an approximate 11% return, in the form of reduced revenue requirement over the life of the asset, under current Federal and state tax laws. Should the tax laws be changed to provide a current tax deduction[*7] for the annual provisions for cost of removal, the consumers will receive an approximate 19% return on dollars supplied for cost of removal. The commission has taken steps to effect such changes in the tax laws: critics of our method of depreciation would gain the most by joining our efforts at changing the tax laws.

Accordingly, the income statement reflecting estimated results of 1979 electric operations under jurisdictions of this commission, for purposes of establishing tariffs for electric service, adjusted from staff estimate for advertising expense and the effect on income taxes of a change in the short term interest rates, is as follows:

1979 Test Year
Retail Electric Income Statement

Operating Revenues	(000's)
Sales of Electricity	$556,533
Other Electric Revenues	7,182
Total Operating Revenues	$563,715
Operating Expenses	
Power Production Expenses	$261,274
Transmission Expenses	4,709
Distribution Expenses	38,625
Customer Accounts Expense	12,742
Customer Services and Informational Expenses	976
Sales Expense	889
Administrative and General Expenses	44,419
Total Operation and Maintenance Expenses	$363,634
Depreciation Expense	64,632
Amortization Expense	545
Taxes Other Than Income Taxes	33,670
State Income Taxes	1,207
Investment Tax Credits - Deferred	19,550
Investment Tax Credits - Restored	(1,948)
Total Operating Expenses	$481,290
Net Operating Income	$ 82,425

[*8]

Net Investment Rate Base

The estimated average net investment rate base for the test year 1979 for applicant's retail electric operations, found reasonable and just for purposes of determining revenue requirement in this proceeding, is as follows:

Net Investment Rate Base	(000's)
Plant in Service	$1,468,696
Less: Accumulated Depreciation	586,073
Net Plant In Service	$ 882,623
Materials and Supplies	103,113
Less: Contributions in Aid of Construction	14,255
Net Investment Rate Base	$ 971,481

Earned Rate of Return

Estimated operating income of $82,425,000, when applied to the average net investment rate base of $971,481,000, results in an earned rate of return of 8.48%.

Cost of Capital

Applicant's estimated corporate capital structure as of December 31, 1979 will consist of approximately 40.0% common stock equity, 10.0% preferred stock, 46.0% long-term stock debt, and 4.0% notes payable.

Applicant's outstanding issues of common, preferred stock and debentures are, in part, applicable to its investment in its wholly-owned subsidiary, Wisconsin Natural Gas Company. The commission, in past proceedings involving rates for the utility companies in the Wisconsin[*9] Electric Power Company system, has properly allocated capital on a consolidated basis so as to follow the commission's procedure for all holding-company systems wherein a determination is made as to the source of equity capital in subsidiaries. This procedure has again been followed.

Applicant, in this proceeding, has requested that a 14.5% return on applicable comon stock equity be authorized. Applicant's witness testified that this is the minimum return required in order to maintain its financial integrity. Applicant's witness cited the capital expansion necessary over the next several years, required by current construction of utility plant, as a critical issue at a time when the money markets are closely scrutinizing potential issues of capital.

Commission staff witness presented a comprehensive study on cost of capital and concluded that a reasonable and just rate of return on applicant's common stock equity would be 13.5%. Staff witness cited an increase in perceived risk by investors in public utilities as the primary reason for increasing the return on common stock equity from 13% to 13.5%.

The commission finds that returns on common stock equity should be authorized [*10] on a company-by-company basis. An increase in the authorized return on common stock equity for one company does not establish a new plateau of returns on common stock equity for all other utilities, regardless of the particular financial situation of each company.

For the test year 1979, applicant will have a capital structure consisting of approximately 40% common stock equity, 10% preferred stock equity and 50% debt. In consideration of applicant's construction activities during the next 3 years, this capital structure is reasonable and just for purposes of establishing rates for electric utility service. The commission has ordered, in recent rate orders, significant rate reform for applicant, including seasonal rate differentials, time-of-day rates for industrial customers and an interruptible rate for industrial customers. In recognition of the increased proportion of revenue that is subject to consumer and market uncertainty as a result of the adoption of marginal cost and time of use rate structure and of the crucial need to maintain applicant's financial integrity during a period of capital expansion, the commission considers a return on common stock equity of 13.25% to [*11] be reasonable and just for purposes of this proceeding.

In view of increasing the allowed return on common stock equity from 13.00% to 13.25%, the commission reaffirms its present position that attrition allowances, make-whole increases and interim increases should not be considered as the ordinary course of events for utilities requesting rate relief. This is not to say that these regulatory tools are being discarded, but the test to determine their application is now more stringent. The commission will examine the facts and circumstances on a case-by-case basis and, if appropriate, will implement interim rate orders, make-whole increases and attrition allowances.

Accordingly, capitalization ratios, annual cost rates and a composite cost of capital rate applicable to the retail electric operations of applicant, which are reasonable and just for purposes of this proceeding, are as follows:

	Capitalization Ratios	Annual Cost Rate	Weighted Cost
Common Stock Equity	40.0%	13.25%	5.30%
Preferred Stock	10.0	7.97	.80
Debt:			
Long-Term			
Bonds	43.5	7.12	3.10
Debentures	2.5	7.00	.18
Short-Term	4.0	11.75	.47
Composite Cost of Capital Rate	100.00%		9.85%

[*12]

Rate of Return

Once the composite cost of capital rate has been determined, it is necessary that this rate be translated into a rate of return to be applied to net investment rate base to establish an overall return requirement in dollars.

