BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

Case No. ER-82-39

In the matter of Missouri Public Service Company of Kansas City, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the Company.

Case No. WR-82-50

In the matter of Missouri Public Service Company of Kansas City, Missouri, for authority to file tariffs increasing rates for water service provided to customers in the Missouri service area of the Company.

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APPEARANCES: JAMES C. SWEARENGEN, Attorney, and W. R. ENGLAND, III, Attorney, Hawkins, Brydon & Swearengen, P.C., P.O. Box 456, Jefferson City, Missouri 65102, for the Missouri Public Service Company.

JOHN E. BURRUSS, JR., Attorney, Hendren & Andrae, P.O. Box 1069, Jefferson City, Missouri 65102, for the City of Clinton, Missouri.

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THOMAS R. PARKER, Deputy General Counsel, MARY ANN GARR, Assistant General Counsel and HOLLY E. PECK, Assistant General Counsel, P.O. Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

## REPORT AND ORDER

On July 31, 1981, Missouri Public Service Company (hereinafter, "Company") submitted to the Public Service Commission of Missouri revised tariffs designed to increase the Company's rates for electric service provided to customers in its Missouri service area, bearing a proposed effective date of September 3, 1981. The revised tariffs were designed to increase Company's billed jurisdictional electric revenues by approximately $26,700,000 annually, exclusive of franchise and occupational taxes. By its "Suspension Order" issued August 18, 1981, in Case No. ER-82-39, the revised electric tariffs were suspended from September 3, 1981 until January 1, 1982, unless otherwise ordered by the Commission. On October 1, 1981, the Commission issued its "Second Suspension Order and Notice of Proceedings" in Case No. ER-82-39, further suspending the effective date of the revised electric tariffs from January 1, 1982 until July 1, 1982, unless otherwise ordered by the Commission.

On August 14, 1981, Company submitted to the Commission revised tariffs designed to increase Company's rates for water service provided to customers in its Missouri service area, bearing a proposed effective date of September 14, 1981. The revised water tariffs were designed to increase Company's billed jurisdictional water revenues by approximately $421,000 annually, exclusive of franchise and occupational taxes. By its "Suspension Order" issued August 26, 1981 in Case No. WR-82-50, the Commission suspended the revised water tariffs from September 14, 1981 until January 12, 1982, unless otherwise ordered by the Commission. On October 1, 1981, the Commission issued its "Second Suspension Order and Notice of Proceedings" in Case No. WR-82-50, further suspending the revised water tariffs from January 12, 1982 until July 12, 1982, unless otherwise ordered by the Commission.

On September 3, 1981, Company withdrew two of its revised electric rate tariffs previously filed with the Commission in Case No. ER-82-39, which pertained to the electric space heating rate.

The Second Suspension Order issued in each of these cases (ER-82-39 and WR-82-50) joined the two cases for hearing, and established deadlines for the filing of applications to intervene, the filing of prepared direct testimony and exhibits, and the filing of rebuttal testimony and exhibits, as defined in said Second Suspension Orders. Those Orders also directed the Company to give notice of these cases to the Company's customers by an imprint on a bill or a bill insert no less than fifteen (15) days, and no more than forty-five (45) days, before the hearing of these cases, unless otherwise ordered by the Commission, and required the Company to submit its proposed form of notice to the Commission for approval in advance. The Second Suspension Orders also set these cases for prehearing conference from March 1 through March 5, 1982, and for hearing from March 15 through March 26, 1982, in the Commission's hearing room in Jefferson City.

By Order issued October 20, 1981, the Commission changed the dates of the hearing in these cases to March 8 through 19, 1982.

The Second Suspension Order in Case No. ER-82-39 granted leave to intervene to the Missouri Public Interest Research Group (MoPIRG). By Order issued November 10, 1981, the Commission granted leave to the City of Clinton, Missouri and the City of Osceola, Missouri to intervene in Case No. WR-82-50. By Order issued December 29, 1981, Trans World Airlines, Inc. was granted leave to intervene in Case No. ER-82-39.

On November 2, 1981, the Commission issued its "Order Setting Local Hearings" in these cases, setting local public hearings to be held at 1:00 p.m. and 7:00 p.m. on Thursday, February 18, 1982 in Clinton, Missouri, and at the same times on Friday, February 19, 1982 in Raytown, Missouri. By its Order issued December 29, 1981 in these cases, the form of notice to be given by the Company to its customers of the hearings in these cases was approved by the Commission. An Order Modifying Notice to Customers was issued on January 5, 1982, which Order changed the location of the local public hearing in Clinton, Missouri from the Henry County Courthouse to the Civic Center in the City of Clinton. Prepared direct testimony and exhibits were timely filed by the parties to these cases in accordance with the Commission's orders.

On Thursday, February 18, 1982, local public hearings were held as scheduled at 1:00 p.m. and 7:00 p.m. at the Civic Center in the City of Clinton, Missouri. On Friday, February 19, 1982, local public hearings were held as scheduled at 1:00 p.m. and 7:00 p.m. in the City Hall of Raytown, Missouri. Public testimony was taken at all of such hearings, and has become a part of the record of this case.

On March 1, 1982, pursuant to Commission Order, a prehearing conference in these cases was convened, in which representatives of the Company, the Staff of the

Public Service Commission (hereinafter, "Staff"), the Office of the Public Counsel (hereinafter, "Public Counsel"), the City of Clinton, and Trans World Airlines, Inc. (hereinafter, "TWA"), participated. Neither the City of Osceola nor MoPIRG appeared at or participated in the prehearing conference.

The hearing of these cases commenced in the Commission's hearing room in Jefferson City, Missouri, as scheduled, on Monday, March 8, 1982. The same parties which participated in the prehearing conference also participated in the hearing in this case. The City of Osceola and MoPIRG did not appear at or participate in the hearing. The hearing concluded on March 19, 1982. At the conclusion of the hearing, a briefing schedule was established. The reading of the record by the Commission pursuant to Section 536.080, RSMo 1978, has not been waived.

At the hearing of these cases, ruling was reserved on two motions: a motion by the Staff to reopen its direct case on the Clinton Feeder Line issue, and a motion by the Staff to strike the testimony of Company witness Sanders on the issue of the Peabody settlement. By Order issued April 14, 1982, the Commission granted the Staff's motion to reopen its direct case on the issue of the Clinton Feeder Line, and denied the Staff's motion to strike the testimony of Company witness Sanders on the Peabody settlement issue. In response to that Order, the Company requested on April 15, 1982 that the Commission receive in evidence the rebuttal testimony of Company witness Kasper on the Clinton Feeder Line issue. On April 20, 1982, that rebuttal testimony of Company witness Kasper was refiled with the Commission with the witness' affidavit. By its "Order Concerning Exhibit" issued April 27, 1982, said rebuttal testimony of Mr. Kasper on the Clinton Feeder Line issue was received in evidence in this case.

## Findings of Fact

The Public Service Commission of Missouri makes the following findings of fact, based upon the competent and substantial evidence upon the whole record:

## I. The Company

Missouri Public Service Company ("Company" or MoPub") is a public utility corporation duly organized and existing under the laws of the State of Missouri. The Company is an electric, gas and water corporation as defined in Chapters 386 and 393, RSMo 1978, with its administrative offices and principal place of business located at 10700 East 350 Highway, Kansas City, Missouri. It is engaged in the generation, transmission, distribution and sale of electric energy, as well as in the furnishing of water service and natural gas service, within its authorized Missouri service areas and under the jurisdiction of this Commission.

## II. Elements of Cost of Service

The Company's authorized rates are generally based on its cost of service or its revenue requirement. As elements of its revenue requirement, the Company is authorized to recover all of its reasonable and necessary operating expenses and, in addition, a reasonable rate of return on the value of its property used in public service. It is necessary, therefore, to establish the value of the Company's property and to establish a reasonable return to be applied to the value of its property or rate base which, when added to the allowable operating expenses, results in the total revenue requirement of the Company. By calculating the Company's reasonable level of revenues, it is possible to mathematically calculate the existence and extent of any deficiency between the present earnings and any revenue requirement determined to be allowable in this rate proceeding.

## III. The Test-Year/True-Up

The purpose of using a test-year is to create or construct a reasonably expected level of revenues, expenses and investment during the future period during which the rates, to be determined herein, will be in effect. All of the aspects of the test-year operations may be adjusted upward or downward to exclude unusual or unreasonable items or to include unusual items by amortization or otherwise, in order to arrive at a proper allowable level of all of the elements of the Company's operations.

The parties to this case agreed to utilize, as a test-year, the twelve-month period ending September 30, 1981, as adjusted for known and measurable changes through April 30, 1982.

The parties, for purposes of this case, also agreed to utilize certain facts and account balances as of April 30, 1982, based upon a "true-up" audit of such balances after the conclusion of the hearing in this case. Such updated, or "trued-up," figures were filed in this case on June 9, 1982. The facts and account balances trued-up as of April 30, 1982 are: plant; depreciation reserve; reserve for deferred taxes; customer advances; customer deposits; fuel prices; capital structure; PSC assessment; and rate case expense.

IV. <u>Contested Issues</u>

The Commission hereinbelow sets out its findings as to those issues presented to it for decision in the Hearing Memorandum in this case, (Joint Exhibit No. 1), which were not resolved by the parties in prehearing conference.

V. <u>Net Operating Income</u>

Several adjustments to the Company's operating revenues and expenses have been proposed. Generally, adjustments to operating revenues and expenses found to be proper represent a reduction or addition to the Company's net operating income, after giving effect to income tax liability. After adjustments made on the basis of the following issues, the Commission finds Company's net electric operating income under present rates to be $23,844,039. Net water operating income is set out under section IX. C., below.