Here, the average net investment rate base, plus construction work in progress, is 103.12% of capital applicable primarily to utility operations. This figure is reasonable and just in translating the composite cost of capital into a return requirement applicable to net investment rate base.

Applicant presently employs a 7% allowance for funds used during construction to that portion of construction work in progress which exceeds 10% of net investment rate base. Intervenors in this proceeding have closely questioned the procedure currently authorized by the commission. The commission, in this proceeding, reffirms the presently employed method as the least costly method over the long run. Recovering the full capital costs of construction work in progress in the form of recorded allowance for funds used during construction will decrease the current revenue requirement, however, the future revenue requirement over the life of the property[*13] will increase by approximately four times. Intervenors claim this to be the proper method because utility plant under construction does not benefit present rate payers. This claim is seriously flawed. First, a significant amount of construction work in progress is devoted to expanding and strengthening the transmission and distribution systems which does provide benefits to exsisting consumers in the form of increased reliability of electrical service. Second, construction of power plants and major transmission facilities which will not provide service for several years still provides a benefit to present rate payers in that they are assured of an adequate supply of energy in the future. In recognition of the benefit of construction work in progress to present rate payers, the commission finds it reasonable and just to recover from current consumers the current capital costs on that portion of construction work in progress up to 10 percent of net investment rate base.

Although the procedure authorized herein is found reasonable and just for purposes of this proceeding, the commission has directed that a generic proceeding concerning the treatment of allowance for funds used [*14] during construction be undertaken to fully evaluate all reasonable methods.

Accordingly, the rate of return on net investment rate base reasonable and just for the purposes of establishing revenue requirement in this proceeding, computed on the basis of the above findings, with an allowance of .05% for miscellaneous corporate expenses, is as follows:

		Electric Utility
Composite Cost of Capital		9.85%
Average Percent of Utility net Investment Rate Base to Capital Applicable Primarily to Utility Operations		103.12%
Adjustment to cost of capital rate to derive percent return requirement		
applicable to net investment rate base (9.85% + 103.12%)		9.55%
Allowance for Miscellaneous Corporate Expenses		.05%
Adjustment to Overall Return Requirement on Net Investment Rate Base from Effect of Cost of Capital on Construction Work in Progress		
Electric Construction Work in Progress as Percent of Net Investment Rate Base	31.24%	
Electric Construction Work in Progress Bearing Interest During Construction Rate of 7.00% as Percent of Net Investment Rate Base	21.24%	
Adjustment to Return Requirement to Provide Return on Construction Work in Progress (31.24% X 9.55%) - (21.24% X 7.00%)		1.49%
Adjusted Percent Return Requirement		

on Net Investment Rate Base	11.09%

[*15]

Revenue Requirement

On the basis of the above findings, the increase in electric utility revenue for retail electric service under the jurisdiction of this commission considered reasonable and just for purposes of determining tariffs for electrical service in this proceeding is $50,661,000, computed as follows:

	Retail Electric Utility
Return Earned on Net Investment Rate Base at Present Rates	8.48%
Percent Rate of Return Requirement of Net Investment Rate Base	11.08%
Deficiency in Earnings as of a Percent of. Net Investment Rate Base	2.61%
Average Net Investment Rate Base	$971,481,000
Amount of Earnings Deficiency	$ 25,356,000
Amount of Revenue Deficiency to Provide for Earnings Deficiency Plus Increased Federal and State Income Taxes	$ 50,661,000
Total Wisconsin Retail Electric Revenue Requirement	$614,376,000

Source and Amount of Rate Increases, 1977-1979

The most recent change in electric base rates for Wisconsin Electric Power Company was by order of the commission on January 5, 1978 in docket 6630-ER-2/5, in which rates were increased by $11,244,000 annually, based on test year 1977. The commission's order in this proceeding is to reflect[*16] in rates for electric service the change in operation and maintenance expenses, depreciation, taxes and return on investment from the test year 1977 through 1979. The rate increases authorized herein represent a net increase in rates of approximately 9% for the electric utility operations under jurisdiction of this commission. For the most recent two-year period, the cost of living in the Milwaukee area, which is a significant component of applicant's service area, has increased by 14.61%. The overall increase in electric revenues in this proceeding of 9% is less than the increase in the cost of living of 14.61%.

Wisconsin public utilities are encouraged to follow operating practices and procedures to operate insofar as possible in an efficient manner which in times of continuing inflation will result in changes in rates for public utility service at levels less than increases in the consumer price index.

Compliance with Wage and Price Standards

The rate increase authorized herein is in compliance with the revised wage and price standards issued on December 13, 1978 by the Council on Wage and Price Stability. This commission is required by statute to set rates for utility [*17]service to recover the cost to provide that service, however, the commission also recognizes its responsibility to comply, where possible, to the voluntary standards in an attempt to control inflation, one of the main causes of rapidly rising utility rates.

Since electric, steam and gas utilities purchase substantial amounts of commodities which are exempt from the price standards, the standard to which public utilities will be held is defined in s. 705A-6(a), Wage and Price Standards, December 13, 1978. The following computation demonstrates that with the rate relief authorized herein, WEPCO will satisfy the two-part limitation in that: (1) test year 1979 "profit margin" is less than the average "profit margin" for any two of WEPCO's last three fiscal years prior to October 2, 1978; and (2) test year "profit" does not exceed base-year profit by more than 6.5% plus the percentage growth in physical volume from the base year to the test year:

	Actual			Test Year
	1975 (000's)	1976 (000's)	1977 (000's)	1979 (000's)
Total Electric Revenues	$405,307	$462,691	$519,261	$661,565
Net Operating Income	$ 69,411	$ 83,171	$ 88,758	$111,514
Plus Income Taxes & Investment Tax Credit - net	25,600	26,910	47,730	44,782
"Profit"	$ 95,011	$110,081	$136,488	$156,296
"Profit margin"	23.4%	23.8%	26.3%	23.6%
Average 1976 and 1977		25.1%		
Total Revenues 12 month ended 9/30/78			$570,630	
Allowable average "profit margin"			25.1	
Base-year "profit"			$143,228	
Plus: Physical volume growth 2.9%			4.154	
6.5% by standards			9.310	
"Profit" limitation for 1979			$156,691	

[*18]

Electric Rate Design

The current electric rates are unreasonable because they are inadequate to produce sufficient revenues. Authorized rates will provide an increase in annual revenues of $50,661,000 and are shown in appendix C.

Applicant presented a jurisdictional cost-of-service study in this proceeding and four fully allocated embedded cost-of-service studies. Applicant's services include wholesale electric service and retail electric service. The Federal Energy Regulatory Commission (FERC) has jurisdiction over applicant's sales of electricity at the wholesale level. The Michigan Public Service Commission regulates the retail sales of electricity by applicant in that state, and the Public Service Commission of Wisconsin regulates the retail sales of electricity within this state. The jurisdictional study which is appropriate for this proceeding separated total system costs by regulatory jurisdiction.

The fully allocated embedded cost-of-service studies presented in this proceeding allocated those costs which are under the jurisdiction of the Public Service Commission of Wisconsin to the respective customer classes, i.e., Residential, Commercial and Industrial. In[*19] addition, the fully allocated studies allocated costs to: a) Rate area 1, applicant's service territory prior to merger with the former Wisconsin Michigan Power Company; and b) Rate areas 2 and 3, the former Wisconsin Michigan Power Company service territory.

The cost-of-service studies presented in this proceeding indicate that: a) Rate area 1 should receive less of a percentage increase than rate areas 2 and 3; and b) Customer class revenue levels require adjustment to recover the embedded cost-of-service.

The commission does not accept the embedded cost studies introduced in this proceeding as the basis to allocate class revenue requirements. In applicant's last increase proceeding for Rate Area 1 (docket number 6630-ER-2/5) the commission authorized rates based on marginal cost. Although no marginal cost studies have been introduced in this proceeding the rates authorized herein for Area 1 reflect the same marginal cost approach considered in developing the tariffs authorized in applicant's last rate proceeding, docket 6630-ER-2/5.

The authorized rates increase all customer class revenue levels in Rate Area 1 by approximately the same percentage. This equal customer class[*20] revenue increase is considered appropriate because each customer class's relative contribution to system peak has not changed since the previous rate proceeding. This action will also avoid distortion of the marginal cost based price signals of the authorized tariffs and mitigate certain customer bill impacts.

Embedded costs are based on historical averages, whereas marginal costs are the costs to supply an additional unit of electricity. While the embedded cost studies indicate that the revenues recovered from the residential class provide less than the authorized rate of return, the tariffs authorized herein provide the customer with an accurate price signal as to the cost of consuming an additional unit of electricity. It is therefore the commission's determination in this proceeding not to reallocate revenues as indicated by the embedded cost-of-service studies but to provide marginal-cost-based price signals as previously discussed.

The commission also considers it appropriate to combine, where possible, the rates in applicant's Rate Areas 2 and 3 with those in Rate Area 1. This action results in significantly higher class revenue increases in Rate Areas 2 and 3 (formerly[*21] Wisconsin Michigan Power Company) because customers in these rate areas have not received a rate increase since August 13, 1976. Customers in applicant's Rate Area 1 have received two rate increases since that time. It is considered appropriate to apply the same tariffs throughout applicant's service area so that all customers receive the appropriate marginal cost based pricing signal.

The present residential tariff Rg-1 in rate area 1 has a $3.39 customer charge and a two-step energy charge. There is presently no charge for the first 50 kWh per month and the charge for all energy in excess of 50 kWh is 2.80 per kWh in the winter and 4.20 per kWh in the summer.

In docket 6630-ER-2 the commission reduced the amount of electricity to be supplied at no charge (or, more accurately, to be paid for in the customer charge) from 100 to 50 kWh. The commission believes that customers should pay for all consumption of electricity on a per kWh basis. By eliminating that portion of the energy costs currently recovered by the customer charge, all customers will be able to compute the cost of supplying each kilowatt hour on a per unit basis.

The authorized energy charge for residential customers[*22] in rate area 1 is 3.43 per kWh in the winter and 4.96 per kWh in the summer and will apply to all consumption. The customer charge has been reduced from $3.39 to $2.10 through the elimination of recovery of energy costs for the first 50 kWh per month in this charge.