A. <u>Electric Power Research Institute (EPRI)</u>

Staff and Public Counsel propose to disallow that portion of Company's operating expenses representing the Company's assessment for EPRI dues. EPRI (Electric Power Research Institute) is a non-profit scientific research institute sponsored by the electric utility industry of the United States. The function of EPRI is to plan, fund and manage a nationwide coordinated research and development (R & D) program for the electric utility industry. The objective of EPRI is to develop new and improved ways of generating, transmitting, distributing and utilizing electric power, to help insure the availability of an adequate supply of cost effective, reliable and environmentally acceptable electricity. EPRI is funded through contributions (dues) from member companies.

EPRI projects of actual and projected benefit to the Company and its customers have been enumerated at great length upon the record of this case, as they have been in a number of other recent cases before the Commission. Those projects include developing methods for the disposal of PCBs, development of single pressure circuit breakers and metal oxide surge arrestors, development of methods for transformer noise suppression and for design and analysis of laterally loaded drilled piers, development of new methods and chemicals to control regrowth in trees, development of gas vapor and fire resistant transformers, development of a methodology to be utilized in the determination of the size of concrete foundations used with steel transmission poles, and others.

The Commission has held on innumerable past occasions, and continues to hold, that electric research and development, which can benefit both the companies and their customers, is a necessary function in this age of rapidly advancing technology. Electric research and development, however, is too expensive an undertaking for any one company standing alone. Thus, the most effective and efficient approach to electric research and development is through the pooling of resources, as is accomplished by the member-companies of EPRI.

It is clear that the Company in this case has met its burden of proving that its participation in EPRI is designed to produce, and does produce, direct benefits to the Company and its ratepayers. The Company's evidence on this issue is comparable to that found sufficient by the Commission in Re: Missouri Power & Light Company, P.S.C. Case No. ER-80-286 (March 13, 1981), and in Re: Kansas City Power & Light Company, P.S.C. Case No. ER-81-42 (June 17, 1981). As in those cases, the Commission notes that there is no guarantee of the success of any research and development project. Further, some research and development projects of EPRI produce more easily quantifiable results than others. Even research and development projects which lead to seeming "dead ends" result in increased knowledge on the part of EPRI and its member-utilities as to the reasonably available alternatives for improving operations.

As in every other recent case in which this kind and quality of evidence has been presented on this issue, the Commission finds herein that the potential savings to the Company and improved service to its customers justify the participation of Missouri Public Service Company in EPRI and the allowance of the EPRI assessment as an operating expense.

The Company's EPRI dues in this case will be included as an allowable expense item.

B. <u>Edison Electric Institute (EEI)</u>

Company also proposes to include in its test-year cost of service, payments by the Company to the Edison Electric Institute (EEI) in the amount of $42,816. Staff and Public Counsel argue that these dues should be excluded from the Company's test-year cost of service.

The Edison Electric Institute is a voluntary organization whose membership is made up of electric utilities throughout the United States. EEI studies and develops information concerning all aspects of the electric utility industry, including accounting, energy analysis, engineering and operation, environmental, finances and general industry relations. Most of EEI's work is done by numerous EEI committees. Several employees of the Company are members of EEI committees. The Company alleges that information brought to the Company's attention through EEI committee meetings and publications aid the Company in its operations and result in operational and financial benefit to the Company and its ratepayers.

Staff and Public Counsel propose the disallowance of EEI payments as an operating expense in this case on the basis that EEI engages in considerable lobbying activities and public relations efforts on behalf of the electric utility industry. Company submits that the true lobbying efforts of EEI represent less than two percent of the EEI budget, and are therefore so insignificant that they should not have an effect upon the allowance or disallowance of EEI dues as an expense in this case. The two percent figure, however, is based solely on the amount reported by EEI pursuant to the Federal Registration of Lobbying Act, 2 U.S.C. Section 267(a). That federal statute requires any person engaged for pay in attempting to influence the passage or defeat of any legislation by the United States Congress to register with the Clerk of Congress and to file a quarterly verified report of all money received and expended by such person during the previous calendar quarter in carrying on his work. By its own terms, the Act does not apply to any person who "merely appears before a committee of the Congress of the United States in support of or in opposition to legislation." Nor does the Federal Registration of Lobbying Act require EEI to report expenditures related to its efforts to influence the Executive Branch of the federal government, regulatory commissions and Presidential task forces, or its efforts related to its support of witnesses testifying before Congressional committees.

This Commission has defined lobbying as "an attempt to influence the decisions of regulators and legislators in general." Re: Kansas City Power & Light Company, P.S.C. Case No. ER-81-42, page 23 (June 17, 1981). The evidence in this case makes it clear that substantially more than two percent of EEI's expenditures and efforts are directed toward influencing the decisions of regulators and legislators in general. The Commission has heard this two percent argument concerning EEI's lobbying activities on numerous occasions in the past, and has uniformly rejected that argument. The Commission holds that the fact that EEI reports two percent of its expenditures as lobbying expenses under the Federal Regulation of Lobbying Act is irrelevant to the Commission's consideration of this issue.

The fact that EEI applies a substantial portion of its expenditures and efforts toward lobbying is not necessarily, however, determinative of this issue either. If testimony was adduced, for example, that showed that EEI represents the interests of electric utility ratepayers and that those acts of representation were beneficial to ratepayers, it is possible that EEI dues, or a portion thereof, could be allowed as expenses in the Company's cost of service. In Re: Kansas City Power & Light Company, P.S.C. Case No. ER-81-42, page 24 (June 17, 1981), the Commission stated the following:

> The rule has always been that dues to organizations may be allowed as operating expenses where a direct benefit can be shown to accrue to the ratepayers of the Company. Conversely, where that sort of benefit does not appear, disallowance of the dues is required. It follows that the mere fact that an activity might fall within the very broad general definition of lobbying as used by Public Counsel should not necessarily mean that it is an improper expense for ratemaking purposes. The question is one of benefit or lack of benefit to the ratepayers.

In Re: Kansas City Power & Light Company, id., the Commission found that the record was silent as to the relative benefit of EEI activities. As a result, the EEI dues of that company were not allowed in the company's cost of service. Likewise, in the instant case, benefits to the Company's customers of participation in EEI, if any, have not been quantified. As a result, the Company's EEI dues cannot be allowed in the Company's cost of service in this case.

C. Purchased Power

For purposes of calculating test-year purchased power expense, Company and Staff have agreed to the number of megawatt hours (MWH) utilized in the calculation. Company and Staff disagree, however, as to the expense or cost per MWH which should be allowed for purchased power.

Company recommends the allowance of $28.99 per MWH for purchased power expense. This number was arrived at by calculating an average cost of purchased power from January, 1980 through December, 1981, and then projecting the average purchased power cost for 1982 through mid-year 1983. Company's projection for 1982 and 1983 purchased power expense was accomplished by weighting purchased power cost escalation as follows: Fuel at 80% of the energy costs escalating at a ten percent per year rate; demand charges representing ten percent of energy charges at ten percent per year; and a percentage adder representing ten percent of energy charges at zero escalation rate; for a weighted percent increase of ten percent. Company asserts that the cost of purchased power is directly related, and very sensitive, to the cost of fuel. In applying an 80% weight to fuel in its projection, however, Company is using the highest end of its own testimony that fuel represents, on an average, 70% to 80% of the cost of purchased power.

Company also applied two other analyses to calculating the cost of purchased power. One of those methods utilizes actual purchased power data from April, May, September and October of 1981 (during scheduled maintenance outages at Sibley Generating Station), weighting those costs by the percentage of purchased power purchased from Union Electric Company (33%) and from Kansas Power & Light and Kansas Gas and Electric Company (67%). This analysis resulted in a weighted cost of purchased power of $28.48 per MWH. However, the actual data relied upon in that analysis represented only four months of one year of the Company's operations, and the dollars to which the 67% weighting was applied were the rates charged only by Kansas Power & Light. No actual cost data for purchases from Kansas Gas and Electric Company appeared in that analysis. Company asserts that its purchases from KP&L and KG&E during the major Sibley 3 outage (August, 1980 to January, 1981) cost some 10.9% higher, on average, than the cost of purchased power acquired from Union Electric Company during that time. The cost of power purchased from Union Electric Company, however, was higher than that purchased from KP&L and KG&E during 1979 and 1980.

Company's third analysis, which resulted in a cost of $28.35 per MWH, was based on an upward adjustment of 1981 purchased power costs because of the Company's characterization of 1981 as a "depressive year" in terms of purchased power costs. Company believes that most of the electric utilities from which it bought purchased power in 1981 had relatively low loads in that year, so that the power purchased by Company from those other utilities in 1981 was generated by units with lower fuel costs. Thus, according to the Company, the use of actual 1981 purchased power costs does not reflect the true trend of purchased power costs over the last several years.

The Staff annualized purchased power in three distinct components: (1) border purchases; (2) spot purchases; and (3) participation power. Border purchases relate to purchases made to supply the system border areas of Bates County, Richards and Independence, Missouri. Border purchases comprise about two percent of total annualized purchased power. Spot purchases are purchases made on a random basis from other utilities. Generally, the price includes fuel and maintenance costs, plus a profit to the seller. Participation power is power purchased in conjunction with a demand contract. In consideration of the demand charges (expressed in dollars per kilowatt hour per week), the supplying utility dedicates a portion of its system generating capacity to the purchasing utility for a stated period of time. Participation power purchases consist of an energy charge in addition to the demand charge. Depending upon the particular contract, the supplying utility will supply energy to the "best of its ability," or in certain instances the supplying utility may be obligated to seek other sources should it be unable to meet purchaser requirements with its own generation.

Staff determined the average yearly price increase from 1979 to September 30, 1981, for border purchases. For spot purchases, Staff determined the average yearly increase from 1979 through 1981, using energy charges only. Staff determined the average yearly increase for participation power from 1979 through 1981 for energy charges. For demand charges, Staff accepted Company's requirements for demand contracts with Kansas Power & Light and Union Electric, which will be necessary when the Sibley 3 unit is down for scheduled maintenance. These demand charge dollars are based on a known price per kilowatt hour per week, times three weeks in October/November, and three weeks in April. Using this analysis, Staff determined that the Company's reasonable and proper purchased power expense is $26.83 per KWH.