The residential time-of-day tariff Rg-2 retains the present $5.00 customer charge. The authorized energy charges maintain the differentials between seasons and time-of-day, but have been increased to recover the authorized revenue requirement.

Applicant proposed lowering the farm service Fg-1 tariff $6.15 customer charge. A customer charge of $4.00 per month is authorized herein and shown in appendix C. The present energy charge on the Fg-1 tariff is a flat rate for all usage greater than 100 kWh per month. The first 100 kWh per month is provided at no charge. As in the residential Rg-1 tariff, the authorized energy charge for customers served on the Fg-1 tariff applies to all energy consumption. The energy charge for the summer period has been increased more than the charge for the winter to reflect the increased operating cost of peak period generation.

The energy charges of the general secondary tariff Cg-1 [*23] have been increased to recover the authorized revenue requirements. The current seasonal differentials have been retained to reflect the increased cost of supplying energy during peak periods, and the customer charges have not been changed.

The commission has previously indicated its intention to eliminate the general secondary all-electric tariff Cg-3 and unlimited water heating tariff Wh-3. The rates authorized herein for customers served on these tariffs are the same as those for general secondary Cg-1 and Cg-3 customers. Applicant is in the process of installing metering equipment on those Cg-2 and Wh-3 customers using more than 30,000 kWh per month so that those customers can be transferred to the general secondary time-of-day tariff Cg-3. During the interim period prior to the installation of this metering equipment those customers presently on the Cg-2 and Wh-3 tariffs using more than 30,000 kWh per month will be transferred to the temporary tariff Cg-4.

The $200 customer charge of the rate area 1 general secondary time-of-day tariff Cg-3 and the interim tariff Cg-4 have been retained and the low voltage charge provision has been eliminated by rolling it into the demand[*24] charge.

The low voltage provision has caused customer confusion and is not necessary, since all customers on this tariff receive service at lower voltages. The authorized demand and energy charges maintain the differentials between seasons and time-of-day, but have been increased to recover the authorized revenue requirement.

The record in this proceeding supports applicant's proposal to increase the charge for each meter in excess of one from $1.00 per month to $4.00 for Cg-3 customers, and that change is authorized herein. This change is due to the differences in costs between meters which measure electricity consumption diurnally and the non-time differenciating meters previously used.

The authorized rate area 1 general primary tariff Cp-1 retains the present customer charge; the demand and energy charges have been increased to recover increased revenues. Applicant proposed changing the measured demand provision for this class from the average of two maximum weekly demands occuring during the on-peak hours in a billing period to the maximum 15-minute demand occuring during the on-peak hours within the billing period. The January 5, 1978 order in docket 6630-ER-2/5 authorized[*25] applicant to revise the measured demand from the average of the weekly measured demands to the average of two maximum weekly demands occuring during the billing period. The action taken by this commission in docket 6630-ER-2/5 was a movement in the direction of what applicant has proposed in this proceeding. The measurement of billed demand based on the maximum 15-minute demand more accurately reflects the costs of providing generation and transmission facilities for these customers. The tariffs authorized herein include this change.

In conjunction with the change in measured demand, applicant proposed changing the general primary power factor clause. The present clause uses average power factor for determining an adjustment to measured demand. Applicant proposed to use the actual power factor associated with the maximum 15-minute measured demand. The proposed power factor clause is consistent with the change in the method of determining billed demand and is authorized herein.

The rates for the general primary interruptible tariff Cp-2 currently in effect in rate area 1 are the same as those for general primary firm service, but provide a lower demand charge to reflect lower[*26] reliability service. The authorized demand and energy charges for interruptible service as shown in appendix E incorporate the increased charges authorized herein for general primary firm service but reflect lower reliability of service. In addition, applicant will be ordered herein to make this tariff available for those customers in rate areas 2 and 3 with demands greater than 1 megawatt, and contact those customers prior to the June 19, 1979 deadline established by commission order in docket 6630-ER-9 dated December 19, 1978.

The customer and energy charges for the incandescent street lighting tariff Ms-2 have been increased to recover the authorized revenue requirement. The present 6-step declining block energy charge does not accurately reflect the cost of providing service, and the tariff authorized herein contains a 3.39 flat charge for all energy used.

The rates of other tariff classifications for customers in rate area 1 (Mg-2, GL-1, Ms-1, Ms-3, Ms-4, Mg-1 and Wh-1) have been increased to recover the authorized revenue requirement. Where appropriate, the present customer charge has been retained, and the increase is recovered through the energy charge.

The present[*27] tariffs for customers in rate areas 2 and 3 (the former Wisconsin Michigan Power Company) which have been in effect since August 13, 1976 have declining block energy charges. This feature has been eliminated in the authorized tariffs. Customers currently receiving service on the Rg-1, Rw-1, Fg-1, Cg-1, (using more than 30,000 kWh per month) and Cp-1 tariffs will be charged the same rates as customers on comparible tariffs in the rate area 1 territory. The present residential service tariff Rg-2 has been eliminated and those customers have been placed on the Rg-1 tariff.

Applicant proposed that farm customers served on the all-electric tariff Fg-3 be transferred to the residential all-electric tariff Rg-3. Applicant further proposed to close this tariff to new customers six months after the effective date of this order. The tariff for residential all-electric and farm all-electric customers authorized herein is an adoption of applicant's proposal to combine these two service classifications. However, applicants request for a six-month delay before closing these tariffs is rejected. The commission would be remiss in its duty if, knowing that this tariff will be eliminated in [*28]future rate cases, it allowed all-electric customers to attach to applicant's system with the expectation of reduced tariffs. The authorized tariff is closed to customers who have not made application for service as of the effective date of this order.

The present general secondary Cg-1 tariff in rate areas 2 and 3 has a fixed charge of $5.50 and a declining block commodity charge. Customers having similar operating characteristics in applicants rate area 1 service territory receive service under either a time-of-day tariff or a flat energy rate with a $7.50 customer charge for single phase service and a $15.00 customer charge for three phase service. Customers on the time-of-day tariff have monthly consumption in excess of 30,000 kWh per month.

Applicant proposed placing those general secondary Cg-1 customers in rate areas 2 and 3 who have consumption in excess of 30,000 kWh per month (approximately 235 customers) on a time-of-day tariff which is identical to the corresponding tariff in rate area 1. Applicant is authorized to begin installation of the necessary metering equipment and to place these customers on time-of-day tariffs. While this procedure is being implemented, [*29] those Cg-1 customers in rate areas 2 and 3 with consumptions in excess of 30,000 kWh per month not receiving service on the time-of-day tariff will be placed on a temporary tariff Cg-4.

To more appropriately reflect cost, the commission has authorized a tariff herein for those general secondary Cg-1 customers in applicant's rate areas 2 and 3 with consumptions less than 30,000 kWh per month which contain a customer charge of $7.50 for single-phase service and $15.00 for three-phase service. The present declining-block rate structure for these customers has been eliminated and a flat rate is authorized to provide these customers with an appropriate cost-based price signal. The flat energy rates authorized for this class of customer have not been increased to the level of the corresponding tariff in rate area 1 because of bill impact considerations.

Applicant proposed increasing the customer charge of the rate areas 2 and 3 general secondary total electric tariff Cg-3 from $37.00 to $43.75. Applicant also proposed a flat energy charge, and that this tariff be closed to new customers six months after the date of this order.

The rates authorized herein for rate area 2 and 3 general[*30] secondary total electric Cg-3 customers is a movement in the direction of eliminating this tariff. These customers will be placed on the Cg-1 or time-of-day tariff when time-of-day metering installation is completed for all customers whose consumption exceeds 30,000 kWh per month. The customer charge has been reduced to $7.50 for single-phase service and $15.00 for three-phase service and the energy charges have been flattened. For the reasons previously stated regarding the closing of all electric tariffs, the authorized tariff is closed to customers who have not made application for service as of the effective date of this order.

.The commission authorizes herein mandatory time-of-day rates for those general primary Cp-1 customers in rate areas 2 and 3. The authorized energy and demand charges are flat for both the winter and summer periods, and the on-peak energy charge is twice the off-peak energy charge. The tariff for these customers is identical to the comparable tariff in applicants rate area 1.

The customer and energy charges for the rate areas 2 and 3 incandescent street lighting tariff Ms-1 have been increased to recover the authorized revenue requirement. A customer[*31] charge of $4.75 and a flat energy charge of 3.38 is authorized thereby eliminating the present 6 step declining block tariff structure.

The rate areas 2 and 3 street and area lighting tariffs Ms-2, Ms-2.1 and Ms-3 have been increased to recover the authorized revenue requirement.

The current minimum charges for major rate classifications, excluding general primary customers, include a charge for some kilowatt hours whether energy is used or not. On cross examination, applicant's witness indicated that the function of the minimum charge was to insure the recovery of customer costs. Applicant did not propose a substantial increase in the customer charges, and actually proposed lowering this charge for some customers.

The authorized minimum charges will reduce or hold constant the bills of low usage customers without adversly affecting the revenue stability of applicant. A minimum charge of $5.00 is authorized herein for those customers served on the Rg-1 tariff in rate area 1. The $5.00 minimum charge shall also apply to customers served on the Rg-1 and Rg-3 tariffs in rate areas 2 and 3. The present minimum charge for general primary customers is based on a contracted amount[*32] of demand, and is considered appropriate in this proceeding. For all other rate classifications, the authorized minimum charge is the customer charge.

Applicant proposed to provide mandatory residential time-of-day tariffs to an additional 3,000 customers. At present, mandatory time-of-day tariffs are applicable to the 577 largest residential customers; their average monthly consumption exceeds 3,200 kWh. Under applicants proposal, the 3,000 additional customers would be the largest residential energy users during calendar year 1978, not including those already on mandatory time-of-day tariffs. Mandatory time-of-day tariffs would then apply to residential customers exceeding approximately 3,000 kWh per month.

Applicant proposes to evaluate the cost benefits of residential time-of-day rates independent of and in conjunction with direct load controls, and to evaluate the reliability of metering equipment by installing at least five different types of meters for these 3,000 customers. Under applicant's proposal each of five different groups of customers would receive a different type meter. In order to fully evaluate the effects of time-of-day pricing and direct load control devices, [*33] applicant proposes that these residential customers be prohibited from utilizing the tariff of the controlled water heating program authorized by this commission in docket 6630-CF-12.