The Commission concludes that Staff's analysis of purchased power expense should be relied upon in this case. Staff's analysis is based upon a longer period of historical data than is the Company's. Company's characterization of 1981 as a "depressive year" also ignores the evidence that the summer peak season of 1980 was unusually hot, and that the Company experienced its greatest historical peak load during 1980.

The Commission further concludes that the Company has not met its burden of proving that Company's methodology for projecting purchased power expense can be relied upon. While some relationship between purchased power expense and fuel expense clearly exists, other important factors enter into changes in purchased power expense as well, e.g. weather and equipment outages. These other factors also clearly affect purchased power expense, but have not been adequately considered or quantified in Company's projection methodology. The Commission concludes that it cannot rely on the purchased power expense projections of the Company upon the record of this case.

The Company will be allowed an expense of $26.83 per KWH for purchased power in this case.

D. Settlement of Westinghouse Lawsuit

During the test-year, Company settled a lawsuit with Westinghouse. The net proceeds of the settlement, remaining after payment of all expenses associated with the lawsuit, amount to $398,160. Company and Staff agree that this money should be amortized back to Company's ratepayers. However, the method of accomplishing such amortization is at issue.

In June, 1969, Company brought its Sibley 3 baseload generating unit on-line. In both 1970 and 1971, turbine problems were discovered which caused the plant to be removed from service for a period of time, resulting in the incurring of extraordinary purchased power costs and maintenance expenses by the Company. Company and its insurer proceeded to file a lawsuit against Westinghouse Corporation, alleging that Company and its insurer were damaged because of the defective design, manufacture, sale, installation and service of the turbines by Westinghouse. It was this lawsuit which was settled during the test-year in this case.

Company proposes to net the $398,160 of settlement proceeds against the unamortized maintenance costs relating to the 1980 Sibley 3 generator failure (referred to above under section V. C. of these findings of fact, "Purchased Power Expense," and below under section VI. B. 2. b., "Fuel Oil Inventories at KCI, Nevada and Greenwood Generating Facilities."). The basis for Company's proposal is that the 1980 generator failure was "brought into the discussion" during the meetings with Westinghouse regarding the 1970-71 Sibley failure, and that this discussion of the additional maintenance costs relating to the 1980 Sibley failure contributed to the amount and timeliness of the settlement of the lawsuit under discussion here.

On the other hand, Staff proposes to amortize 28.9% of the extraordinary gain over seventeen years, and the other 71.1% of the extraordinary gain over two years. This proposal is based upon the relationship between the Company's actual costs incurred for extraordinary purchased power (71.1%) and other maintenance and litigation costs (28.9%). Staff's proposed amortization schedule is similar to the one used to amortize the Company's extraordinary loss resulting from the Sibley 3 generator failure, in Case No. ER-81-85. Staff submits that the extraordinary gain resulting from the Westinghouse settlement should be treated in a manner consistent with the extraordinary loss experienced as a result of the Sibley 3 failure. Staff considers its proposed treatment to be a conservative one, which avoids having the entire amount of the settlement being used in one year as an offset to revenue requirement. Staff further submits that, under its proposal, the ratepayer receives the dollar benefit of the extraordinary gain over the amortization period, and that the ratepayer will not receive the benefit of a return on the unamortized balance because the Staff is not proposing that such amounts be used to reduce rate base in this case or in the future.

In Case No. ER-81-85, Staff proposed that the Company be allowed to amortize the extraordinary puchased power costs associated with the outage of the Sibley 3 generating unit, over a period of two years, and that the Company be allowed to amortize the extraordinary maintenance costs associated with the same outage, over a period of eighteen years (the remaining useful life of the plant). Staff submitted in Case No. ER-81-85 that its proposal would avoid having the entire loss from the Sibley 3 generator failure included in rates in one year, which would have made the ratepayers' rates abnormally high for that year; would allow the stockholder to recover the entire dollar amount of the loss over the amortization period; and would not allow the stockholder a return on the unamortized deferred debit because it was not allowed in rate base. Staff's proposal in Case No. ER-81-85 was agreed to by the Company as part of a stipulated settlement of that case, which was approved by the Commission.

In Case No. 17276, effective April 19, 1972, this Commission allowed the Company to recover extraordinary purchased power costs and maintenance expenses resulting from the 1970-71 turbine failures at Sibley, through amortization. In Case No. 18180, effective June 13, 1975, the Commission allowed Company to recover $50,000 per year for litigation costs related to the Westinghouse suit. Company was also allowed to book to plant-in-service, labor and materials received from Westinghouse in 1970 and 1971 for which, because of the litigation settlement in question here, Company now does not have to pay. As a result of the settlement, Company has collected a return and depreciation expense on certain plant in which Company has no investment. These amounts have been included in the determination of the net gain resulting from the Westinghouse settlement ($398,160).

The Commission concludes that Staff's recommended schedule of amortization of the net gain from the Westinghouse settlement should be adopted. It is clear that Company's proposal would be inconsistent with the treatment agreed to by the Company, and approved by the Commission, in Case No. ER-81-85 concerning extraordinary losses from the 1980 Sibley 3 generator failure, and would work to the unfair detriment of the Company's ratepayers. It would be totally inconsistent for the shareholder to get a rapid return of his moneys in the case of an extraordinary loss, and yet not afford the same opportunity to the ratepayer for an extraordinary gain in the form of net proceeds from this settlement. Staff's proposed amortization is consistent with the treatment of extraordinary losses in Case No. ER-81-85, and is just and reasonable. The fact that the 1980 Sibley generator failure was "brought into the discussion" in settlement negotiations with Westinghouse regarding the 1970-71 Sibley failures is in no wise persuasive or dispositive of the issue. Staff's proposed treatment is hereby adopted.

E. Settlement of Peabody Coal Company Lawsuit

During the test-year used in this case, Company also settled a lawsuit which it had maintained against the Peabody Coal Company. According to the Staff's computation, explained below, the Company has received a net extraordinary gain of $1,211,734 as a result of this settlement. Staff proposes that this amount be amortized over a two-year period. Accordingly, "Other Electric Income" would be increased by $605,867 in each of the next two years. Company opposes Staff's proposal to include any amount in test-year revenues based upon the Peabody settlement.

Peabody Coal Company was under contract to supply coal to MoPub for a ten-year period commencing on the first day of commercial operation of MoPub's Sibley Unit No. 3. The actual date of commencement of commercial operation of Sibley 3 was June 13, 1969. The contract in question was entered into on December 22, 1967. On May 6, 1975, Peabody threatened to discontinue shipments of coal as of July 6, 1975, unless MoPub agreed to pay an additional $3.17 per ton over and above the price set by the 1967 contract, retroactive to January, 1975.

On May 23, 1975, MoPub filed a lawsuit against Peabody in the Jackson County Circuit Court (16th Judicial Circuit of Missouri), seeking (1) an injunction to keep in force the existing coal contract, and (2) actual damages in the amount of $30,000,000 and punitive damages, for breach of the contract.

On July 1, 1975, the Circuit Court of Jackson County entered an injunction preventing Peabody from discontinuing coal shipments under the contract. After trial, the Circuit Court entered its decree of specific performance, requiring Peabody to carry out the contract. Peabody appealed the decree of the Circuit Court, which was subsequently affirmed by the Missouri Court of Appeals on January 29, 1979. Missouri Public Service Company v. Peabody Coal Company, 583 S.W.2d 721 (Mo.App.W.Dist. 1979). Rehearing, and transfer to the Missouri Supreme Court, were denied by the Court of Appeals. The Supreme Court of the United States denied Peabody's writ of certiorari at 444 U.S. 865 in October, 1979. The action for actual and punitive damages was subsequently settled, on July 29, 1981, which settlement is the subject of the instant issue.

A second dispute between MoPub and Peabody arose out of MoPub's audit in 1979 of the cost of certain coal supplied by Peabody to MoPub. Beginning in April, 1978, MoPub began charging Account 151--"Fuel Inventory," and crediting a liability account (232.9) for certain amounts billed by Peabody which MoPub refused to pay. Between April, 1978 and August, 1979, MoPub recorded a liability for unpaid charges from Peabody in the amount of $4,888,145.

MoPub also sent an outside accounting firm to the corporate offices of Peabody in order to determine whether any of these unpaid charges by Peabody were justified under the terms of a contract, and whether the charges could be supported by proper accounting documents. As a result of this audit, MoPub estimated that $2,846,525 of the $4,888,145 liability on its books were not justified under the terms of a contract and, therefore, would never have to be paid to Peabody. In December, 1979, MoPub removed this $2,846,525 liability from its books and credited "Fuel Inventory" in the same amount.

The $4,888,145 charged to "Fuel Inventory" and credited to a liability account between April, 1978 and August, 1979 was eventually transferred from the coal inventory account to "Fuel Expense" as coal was burned, and was priced at the average price per ton in inventory. In December, 1979, the credit to "Fuel Inventory" of $2,846,525, and the corresponding charge to the liability account, reduced the liability on the books resulting from disputed coal charges from Peabody to $2,041,620. The net effect of these entries on the Company's books was a $2,041,620 increase in fuel expense on the income statement, and a corresponding liability in the same amount on the Company's balance sheet. As a result of the settlement, the Company has no obligation to pay the liability to Peabody. Therefore, the liability account was charged and "Extraordinary Income" credited in order to eliminate the liability on the books and to restate the Company's earnings for $2,041,620 of fuel expense charged against earnings in prior years.

The gain realized by the Company, of which the Staff is proposing amortization in this case, are the revenues which were collected through the Missouri Fuel Adjustment Clause during the period that the disputed charges from Peabody were recorded on the books of the Company. The amount of the disputed charges from Peabody that were recorded on the Company's books was $4,888,145. MoPub had a fuel adjustment clause in effect through October 1, 1979, which allowed the Company to recover its actual cost of coal-fired generation, and cost of coal- and gas-fired generation purchased from other utilities. The amount to be collected was determined on a monthly basis by comparing the actual cost of includable fuel costs with the cost included in the Company's base charge included in the permanent rates in effect. Any fluctuation above or below the base in the permanent rate would be collected or refunded to the ratepayer on billings made during the second month following the month in which the expense was actually incurred.