Applicant is authorized herein to purchase the necessary metering equipment and begin placing the largest residential consumers on time-of-day tariffs. The commission accepts applicant's proposal to prohibit the application of water heater load control in order to determine the impact of time-of-day tariffs on system demand.

Applicant will be ordered herein to submit a detailed plan to implement this time-of-day/load management research report. This report should describe the type of meters being installed on these 3,000 residential customers, the coincident peak contribution and annual megawatt-hour consumption of these customers, a plan for installation of metering equipment, and a summary of how it will evaluate the cost benefits of residential time-of-day tariffs and direct load controls. This report shall be submitted within 30 days of the effective date of this order.

In addition to the mandatory time-of-day tariff proposals discussed above, applicant proposed optional time-of-day tariffs [*34] for a maximum of 100 customers who use some form of renewable energy. These customers would rely on applicant as a backup to alternative energy systems which would operate during the on-peak period. The commission directs applicant to submit proposed tariffs for commission consideration.

Applicant proposed a change in its fossil production adjustment clause (FPAC) to reflect the costs of generation from all energy sources. In view of the escalating costs associated with the production of electric energy, it is reasonable and just that nuclear generation costs be included in the calculation of this clause. The revised FPAC authorized herein and shown in appendix D includes a fuel base cost of 1.196 per kWh.

Environmental Screening

The proposal to increase applicant's electric rates is classified as a Type II action under s. PSC 2.90(2)(e), Wis. Adm. Code. Staff prepared an environmental screening and concluded that no significant environmental impact was likely to result from the proposal. The preparation of an environmental impact statement is, therefore, not required. Nonetheless, staff did note in the screening the need for continuing evaluation of decommissioning policy, [*35]particularly in the light of federal policy reformulation which is presently underway and in which the commission intends to participate. Additionally, the generic subject of the treatment of construction work in progress will be addressed in separate proceedings ordered by the commission.

Rates and revenues authorized in this order are based on test year 1979; two months of that year have already passed. In order to afford the applicant a reasonable opportunity to earn the return authorized, it is necessary that this order be placed into effect at the earliest practicable date.

Ultimate Findings of Fact

THE COMMISSION FINDS:

1. That operating income of applicant applicable to retail electric utility operations for the test year 1979 at existing rates is $82,425,000.

2. That average net investment rate base applicable to retail electric utility operations for the test year 1979, is $971,481,000. Such rate base is reasonable and just.

3. That the earned rate of return for retail electric utility operations for the test year 1979 at existing rates is 8.48%.

4. That the composite cost of capital rate of Wisconsin Electric Power Company for the test year 1979, with capitalization[*36] ratios of 40.0% common stock, 10.0% preferred stock, 46.0% long-term debt and 4.0% short-term debt, with a 13.25% earnings requirement on common stock equity, is 9.85%. Such percentage is a reasonable and just return on capital.

5. That after adjustment for the ratio of net investment rate base to capital applicable primarily to such rate base of 103.12%, adjustment for the effect of cost of capital on construction work in progress, and a .05% adjustment for allowance for miscellaneous corporate expenses, a percent return rate applicable to net investment rate base to provide an overall cost of capital rate of 9.85% is 11.09%. Such percent is a reasonable and just return on average net investment rate base.

6. That on the basis of the aforesaid findings of fact, applicant's revenue requirement for Wisconsin retail electric utility operations for the test year 1979 to produce a return of 11.09% on average net investment rate base is $614,376,000.

7. That presently authorized tariffs for electric utility service will produce Wisconsin retail operating revenues of $563,715,000 for the test year 1979, which falls short of the above revenue requirement by $50,661,000.

8. That[*37] the revenue shortage of $50,661,000 is applicable to retail electric service in Wisconsin under jurisdiction of this commission. Present tariffs of applicant for electric operations are unreasonable and unjust because the revenues produced therefrom are inadequate.

9. That the tariffs authorized herein for retail electric service, will produce an increase in annual Wisconsin retail electric service revenues of $50,661,000 based on estimated customers and usage for the test year 1979. Such tariffs are reasonable and just.

Conclusion of Law

THE COMMISSION CONCLUDES:

That the commission is empowered by ss. 196.03, 196.20, 196.37 and 196.40, Wis. Stats., to authorize applicant to establish tariffs in accordance with the above findings of fact; and that such an order should be issued.

Order

THE COMMISSION THEREFORE ORDERS:

1. That Wisconsin Electric Power Company be and it hereby is authorized to substitute for its existing tariffs for electric service the tariffs contained in appendices C, D, E, F and H attached hereto and made a part hereof. The effective date of this order shall be 7 days after mailing to, or physical service upon, the parties to the proceedings. The authorized[*38] tariffs shall also be effective on that date, provided that the newly authorized tariffs are filed with the commission and placed in all offices and stations of the utility prior to or on that date. If the newly authorized tariffs are not placed in all offices and stations by that date, the tariffs will become effective on the date that they are placed in all offices and stations. The utility shall immediately inform the commission, in writing, of the date that the authorized tariffs take effect.

2. That Wisconsin Electric Power Company shall prepare bill inserts which appropriately identify the tariffs authorized herein. A copy of such insert will be submitted to the commission for information. Distribution of said insert shall be made to customers with the first billing which contains the tariffs authorized herein.