Coal fuel expense is determined on the books of an electric utility for a given month by multiplying the tons of coal burned during the month by the average cost per ton of coal in inventory on the books during the month. Because MoPub charged account 151--"Fuel Inventory," for amounts billed from Peabody which were not paid, from April, 1978 through August, 1979, these amounts were included in the Company's monthly calculation of fuel expense and, therefore, were included in the Company's fuel adjustment calculations during this period.

Staff recomputed the fuel adjustment clause calculations from April, 1978 through August, 1979 assuming that none of the $4,888,145 had ever been charged to fuel inventory. The result of comparing these adjusted fuel clause calculations with the actual calculations results in a difference of $1,211,734. Staff alleges that this amount represents revenues collected by MoPub, through the fuel adjustment clause, for fuel expense which was never incurred by the Company. In other words, it is alleged, MoPub collected from ratepayers $1,211,734 of the $4,888,145 of billed charges from Peabody, which the Company never paid to Peabody.

Staff asserts that the gain realized from the settlement of the Peabody lawsuit is an "extraordinary gain" since it results from an unusual, non-reoccurring event, i.e., an event not considered in the determination of rates under normal conditions. Staff asserts that such extraordinary items require specific ratemaking treatment when they occur. As an example, Staff cites the treatment given the extraordinary purchased power and maintenance expenses incurred by MoPub as a result of the Sibley 3 generator failure in 1980 (discussed hereinabove under section V. D., "Settlement of Westinghouse Lawsuit"). In that instance, MoPub was allowed to recover the extraordinary purchased power costs over a two-year period, and the extraordinary maintenance costs over the remaining life of the plant (18 years). The deferred debit which includes the unamortized balance at any point in time, was not allowed in rate base. This treatment, authorized by the Commission in Case No. ER-81-85, accomplished the sharing of the extraordinary costs in question by the ratepayer and the shareholder, by allowing the shareholder to recover every dollar of extraordinary purchased power and maintenance expense over the amortization period but not allowing a return to the shareholder on the unamortized balance, by not including it in rate base. This, in effect, caused the shareholder to share in the loss by suffering the loss of income that could be obtained if the funds were immediately available to him and could be invested for return. Staff asserts that its proposed amortization of the extraordinary gain from the Peabody settlement accomplishes three results which are consistent with the Commission's treatment of the extraordinary losses from the Sibley 3 outage in Case No. ER-81-85. These results are: (1) a conservative amortization period (two years in this case) which avoids having the entire amount of extraordinary gain being used to reduce the Company's revenues in one year; (2) the receipt by the ratepayer of the dollar benefit of the gain over a two year period; and (3) the fact that the ratepayer will not receive the benefit of a return on the unamortized balance in the deferred credit account, since Staff is not proposing that the deferred credit be used to reduce rate base in this case or in the future.

Company opposes Staff's proposed treatment of the Peabody settlement on the basis that Company has, in fact, "paid" Peabody for the coal by giving up something of value, i.e., its claim against Peabody for punitive damages, when it settled the lawsuit. Company asserts that while its claim for actual damages was worth not more than $200,000, its claim for punitive damages against Peabody was worth at least $2,000,000 and perhaps as much at $6,000,000. Had its claim for punitive damages not been "something of value," Company insists, Peabody would not have accepted MoPub's dismissal of MoPub's lawsuit against Peabody as consideration for Peabody's claim against MoPub for unpaid coal, which MoPub agreed was worth at least $2,041,000.

Company contends further that, even should the Commission determine that Company has not paid to Peabody for the coal an amount at least equal to the dollars which Company received through the Fuel Adjustment Clause, it would be impossible nonetheless to characterize those dollars as an "extraordinary gain" which should be passed on to ratepayers. For purposes of this argument, the Company contends that there is a difference between the term "extraordinary items" for accounting purposes, and the term "extraordinary items" for ratemaking purposes. According to the Company, "extraordinary items", for accounting purposes, are events and transactions that are distinguished by their unusual nature and by the infrequency of their occurrence. Company bases this definition on AICPA (American Institute of Certified Public Accountants) Professional Standards, Vol. 3, Accounting, as of June 1, 1981, pages 8039, et seq. On the other hand, Company asserts that "extraordinary items", for ratemaking purposes, refer to "large dollar items that are not infrequent and are not unusual," e.g. the purchased power and maintenance expenses incurred by the Company due to the 1980 Sibley 3 generator failure. Such generator failures, in Company's opinion, occur on a frequent basis in the operating experience of the utility industry. Company's definition of "extraordinary items" for ratemaking purposes has not been shown, however, to have its source in any AICPA standards, nor, for that matter, anywhere other than the Company's witness for purposes of this issue. According to the Company, sound ratemaking principles dictate that extraordinary accounting items should not be a factor in the determination of rates which will be in effect for future periods.

The Commission need not, and will not, attempt to evaluate the merits of Company's lawsuit against Peabody or Peabody's claim against the Company for unpaid coal invoices. The fact is that Company's ratepayers paid, through rates, $1,211,734 of coal costs through the Fuel Adjustment Clause between April, 1978 and August, 1979 which, as a result of the Peabody settlement, Company need not pay out. As a result of the settlement, the Company no longer has a liability for those dollars.

The Commission cannot accept Company's argument as to the definition and treatment of "extraordinary items" for ratemaking purposes. The elimination of the obligation of MoPub to pay out the $1,211,734 in question, as a result of the settlement of litigation, is clearly both an extraordinary event in the Company's overall operations and a source of extraordinary gain to the Company, since its liability for that amount has been released as a result. This settlement and its result are not reoccurring events considered in the determination of rates under normal conditions. Thus, they come within Staff's definition of "extraordinary items," which the Commission accepts. The Commission concludes that it would be unjust and unreasonable to permit the Company to retain the $1,211,734 in question, paid by ratepayers through rates to the Company.

The Commission agrees with the Staff that this extraordinary gain should be treated in a manner consistent with the Commission's treatment of extraordinary losses incurred by this Company as a result of the Sibley 3 outage in 1980. This determination is also consistent with the Commission's treatment of the extraordinary gain of the Company resulting from the settlement of its lawsuit against Westinghouse Corporation, discussed hereinabove (section V. D. of these findings of fact).

Therefore, the Commission concludes that the Company has received a net extraordinary gain of $1,211,734 as a result of the settlement of its lawsuit against Peabody Coal Company, which extraordinary gain should be amortized over two years. Accordingly, "Other Electric Income" should be increased by $605,867 for two years.

F. Tax Normalization

This issue concerns the proper ratemaking treatment of timing differences between entries on the books of the Company, and on tax returns of the Company. Tax-timing differences occur when items are recognized as expenses for income reporting on the books of the Company, in a different time period than when they are deductible on the tax return for determining taxable income. The tax-timing differences at issue in this case are: Capitalized interest, pensions and taxes capitalized, removal costs, unbilled revenues, book to guideline depreciation lives, and JEC trust deduction. This issue effects both the electric and water cases.

Staff proposes that all tax-timing differences at issue be "flowed through." Flow-through treatment allows the benefit of tax deductions in excess of book expenses to be passed along to ratepayers by excluding related income tax deferred expense from cost of service. Company, on the other hand, recommends that all tax-timing differences at issue be allowed full normalization. Normalization allows deferred income taxes to be collected currently from ratepayers as income tax expense, even though the tax dollars need not be paid currently to the Internal Revenue Service.

The Commission has frequently and consistently held in recent years that normalization treatment should be afforded only upon a showing that the utility requesting such normalization is experiencing significant cash flow problems. This "cash flow test" looks to interest coverage and internally generated funds used for construction as determinants of the need of a given company for normalization of tax-timing differences. In the instant case, MoPub has used internally generated funds to provide from 51% to 107% of its total construction expenditures in each year since

1975. In the most recent accounting period for which figures were available at hearing, the nine months ending September 30, 1981, internally generated funds represented 107% of MoPub's construction expenditures.

For the year ending November 30, 1981, MoPub's bond indenture interest coverage (including Series U bonds) was 2.51 times. Required coverage is two times.

Thus, the Commission concludes that the Company has not met its burden of proving that its cash flow requires normalization of tax-timing differences in this case. Nor has the Company persuaded the Commission that the "cash flow test" for determining tax normalization should be abandoned.

The tax-timing differences at issue in this case will be flowed through to the Company's ratepayers, as proposed by Staff.

In addition, the Commission concludes that written suggestions from regulated utilities should be invited on the issue of tax normalization in the recently established inquiry into certain matters of concern to the Commission (Case No. 00-82-277). This has been accomplished by an order in that proceeding.

G. Stipulation Concerning Accelerated Cost Recovery System

In the Hearing Memorandum in this case (Joint Exhibit No. 1), the parties stipulated and agreed that the Report and Order in the instant cases should contain the following specific provision:

> ORDERED: Company is authorized to use "the Accelerated Cost Recovery System" for calculating depreciation for income tax deduction purposes and is further authorized to use a normalization method of accounting, as defined and prescribed in the Economic Recovery Tax Act of 1981, and as defined and prescribed in any rulings or regulations which might be promulgated to further explain or define the provisions of that Act.

The Commission concludes that it is just and reasonable that the Company, pursuant to the Economic Recovery Tax Act of 1981, should be authorized to use "the Accelerated Cost Recovery System" as stipulated above. This Report and Order will contain the provision stipulated to by the parties.

VI. Rate Base

A. Jeffrey Energy Center (JEC) "Common Plant"

The treatment of certain "common plant" items located at Company's Jeffrey Energy Center, in calculating Company's jurisdictional electric rate base, was a contested issue set out in the Hearing Memorandum (Joint Exhibit No. 1) in this case. However, during the course of the hearing, the issue was settled by the parties and ceased to be a contested issue. The resolution of the issue was reflected in the reconciliation submitted on June 9, 1982 in this matter as a result of the true-up audit.