3. That Wisconsin Electric Power Company be and it hereby is authorized to purchase the necessary metering equipment and begin placing the 3,000 largest residential customer during 1978 (not already on time-of-day tariffs) or successor customers at the same premises on mandatory time-of-day tariffs.

4. That Wisconsin Electric Power Company shall submit to the[*39] commission within 30 days of the effective date of this order, a plan for implementation of the study regarding the cost benefits of residential time-of-day tariffs and direct load controls as outlined in the preceeding findings of fact.

5. That Wisconsin Electric Power Company shall submit for commission consideration proposed optional time-of-day tariffs for customers using some form(s) of renewable energy.

6. That Wisconsin Electric Power Company contact those general primary customers in rate areas 2 and 3 with demands greater than 1 megawatt by June 19, 1979, and submit a report to the commission summarizing customers responses to interruptible tariffs by August 19, 1979.

Concurring opinion of Chairman Charles J. Cicchetti and opinion of Commissioner John C. Oestreicher dissenting in part attached hereto.

CONCURBY: CICCHETTI

CICCHETTI, concurring

CONCURRING OPINION

Since becoming Chairman this decision is the first time I have participated in changing the rate of return for a major utility. As such, I feel it merits some discussion.

Before I joined the Commission, economic conditions were such that the rate of return had been raised by my predecessors. Since all utilities faced [*40]high interest charges, rising energy and construction costs, the once ceiling rate of 13 percent became a new floor for every major electric and gas utility. Further, as economic conditions worsened, past commissions adopted "attrition allowances," "make-whole procedures" and "interim relief." Additional accounting adjustments were also made to improve the likelihood of earning the authorized rate of return.

After I joined the Commission my colleagues and I continued to sanction these practices. At the same time I argued that it would be better to make any such adjustments special, if not extraordinary, to be used only when a particular situation required them. As part of my plan I also believed, that the "institutionalized" 13 percent rate of return on common stock equity, should be abandoned. It has been my intention to use several criteria, which I will address below, to determine the proper level of earnings for utility stockholders on a case by case basis. In my view, breaking the 13 percent barrier, as we have done in this case, does not mean creating a new floor at 13 1/4 percent, or some other higher figure. Instead, it means that utilities which, either by managerial[*41] decision or regulatory obligation, achieve certain established targets benefitting the people of Wisconsin, should receive higher rates of return. Meanwhile, those utilities that do not perform as well will receive lower rates of return. Currently, I consider the appropriate range of rate of return on equity for Wisconsin gas and electric utilities to be from 12% to 13 1/2%. This means the average return on all utility investment will be about 9%.

By breaking the 13 percent barrier in this order, I feel we will have established a climate conducive to further adjustments in both directions for other Class A utilities in Wisconsin. Needless to say, the criteria that each Commissioner establishes and which, therefore, are reflected in the way the full Commission sets rate of return, should be explained. All interested observers should be able to understand the basis for any differences in rates of return which are established among utilities. In my opinion such straightforward explanations will be far better than the existing practice of adjustments through the sometimes uneven applications of the existing methods already mentioned above. Accordingly, I will now outline the[*42] criteria that I believe to be important for determining the rate of return on common stock equity.

(1) A utility that carries a small percent of equity relative to its debt and preferred stock is holding down the before (and after) taxes cost of capital for its ratepayers. These firms should expect a higher than average rate of return.

Conversely, generally speaking, utilities having more than an average percentage of equity finance should expect lower rates of return because they are causing higher costs of capital for their ratepayers. In Wisconsin we regulate stock and bond issuances. Nevertheless, the end result of past regulatory and management decisions should not in my opinion be overlooked in setting currently regulated returns on equity. Wisconsin Electric has passed this first test due to its relatively small percent of equity finance.

(2) All Class A gas and electric utilities in Wisconsin are intimately aware of the pricing and tariff principles adopted by the Commission in the 1974 Madison Gas and Electric case. The Commission has reiterated its support of those principles both for electric and gas pricing in the past two years. While some utilities have warmed[*43] to the task of major tariff reform, others have insisted that it is too risky to allow too large a portion of their estimated revenue requirements to be subject to the whims of free market price signals based upon economic efficiency. Regulation has undoubtedly pushed each utility faster than it wanted.to go. But some still have a longer way to go.

Further, some utilities still add needless delays to our regulatory and environmental review process by defending "old guard" outdated tariff policies. Some still add delays that slow down our staff's attempts to get data necessary to calculate marginal costs and assess environmental impacts. Such delays are often accompanied by requests for attrition allowances and/or interim relief. Utilities who, for whatever reason, contribute to a delay in the adoption of marginal cost based tariffs, should accept the fact that their preference for a more certain gross revenue target at the expense of more secure earnings for their stockholders and better choices based upon proper price signals for their customers, will mean that I will vote for lower rates of return because such utilities are less risk oriented and inert. In my opinion, if[*44] the Chief Executive Officers and Boards of these utilities understand such Commission actions, I firmly believe more responsive tariff departments will be developed as a high priority by utilities who receive lower rates of return.