B. Fuel Inventories

Company and Staff are in disagreement as to the appropriate levels of coal inventories, maintained at the Company's Sibley and Jeffrey generating facilities, which should be included in the Company's rate base. Company and Staff are also in disagreement as to the appropriate levels of fuel oil inventories, maintained by the Company at its Jeffrey, Greenwood, Nevada and Kansas City International Airport (KCI) generating facilities, which should be included in the Company's rate base.

1. Coal Inventories

a. Sibley Generating Station

Company proposes that an average inventory level of 300,000 tons of coal is an appropriate fuel inventory for its Sibley Generating Station (Sibley). Staff, on the other hand, recommends that the coal inventory level for Sibley should be equal to a 90-day average burn, based on Sibley generation loading, plus the unburnable base volume of the Sibley coal pile of approximately 20,000 tons.

Company's proposed 300,000 ton level is approximately a 120-day supply. Coal is the fuel used by the Company to generate in excess of 90% of the kilowatt hours it produces, and is the lowest cost fuel that the Company burns. The Company has experienced interruptions of coal shipments because of strikes by the United Mine Workers (UMW), mine equipment breakdowns, railroad strikes, and difficulties in scheduling railroad locomotive power to coincide with car loadings. The Sibley plant furnishes approximately 75% of the Company's total annual generation. Company asserts that a coal inventory of less than 300,000 tons at Sibley would place the Company in a "continuously precarious fuel supply situation."

On the other hand, Staff's proposal is based upon the Company's receipts, and actual coal burn by month, since January, 1977. No need for an inventory in excess of ninety-days' supply was shown to have occurred in that time period. The Company did not run out of coal during the 1977-1978 UMW strike, which lasted 112 days, although it had only a sixty-six day supply on hand at the outset of the strike. Other UMW strikes in 1971, 1974 and 1981 have lasted 42 days, 24 days and 73 days, respectively. There is no evidence that railroad or other strikes have affected the Company's inventory levels. During the twelve (12) months ending December, 1981, Company maintained 271,589 tons of coal at Sibley.

Based upon the evidence herein, the Commission concludes that Staff's proposed 90-day coal inventory at the Sibley Generating Station, plus the unburnable base of 20,000 tons, is reasonable and adequate, and should be included in Company's rate base.

b. Jeffrey Energy Center

Company recommends that it be allowed to include some 130,390 tons of coal in rate base at its Jeffrey Energy Center (Jeffrey). This constitutes a 120-day supply. Staff proposes that a 90-day supply of coal is adequate at Jeffrey. Thus, the analysis of the appropriate coal inventory level set out above as to the Sibley Generating Station would apply also to Jeffrey.

However, Company has only an eight percent (8%) ownership interest in the Jeffrey Energy Center. Jeffrey is co-owned by Kansas Power & Light Company (KP&L), Kansas Gas & Electric Company (KG&E), and Central Telephone Utilities, none of which are under the jurisdiction of this Commission. KP&L is the operating company of Jeffrey, and determines the fuel inventory levels which are to be maintained at Jeffrey. The three non-Missouri owners of Jeffrey are authorized by the Kansas

Corporation Commission to include a 120-day fuel inventory at Jeffrey in their rate bases. As a minority, eight percent (8%) owner of Jeffrey, Missouri Public Service Company cannot dictate the fuel inventory levels to be maintained there.

The Commission finds that the Company has made a prima facie showing that it is bound by the fuel inventory determination of the operating company of the Jeffrey Energy Center, KP&L. Staff has not shown that the Company has the legal capacity to exercise independent judgment as to those fuel inventories at Jeffrey. Since the matter is beyond the control of the Company, the Commission determines that it would be unjust and unreasonable to disallow from Company's rate base a portion of the fuel inventory levels at Jeffrey which it is required by KP&L to maintain. Therefore, a 120-day coal inventory at the Jeffrey Energy Center will be allowed in Company's rate base in this case.

The Commission notes that the Company, in its initial brief and in its reply brief in this case, accuses the Commission of unlawfully promulgating a "rule" concerning coal inventories. This argument of the Company is advanced in opposition to the Staff's recommendation of coal inventories at Sibley and Jeffrey equivalent to a 90-day annualized burn. The Commission finds the argument to be both without merit, and offensive. While not bound by the legal principles of res judicata or stare decisis, this Commission certainly has the authority to establish and follow reasonable, consistent principles and guidelines in approaching issues which are presented to the Commission for decision with some frequency. This Commission has consistently found 90-day annualized coal inventories to be reasonable for many electric utilities within the Commission's jurisdiction. That general policy should prove to be of assistance to regulated electric utilities in their planning, and in their preparation of rate cases. However, it is a policy, and not a rule of general and binding applicability to all electric utilities under the Commission's jurisdiction. It is, instead, a standard which is both reasonable and clearly based upon the evidence of record in each case before this Commission in which it has been applied. It is also a standard which the Commission reserves the right to review, and does review, upon the unique facts of each contested rate case in which coal inventories are an issue. The Commission takes vigorous exception to the Company's characterization.

2. Fuel Oil Inventories

a. Jeffrey Energy Center

Company proposes to include in rate base a fuel oil inventory level equivalent to the 13-month average of its actual oil inventory at Jeffrey Energy Center. Staff proposes that the appropriate oil inventory for Jeffrey Energy Center should equal a 90-day burn based upon Staff's annualized burn in this case.

The oil inventory maintained at Jeffrey is determined by the operating Company of Jeffrey, Kansas Power & Light. As discussed above, Missouri Public Service Company, as a minority eight percent (8%) owner of Jeffrey, has no direct control over the level of oil inventory maintained at Jeffrey. Therefore, the Commission concludes that the Company should be allowed to include in its rate base the oil inventory level required by KP&L, for the reasons set forth above as to the Jeffrey coal inventory.

b. KCI, Nevada and Greenwood Generating Facilities

It is the Company's position that fuel oil inventories at its KCI, Nevada and Greenwood facilities should be maintained at approximately 80% of the tank capacity at each of those locations, in order to ensure system reliability. Staff, on the other hand, believes that lesser levels of oil will be adequate to serve the Company's customers during peak periods and emergencies. Staff proposes to include in Company's rate base, oil inventories at KCI, Nevada and Greenwood equal to the average of the actual burn at each of those facilities in 1980 and 1981 and the annualized burn during the test-year, then adding to that average the annualized test-year burn.

Company's KCI facility is located near the Kansas City International Airport complex. Company has two gas-turbine units at its KCI facility. Company believes that it requires an oil inventory of approximately 80% of its tank capacity at KCI in order to ensure that the KCI facility could provide electricity to the Platte County area, including the Trans World Airlines-KCI Airport complex, in case of an emergency. However, KCI's primary fuel is natural gas, and operation of the facility is generally more expensive than purchased power. Thus, for KCI to require the use of its oil inventories, one or both power lines to KCI would have to be out of service, and natural gas and purchased power would have to be unavailable.

Company's Nevada facility has a 19,000 KW gas turbine. Company's proposed inventory level of some 418,262 gallons of oil for the Nevada gas turbine would allow the plant to operate at full load for approximately eight to nine days. Staff's recommended inventory level of 43,440 gallons of oil inventory (14,089 recoverable gallons), would allow the plant to operate at full load for seven hours. Company has, in the past, experienced the loss of the transmission stepdown-transformer at Nevada, as well as the loss of the 161-KV transmission line which serves the area. The transformer was out of service for more than six months, although the Company was able to continue service from that unit after seven days by utilizing a spare transformer. Company asserts, without explanation, that a spare transformer is not always available. Staff, however, has considered the abnormal burn at Nevada due to the transformer failure in its oil inventory proposal in this case. If necessary, it is possible to truck additional oil into the Nevada facility. The Company also has interconnections with the MoKan Power Pool to provide emergency purchased power when necessary. Company has not shown in this case that its Nevada operations are so unique or distinct from the rest of its system as to require an extraordinary level of oil inventory for peak load and emergency requirements. The record does reflect, and the Commission finds, that the Company's proposed oil inventory at Nevada far exceeds its actual historic need, and its reasonably anticipated need, for such inventory.

At Greenwood, Company has four gas turbine units, each rated at 48,000 KW. These units are commonly referred to as the Greenwood Energy Center. Company recommends a gross inventory level of oil of 4,204,163 gallons at Greenwood. Staff, on the other hand, recommends a gross inventory level of 3,885,706 gallons of oil at Greenwood. Company asserts that its fuel oil inventory level at Greenwood is critical, since the units represent approximately 21% of the Company's generating capacity. However, only about seven-tenths of one percent (.7%) of Staff's annualized megawatt hour generation in this case is supplied by the Greenwood units. The largest burn at Greenwood since 1977 in a 30-day period was the 30-day period ending August 7, 1980, of approximately 1,494,988 gallons of oil. Staff's recommended inventory level of 3,885,706 gallons far exceeds that maximum actual burn.

A major outage at Sibley Unit No. 3 occurred from August of 1980 through January of 1981. Company's loss of generating capacity due to that outage was primarily covered by purchased power. Sibley 3 represents forty-two percent (42%) of the Company's generating capacity. No blackouts resulted from the Sibley 3 outage. During the entire Sibley 3 outage, Company burned 788,450 gallons of oil. On average, some 93 to 95 percent of the kilowatt hours generated by the Company are produced by base-load coal, and some one or two percent by oil. During Company's peak month of 1980, which was the month of July, Company burned 1,174,141 gallons of oil. Staff's total recommended inventory level in this case is 3,947,311 gallons.

Company has not shown that its proposed fuel inventory levels are necessary to avoid the payment of penalties or equalization charges to the MoKan Power Pool.

Upon the evidence herein, the Commission concludes that the recommended oil inventory levels of the Staff in this case are reasonable and adequate, and are the oil inventory levels which should be included in the Company's rate base.

C. Cash Working Capital

Cash working capital is a rate base item which reflects the amount of cash necessary for a utility to pay the day-to-day expenses incurred in providing service to its ratepayers. The ratepayer and the shareholder are the sources of cash working capital. The ratepayer supplies cash working capital when he pays for service before the company must pay for expenses incurred to provide that service. When a company pays for an expense before the cash is provided by the ratepayer, however, that cash must be provided by the investor or shareholder. This cash represents a portion of the investor's total investment in the company, and its inclusion in the Company's rate base provides the shareholder with an opportunity to earn a return on that portion of his investment.

The Commission has accepted the methodology of lead-lag studies to determine the amount of funds that are necessary on a day-to-day basis in order to provide service to ratepayers, and to determine who supplies those funds. Lead-lag studies are performed to determine both revenue lags and expense lags. A revenue lag describes the amount of time between the provision of service by the company and the receipt of the payment for that service by the ratepayers. An expense lag describes the amount of time between the receipt of goods or services by the company, and the payment by the company for those goods and services, which expense was incurred by the company in order to provide service to the ratepayer. A lead-lag study which results in a negative cash working capital requirement indicates that, in the aggregate, the ratepayer provides cash working capital to the company. A lead-lag study which results in a positive cash working capital requirement indicates that, in the aggregate, the investor or shareholder provides cash working capital to the company. Thus, a company's rate base would be reduced by a negative cash working capital requirement, and increased by a positive cash working capital requirement.

In the instant case, both Staff and Company performed lead-lag studies to compute the Company's cash working capital requirement. The difference between the proposed cash working capital requirements is represented by five separate areas of disagreement, discussed individually below.

One key difference between the Company and Staff on this issue concerns the appropriate definition of an "expense lag." Staff uses the definition which has been generally accepted by this Commission, which is the amount of time between the receipt of goods or services and the payment of these expenses incurred to provide service to the ratepayers. Company, however, uses the term "expense lead days" rather than the term "expense lag," and defines "expense lead days" as the period of time that elapses between the date an item is recognized as an expense of the Company, and the date the Company pays for such goods and services.

1. Expense Lags for Coal and Freight Expenses for Sibley Generating Station and Jeffrey Energy Center

Based on its lead-lag study, Staff assigns an expense lag of 35.35 days for coal and freight expenses related to the Company's Sibley Generating Station. Staff also assigns an expense lag of 20.04 days for freight expense, and 22.28 days for coal expense, related to the Company's Jeffrey Energy Center. The Staff asserts that these expense lags represent the average time lag between the receipt of coal at these generating facilities, and payment for such coal and related freight expenses. Staff sampled all vouchers for coal purchased at Sibley and Jeffrey in 1980 to calculate these expense lags. Company directly pays for coal and freight at Sibley, but pays Kansas Power & Light Company (KP&L) for coal and freight as to Jeffrey. KP&L is the operating company of Jeffrey. Three months' data was examined by Staff to measure the period from the delivery of coal (freight service rendered) to the date Company paid KP&L for such freight service. The coal and freight expense lags at Sibley are both 35.35 days, since coal and freight charges are paid to the coal companies simultaneously and receipt of the good (coal) and the service (freight service) are simultaneous.

Company's lead-lag analysis provides for zero expense lead days for coal and freight expense related to Sibley and Jeffrey. Company's rationale is that it purchases, pays for, and places coal into inventory (i.e., classifies it as an asset), prior to that coal's actually being burned and expensed at the time it is actually used for the benefit of the ratepayer. Therefore, under the Company's rationale, coal has already been paid for by the Company by the time it is expensed (i.e., burned), resulting in a zero expense lag. Between the time the coal has been received by the Company and the time it is expensed, according to the Company, it is carried on the Company's books as an asset (i.e., coal inventory) and not as an expense. Company asserts that to consider this period of time in the computation of an expense lag in the cash working capital allowance confuses this issue with that of fuel inventory, an asset account, and an item which is recognized separately in rate base.

The Commission rejects Company's position. In Case No. ER-80-118, Re: Missouri Public Service Company, at page 12 of its Report and Order, the Commission stated the following:

> The Company claims no lag in fuel expense on the ground that it had been paid prior to the time the expense is booked. The Company's contention appears to be erroneous in that a lag study is to determine the length of time after products are delivered before the payment must actually be made. It has no relation to the time that the fuel is taken out of inventory and booked as an expense.

In the same Report and Order (Case No. ER-80-118), this Company's proposal of a negative lag for transportation expenses was rejected in the following language:

> The Company has calculated a negative lag for transportation expenses as a result of the expense being booked prior to its payment and even prior to the receipt of the service. Such calculations would appear to be erroneously included in an expense lag study since the time of the booking of an expense may have little relationship to the actual time of the cash outlay and the payment for the services involved.

In Case No. ER-81-42, Re: Kansas City Power & Light Company (June 17, 1981), Company had proposed that a single revenue lag be applied to "total operating revenues," including all of the factors included in a customer's bill (and not just the line-items to which an expense lag was applied or otherwise included in Company's lead-lag study). KCPL's proposal was based upon the principle that its cost of service should be determined on an accrual basis. In rejecting KCPL's proposal, the Commission stated the following:

> The accrual basis of cost of service accounting in general is simply not relevant to the calculation of a company's cash working capital requirements, as consistently defined and applied by this Commission. The issue here is not when test year revenues accrue; but what the cash needs of the Company are for the actual payment of cash-item expenses on a day-to-day basis, and the identity of the supplier of that cash. Lead-lag studies are not performed on an accrual basis, then. By definition, cash working capital requirements must be determined on a cash basis.

Likewise, the issue here is not when coal and freight expenses are booked by the Company; but what the cash needs of the Company are for the actual payment of cash-item expenses on a day-to-day basis, and the identity of the supplier of that cash. The Company incurs a known and measurable obligation for goods and services used in providing service to ratepayers at the time such goods and services are received, and those goods and services are available to the Company at the time they are received. The time of the booking of an item to expense does not alter the fact that there is a time lag between the receipt of goods and services and the related payment for those goods and services (an expense lag) which has an affect on cash flow. Thus, the assignment of a zero-day expense lag to coal and freight expenses as to Sibley and Jeffrey would ignore the purpose of the cash working capital allowance, as defined hereinabove and in the quote from the Kansas City Power & Light Company case in 1981 (ER-81-42). For purposes of calculating the Company's cash working capital requirement, the Staff's definition of expense lag must be applied. Under that definition, it is the timing difference between receipt of the coal and of freight service, and the date when the Company pays for such coal and freight service, that is determinative, and not the time at which such coal and freight items are expensed on the Company's books.

The Commission concludes that the expense lags calculated and proposed by the Staff as to coal and freight expense related to Sibley and Jeffrey shall be used in the calculation of the Company's cash working capital requirement in this case.

2. <u>Propane Expense Lag</u>

Staff proposes an expense lag for propane expense, which was calculated by examining all payments for propane in 1980, calculating the lag for each receipt of propane and payment therefor, and then weighting each lag by the amount of the payment. Company proposes to apply a zero-day expense lead for propane, under the same rationale advanced as to coal and freight expenses for Sibley and Jeffrey, discussed above.

For the reasons stated hereinabove as to coal and freight expenses related to Sibley and Jeffrey, the Commission rejects the Company's proposal that a zero-day expense lead be assigned to propane expense. Rather, the expense lag for propane expense which was calculated and proposed by the Staff in this case shall be applied in determining the Company's cash working capital requirement.

3. Expense Lag for Charges to Expense from Clearing Accounts, and Materials and Supplies

Company proposes a zero-day expense lag for charges to expense from clearing accounts and materials and supplies, under the same reasoning advanced by Company as to coal, freight and propane expense, discussed hereinabove, i.e., that the payment lag occurs while these items are an asset of the Company, which is well in advance of the time when these items are charged to operating and maintenance expense.

However, Staff did not stratify this item in its cash working capital calculation in this case. Due to an oversight in reviewing a previous cash working capital study of this Company, Staff did not analyze certain lags separately, including those currently under discussion, and those pertaining to lease expense discussed hereinafter. By certain amended prepared testimony presented in this case, Staff attempted to rectify its oversight by proposing that an expense lag of 34.56 days be applied to the annualized test-year expense for charges from clearing accounts and materials and supplies. That figure actually represents the expense lag for maintenance expenses paid on cash vouchers, and is considered by Staff to be a conservative estimate of the expense lag for charges to expense from clearing accounts and materials and supplies. Staff admits that the lag associated with maintenance paid on cash vouchers does not bear any direct or actual relationship to the lag associated with materials and supplies, but asserts that said lag would be a more reasonable representation of the materials and supplies expense lag than would zero. Staff admits that the actual expense lag in question could be more or less than 34.56 days.

In an effort to correct its oversight in omitting this item from specific consideration in its prefiled cash working capital calculation in this case, Staff recommended that it be allowed to further investigate this item and update its expense lag calculation as part of the true-up proceeding in this case.

As to the coal, freight and propane expense lags discussed earlier in this Report and Order, the Company proposed a certain treatment of those items for purposes of calculating its cash working capital requirement, and submitted evidence as to the propriety of its proposed treatment. Staff, on the other hand, proceeded to present evidence proposing a different treatment of those items in calculating the Company's cash working capital requirement, which evidence persuaded the Commission that Staff's treatment, rather than the Company's, should be adopted. As to clearing accounts and materials and supplies, however, the Company has met its prima facie burden of proof on the issue, and the Staff has failed to put forward competent and substantial evidence which persuades the Commission that Staff's treatment, rather than Company's, should be adopted. Therefore, a zero-day expense lag will be assigned to charges to expense from clearing accounts and materials and supplies, in the calculation of Company's cash working capital requirement in this case.