(3) Utilities should no longer as a general rule expect me to approve attrition allowances and interim relief. These are exceptional treatments that I will support only when the situation warrants them. Rate design delays caused by a utility company should therefore not be rewarded either with these specific forms of adjustment or with rates of return in the upper part of the 12 to 13 1/2 percent range. Since Wisconsin Electric has shown good performance in the area of rate design, I voted to increase their rate of return in this proceeding.

In this opinion I have stated formally what I will consider when it comes to setting the rate of return. This case breaks the log jam. It raises issues that we have heretofore not debated because the return was always just 13 percent, and that was that. As a message to the financial community it is perhaps fortunate that this first break from past practices came out above 13%. It makes what I have said above[*45] sound more credible. I hope, however, our consumer critics will for once be patient, and at least take a "wait and see" attitude for the downward rate of return adjustments that I will propose to my colleagues for those utilities that fail my criteria as enunciated above.

There are two additional specific WEPCO considerations that I will also address. Raising the return for WEPCO by a quarter of a percent means an opportunity is created for a little less than two million dollars per year in additional revenue to be collected by WEPCO. This amount is less than the one time stockholders' losses for the write-off of no longer useful investments made in the now-abandoned Koshkonong nuclear power plant as tentatively approved by the Commission. More importantly, the two million in increased revenue authorization will on a yearly basis be offset by nearly twice the reduction in annual cost (almost $4 million per year).

As the result of a full implementation of 100 MW of interruptible industrial load we ordered in 6630-ER-9, WEPCO will save ratepayers almost twice as much (nearly $4 million per year) as this additional return (about $2 million per year). I put this matter in my opinion[*46] because I have been informed of some rather negative promotion of this new interruptible electric service by employees of WEPCO. This concern of mine should come directly to the attention of the Chief Executive Officer of WEPCO. Failure to amend any such employee attitudes could easily lead me to reverse my upward adjustment in rate of return, which is at least partially based upon the achievement of improved load factors, more price signals, and greater reliance on economic efficiency in WEPCO's tariff policy.

Finally, there has been incredible confusion in 6630-ER-1, 6630-ER-2/5 and in this proceeding, 6630-ER-8, over the allocation of revenue requirements and revenue increases to various customer categories. There are more than 30 accounting procedures for allocating costs. Each customer category can hire one or more consultants to argue that their clients belong to a group that is paying and has been paying too much. Other customer categories, if they had similar resources for consultants, could do the same thing.

Further confusion has arisen from the fact that some believe that "coincident peak cost allocations" of imbedded accounting costs and marginal cost based tariffs[*47] are inextricably tied together. It is, therefore, incorrectly alleged that the one "true" method for allocating costs among customer categories for a commission that has adopted marginal cost is the coincident peak cost allocation. This link is not required by theory, common sense, economic efficiency or anything else. A commission must decide each of these questions separately until all customers are placed on time of use pricing. At that point the only difference in basic prices will be voltage adjustments. Until that day, which I believe to be in the forseeable future in Wisconsin (certainly before 1985), the Commission must regulate revenue allocation among categories.

In analyzing what has happened in the WEPCO service area since 6630-ER-2/5, I cannot find a significant change in peak responsibility among classes for 6630-ER-8. Therefore, in my judgment an equal across-the-board increase in revenues from each customer category, after folding the Wisconsin Michigan Power Company rates into WEPCO's rates, is the best way to collect increasing fuel, interest, labor, construction, and other costs. To claim any group has not contributed equally is to draw a conclusion from[*48] an incorrect assumption that there is "one" true cost allocation method, consistent with marginal cost principles. I cannot do this, and reject any attempt to force me to do it. I may believe that there is one method for determining marginal cost, but this has almost nothing to do with the cost allocation debate among customer categories.

In the future for WEPCO I continue to look for more load management, and more residential time of use pricing (either mandatory for large volume residential customers, or optional with an inverted summer electric rate as the alternative). WEPCO has made progress. Advertising and charitable and lobbying contributions have been eliminated except for conservation and safety advertisements. Tariff reform has moved quickly, and the utility is well managed and healthy. A 13 1/4 return is justified and I enthusiastically support it.

Charles J. Cicchetti, Chairman

DISSENTBY: OESTREICHER

OESTREICHER, dissenting

DISSENTING OPINION

In Docket No. 6630-ER-2 and 6630-ER-5, a predecessor case resulting in an interim order herein, I wrote an opinion with regard to the rate design adopted during the interim. I concurred in that interim order because I believed that [*49]over all the rates adopted therein were a major improvement in rate design for this company. This order further improves the rate design about which I expressed reservations in 6630-ER-2/6630-ER-5.

I further concur the treatment of decommissioning expenses adopted by the Commission herein.

I disagree with increasing the allowed return on common stock equity above 13 percent for this company at this time. It is because the Commission has increased the allowable return on common stock equity above 13 percent that I am compelled to withhold my support for this order.

John C. Oestreicher, Commissioner

WISCONSIN ELECTRIC POWER COMPANY

Appendices

Appendix A	Appearances
Appendix B	Electric Revenue Comparison
Appendix C	Electric Rate Comparison
Appendix D	Fuel Adjustment Clause
Appendix E	General Primary - Interruptible Tariff
Appendix F	General Primary - Determination of Demand
Appendix G	Electric Bill Comparison
Appendix H	General Primary - Conditions of Delivery