The Commission notes that Staff's proposed remedy of further investigating this expense lag and presenting updated testimony as part of the true-up proceeding in this case, would not be an appropriate use of the true-up proceeding. Rather than merely presenting updated figures to be inserted into testimony presented at the evidentiary hearing in the case, and subjected at such hearing to full cross examination by all parties to the proceeding, Staff's revised proposed expense lag as presented at the true-up proceeding would never have been subjected to cross-examination by the other parties. Staff's recommendation as to providing a revised expense lag figure for this item as part of a true-up would, therefore, be unacceptable.

4. Revenue and Expense Lags for Lease Expense

Company's lead-lag study resulted in a determination that the revenue lag for lease expense is 39.91 days, and that the expense lag for lease expense is 11.45 days. The latter figure is based upon the fact that Company has generally made the first lease payment 11.45 days after it was included in rates authorized by this Commission. This calculation was determined by examining the initial lease payment for all current turbine and coal car leases and comparing those payment dates to the earliest date that the lease payments were allowed in electric rates pursuant to this Commission's authorization. Thus, while Company has advocated the calculation of expense lead days based on the time of recognition of an expense on the books of the Company, as to lease expense the Company advocates a determination of expense lead days based upon the time of recognition of the expense to the ratepayer.

Staff, on the other hand, proposes a zero-day revenue lag and a zero-day expense lag as to lease expense. As in the case of clearing accounts, materials and supplies, discussed hereinabove, Staff failed to stratify lease expense in its cash working capital calculation in this case. After this oversight was discovered, Staff separated out the annualized test-year lease expense dollars as a line item, but assigned zero revenue and expense lags. Again, Staff recommended that it be allowed to further analyze this item and insert the appropriate lags in the course of the true-up proceeding in this case.

The Commission concludes that the Company has made a prima facie showing of the reasonableness of its proposed revenue lag and expense lead days as applied to lease expense, and that the Staff has failed to persuade the Commission that a different calculation of revenue and expense lags for lease expense is more reasonable. The Commission finds no competent and substantial evidence in support of the Staff's proposal for zero day revenue and expense lags as to this item. Nor would Staff's recommendation as to the presentation of further evidence on this issue at the true-up proceeding constitute an appropriate use of the true-up proceeding, for the reasons stated hereinabove as to the issue of the expense lag for clearing accounts, materials and supplies.

5. Expense Lag for Interest Expense Offset

Staff proposes that an expense lag of 91.25 days be assigned to the item of interest expense in Company's cash working capital requirement. Staff views interest as being precollected from the ratepayer for purposes of passing it on to the bondholder. Thus, 91.25 days represents the period of time calculated by Staff in its lead-lag study from the date of receipt of the funds to pay interest, and the date of payment of interest on Company's debt.

Company, on the other hand, proposes an expense lag of 11.96 days for interest expense. Company performed a study of outstanding bond issues and determined that Company made the first interest payment on those bond issues, on the average, 11.96 days before the effective date of a Commission order authorizing new rates which included the cost of the new debt issue.

Staff's proposed expense lag constitutes a net expense lag (its proposed expense lag as to interest expense exceeds its proposed revenue lag as to interest expense), so that interest expense on long-term debt would become an offset to Company's cash working capital requirement in this case. The Commission has previously held that the use of accrued interest on long-term debt as an offset to the cash working capital requirement is proper. Re: Missouri Public Service Company, Case Nos. GR-80-117 and ER-80-118; Re: Kansas City Power & Light Company, Case No. ER-81-42. In so holding, the Commission has held that the net expense lag associated with the payment of interest expense is an appropriate offset because the funds are ratepayer supplied, the obligation to pay interest on debt is known and certain as to quantity and time, and the amount is precollected from the ratepayer for the purpose of passing it on to the bondholders.

Company's proposal in this case is similar to the position this Company advanced in its last contested rate case, Case No. ER-80-118, and seems to be based upon concern for contemplated future issuances of long-term debt. Should the Company issue long-term debt after the rates are set in the instant case, Company believes there would be no provision for recovery of the interest on the new issuance and, to the extent that any interest payment became due prior to the establishment of new and higher rates, the Company would have prepaid the interest expense.

As stated by the Commission in its Report and Order in Case No. ER-80-118, the Company's position appears to be in conflict with the concept of a test-year. As stated earlier in this Report and Order, the purpose of using a test-year is to create or construct a reasonably expected level of earnings, expenses and investment during the future period during which the rates, to be determined herein, will be in effect. The parties to this case agreed to utilize, as a test-year, the twelve-month period ending September 30, 1981, as adjusted for known and measurable changes through April 30, 1982. The parties also agreed to utilize certain facts and account balances as of April 30, 1982, based on a "true-up" audit. One of the "true-up" items agreed to was the Company's capital structure at April 30, 1982, updated for financings occurring between April 30 and the true-up audit. (See section VII. A., below). Thus, interest expense on long-term debt is accounted for in the test-year in this case on a "trued-up" basis. An element of funds to be utilized for payment of interest expense is included in the rate of return component in every dollar of service rates paid to the Company by the ratepayers. The Commission concludes that the Company's proposal on interest expense lag must be rejected, and that Staff's interest expense lag will be used in calculating Company's cash working capital requirement in this case.

D. <u>Original Cost Rate Base</u>

On the basis of the competent and substantial evidence in this case, and after making appropriate adjustments in accordance with the determination of contested rate base issues above, the Commission finds that the Company's Missouri jurisdictional net original cost rate base for the purpose of this case is $259,877,287 for electric operations, $2,453,066 for Clinton water operations, and $271,963 for Osceola water operations.

## VII. Cost of Money/Rate of Return, and Attrition Allowance

### A. Capital Structure

All parties agreed to use Company's actual capital structure existing at April 30, 1982, as updated for financings occurring between April 30, 1982 and the true-up audit (the results of which were filed in this case on June 9, 1982). That capital structure is set out below:

| | Amount | Ratio | Embedded Cost |
|---|---|---|---|
| Long-Term debt | $142,662,483 | .5115 | .0773 |
| Preferred & Preference Stock | 43,820,000 | .1571 | .1007 |
| Common Equity | 92,416,077 | .3314 | -- |

For purposes of the hearing in this case, all parties agreed to use an estimated capital structure, set forth below:

| | Amount | Ratio | Embedded Cost |
|---|---|---|---|
| Long-Term debt | $152,662,483 | .533 | .0833 |
| Preferred & Preference Stock | 43,140,000 | .150 | .0998 |
| Common Equity | 91,000,000 | .317 | -- |

### B. Return on Equity

Once a capital structure and embedded cost of debt and preferred stock are determined, the ultimate finding as to a fair rate of return next requires the determination of the appropriate return on equity. Company contends that the appropriate return on equity to be determined in this proceeding, for both electric and water operations, should be 17.5%. Staff contends that the appropriate return on equity for both the electric and water operations lies within a range of 14.9% to

15.4%. Company further proposes that the Commission authorize an "attrition allowance" of 10% of the return on equity, which proposal is opposed by the Staff, and is discussed separately below under section VII. C., "Attrition Allowance."

Staff and Company both performed discounted cash flow (DCF) analyses. A DCF analysis, which the Commission has consistently found to be an appropriate methodology for determining return on equity, is based upon the assumption that current investors value a share of stock by projecting the future flow of dividends and future value of the share of stock, discounting those values to the present time. The basic formula for a DCF analysis is expressed as an equation:

$$k = \frac{d}{p} + g.$$

In the equation, "k" equals the required rate of return on the common equity, "d" equals indicated dividends per share, "p" equals the price of the stock, and "g" equals an expected growth factor.

From an investor's point of view, his cash flows consist of the dividends he receives while he holds the stock, plus his capital gain or loss, i.e., his selling price less his purchase price. The DCF formula considers both dividends and capital gains. Therefore, DCF attempts to determine the cash flows that an investor can reasonably expect to receive.

The DCF formula set out above is only applicable to the cost of common equity obtained from internally obtained funds. Common equity obtained from public offerings of additional common shares is more costly, due to flotation costs associated with selling the new shares. For externally obtained (market procured) common equity, the DCF formula must be adjusted to reflect this additional cost as follows:

$$k = \frac{d}{p\ (1-f)} + g$$

In this form of the equation, "f" equals flotation costs as a percent of book value.

In determining its proposed appropriate level of return on equity for the Company, Company performed two discounted cash flow (DCF) analyses, and a comparative earnings analysis. Company's first DCF analysis used data developed from an analysis of nineteen electric utility companies which MoPub considers comparable to itself. Company's analysis led to its use of a yield (represented by the $\frac{d}{p}$ portion of the DCF formula) of 13.5%, and a growth rate of 3.75%, resulting in a required rate of return on equity of 17.25%. This cost of equity, consistent with the DCF formula, would produce a market price per share equal to book value. If proceeds from the sale of new common equity are to yield book value to the Company, however, a market price of more than book value must be achieved and maintained, because of flotation costs (as stated above), and also, according to the Company, because of "pre-offering pressure." Flotation expense is the cost of the issuance, related to legal and accounting opinions, the cost of sales efforts, printing, etc., which are deducted from the proceeds of the sale. "Pre-offering pressure" is a supply-demand phenomenon, in Company's opinion, which tends to cause individual securities to sell down in anticipation of a new offering. To adjust for these factors, Company modified its DCF equation to the following:

$$k = \frac{(d)\,(1+g)}{(1-f)} + g$$

In this form of the equation, "d" equals calculated yield, "g" equals growth, and "f" equals the cost of issuance and "pre-offering" pressure. Company asserts that "under current market conditions", the minimum adjustment for pre-offering pressure and flotation is 10% (3.5 to 5% flotation costs, and 5% to 7.5% pre-offering pressure). Adjusting its dividend yield component by the 10% flotation and pre-offering factors results in an indicated return under Company's first DCF analysis of 18.75%.

Company's second DCF analysis employed data specifically related to yields and dividend growth of MoPub. In this analysis, Company determined a cash yield per share of 10.10%, and a stock yield per share of 4.04%. (MoPub pays a stock dividend on a semi-annual basis in the amount of 2% which, compounded, Company determines to be an annual stock dividend of 4.04% of the holdings). Company also used a 2.5% growth rate, which it described as "extremely conservative," and a one percent flotation adjustment, resulting in an indicated return on common equity of 17.64%.

Finally, Company performed a "comparable earnings" analysis, based upon an examination of sample companies for the period 1972 through 1980. Company looked at returns on equity, market-to-book ratios, and earnings-price ratios for its sample companies, and concluded that its comparative earnings analysis, when adjusted for pressure and flotation expense, produces the same range of required returns on equity as its DCF analyses. Company's witness Dunn, who prepared and presented the DCF analyses and comparative earnings analysis on behalf of the Company, concluded that the Company's financial risk is higher than the sample group of utilities used in the above analyses because Company has a lower equity ratio.

The Staff also used a DCF analysis, which produced results widely divergent from those of the Company's analyses. Staff considered current and recent historic market yields of MoPub's common stock. During the period 1974 through 1981, market yields of MoPub's common stock ranged from 5.7 to 9.8%, and averaged higher than yields prior to 1974. The average market yield in 1981 was higher than any other year (in the data considered, which dated back to 1965), but lower yields were experienced later in 1981 than in early 1981. Staff used indicated dividends, end-of-month market prices and resulting market yields for the common stock of MoPub during the period January, 1979 through January, 1982. That data led Staff to conclude that the market price of MoPub's common stock has displayed the ability not to be too adversely affected by the volatile market conditions that have been experienced over the past two years, and Staff used the range and average of market yields since November 30, 1981 in the yield portion of its DCF calculations. Those yields ranged from 8.7% to 9.9%, and averaged 9.3%.

To determine a growth rate that investors could reasonably expect to be experienced by MoPub, Staff utilized the earnings and dividend per share data for MoPub since 1965. Earnings per share have fluctuated considerably since 1970. While dividends per share have grown at a more even pace, cash dividends have increased at an uneven rate (8¢ from 1965 to 1966, 4¢ in 1972 over 1971, and 16¢ in 1976 over 1975). MoPub's stock dividend policy was also considered by the Staff, which concluded that, without an increase in the cash dividend and assuming the maintenance of the present stock dividend policy, an investor could expect the dividends he received to grow at a rate slightly in excess of 4%, as a minimum. Due to these uncertainties, Staff concluded that the growth rate for use in its DCF formula should be a range of growth rates from 4.1% to 5.3%. The high estimate of 5.3% is based upon an average of four long-term growth rates in Staff's study.

Staff also determined that a 5.5% flotation cost adjustment should be used in its DCF analysis to result in net proceeds from the sale of common stock of at least book value. Using these figures, Staff calculated a range of required returns on common equity for the Company of 14.1% to 15.8%, and concluded that its best estimate would fall in the range of 14.7% to 15.1%.

Staff also performed a regression analysis to determine those characteristics of electric utilities that investors consider most significant in arriving at the values they place on the common stocks of electric utilities. Twenty-eight variables were applied to 78 companies for the years 1973 through 1980. Neither MoPub nor Rochester Gas and Electric Company were included in the sample 78 companies, because they are the only major electric utilities that declare a stock dividend. For that reason, their dividend payout ratios are materially lower than the industry average and, therefore, are not comparable to the other companies in that respect. Staff's regression analysis resulted in a range of 14.93% to 15.95% of returns on common equity, depending upon the payout ratio used. The payout ratios ranged from 77% to 80% which, in Staff's estimation, represented the surrogate for MoPub's payout ratio if it did not have a stock dividend policy.

Averaging the lows and highs of the ranges produced by its DCF analysis and its regression analysis, results in a range of 14.9% to 15.4%, which Staff recommends as the required return on common equity for MoPub.

The Commission concludes that the range of returns proposed by Staff is fair and reasonable, and should be relied upon in this case. The Commission determines, on the evidence herein, that the dividend yields and growth rates utilized by Company in its DCF analysis are overstated. Further, Company has not proven the existence of, nor persuaded the Commission as to the accuracy of its quantification of, "pre-offering pressure" as used in its DCF analyses. Nor has the Company's testimony persuaded the Commission that MoPub is a "higher risk" than other electric or water utilities similarly situated.

Having considered the totality of the competent and substantial evidence before it in this case, the Commission finds that the appropriate and necessary return on common equity to be allowed Company is 14.9%, as to both electric and water operations. Applying this figure to the capital structure agreed to by the true-up audit in this case results in an overall rate of return of 10.47%, as reflected in the chart below, subject to the adjustment on return on water rate base as discussed separately below under section IX. D., "Adjustment to Return on Water Rate Base."

| | Amount | Ratio | Embedded Cost | Weighted Cost |
|---|---|---|---|---|
| Long-Term debt | $142,662,483 | .5115 | .0773 | 3.95% |
| Preferred & Preference Stock | 43,820,000 | .1571 | .1007 | 1.58% |
| Common Equity | 92,416,077 | .3314 | .1490 | 4.94% |
| | $278,898,560 | 1.0000 | | 10.47% |

C. Attrition Allowance

Company proposes that the Commission authorize an attrition allowance of 10% of the return on equity. Staff and Public Counsel oppose such an allowance.

In support of its proposed "attrition allowance," Company asserts that the revenue requirement determined in this case will be obsolete during the period in which the rates are in effect, in light of the dynamics of today's economy, and most likely will not produce the cost of capital. Company cites a high inflation level, a high federal deficit and the commitment of the Federal Reserve respecting money supply as indications of a continuation of erratic monetary and financial conditions. Company asserts that the current economic environment is worse than that of the recent past, while the rate-setting procedural process is the same, making the possibility of earning the established rate of return "very slight." Therefore, Company proposes its "attrition allowance" in the form of an accounting adjustment in an amount sufficient to offset what can be estimated from past experience as foreseeable increases in expense and shortfalls in revenue. Company proposes that this "attrition allowance" should be measured as a percent of the weighted cost of common equity.

Company presented evidence of the relationship between the rate of return authorized in each of its five rate cases between 1975 and 1980, and the rate of return actually earned during the twelve (12) months following the Commission's decision in each of those five rate cases. The cases studied were Case Nos. 18180, 18502, ER-78-29, ER-79-60, and ER-80-118. The average return authorized in those cases was 13.51%, and the average return earned was 11.62%, or 86% of the authorized amount. Company asserts that this analysis indicates an experienced attrition of 14%.

Company also relies heavily on what it terms "the continuing level of inflation." Company cites a projection by the Council on Wage and Price Stability, at the time of the filing of Company's testimony in this case (October 26, 1981), that the embedded rate of inflation is 10%. In turn, Company asserts that an attrition allowance must be at least 10% in order simply to accomodate inflation. Company characterizes its 10% "attrition allowance" as "extremely conservative."

Staff and Public Counsel oppose Company's proposed attrition allowance. Staff's witness testified that he did not "really have too much of a problem with an attrition allowance," but that the use of historic data to compute an attrition allowance was, in his opinion, tantamount to retroactive ratemaking. Staff's witness asserted that an attrition allowance which could be "conceived and computed on some other basis" would be more acceptable to him. However, Staff did not propose any alternative form of attrition allowance in this case.

Public Counsel generally opposes attrition allowances on the grounds that they require speculation concerning the future rate of inflation and the effect of inflation on the Company. In its brief, Public Counsel asserts that there is no evidence in the record in this case to provide a basis for a determination by the Commission of either the future rate of inflation, or the effect of past or future inflation on the Company. The Company's evidence is simply that there has been inflation in the past, and that the Company has not earned its authorized returns. As Public Counsel points out, there is no evidence in the record to establish a causal relationship between these two events or to show that, if the Company has in fact recorded an earnings shortfall, it has been due entirely to inflation and not to inefficient management or the recording for financial reporting purposes of items of expense disallowed by this Commission for ratemaking purposes. Public Counsel further points to the evidence in this case that the Company's average return on equity as of November 30, 1981 (excluding extraordinary gain) was 15.33%, substantially in excess of the 13.75% authorized return established in the Company's most recent tried rate case (ER-80-118), and above the midpoint of the range of returns on equity advocated in the instant case by the Staff. Public Counsel asserts that, in the absence of evidence which quantifies the effects of forces beyond the control of the Company on its earnings, it is "singularly inappropriate" to grant an attrition allowance to the Company.

The Commission has seen various attempts by regulated utilities within its jurisdiction to quantify "attrition" by a broad-brush approach such as proposed by the Company in this case. The Commission concludes that the Company has failed to meet its burden of proving that the asserted erosion of the Company's rate of return by "attrition" is the result of forces beyond the control of the Company, or that an across-the-board 10% increase in Company's authorized return on equity is an accurate measure of such "attrition." The Company's proposed attrition allowance in this case must be rejected.

The Commission cannot conclude upon the record herein that "attrition" does not exist, and the Staff has indicated that it accepts the concept of attrition. Staff has indicated in other recent cases before the Commission that it is studying the concept of attrition, and attempting to formulate a method of quantifying same. The Commission will expect, therefore, to see a specific proposal from Staff in this Company's next rate proceeding, on the issue of attrition. The Commission has accepted in some recent cases, methods of forecasting fuel expenses by electric utilities when such methods have been proven to have a high level of accuracy. See, for example, Re: Kansas City Power & Light Company, P.S.C. Case No. ER-81-42 (June 17, 1981). However, The Commission cannot accept an across-the-board 10% increase in allowable return on equity as an attrition allowance, based upon an inflation rate at a given point in time which may not be reasonably representative of either historic or reasonably expected future inflation rates, given the uncertainties of the current economy.

Staff has also argued in this case that Company's proposed attrition allowance must be rejected because it was not included in the Company's tariffs. The Commission rejects this argument. The proposed attrition allowance is simply one of numerous issues concerning the components of the Company's cost of service, the resolution of which result in the determination of the Company's revenue requirement which the Company should then be authorized to collect from ratepayers through its rates, subject to the limitation, of course, that the Commission cannot allow rates which are greater than those contained in the Company's proposed tariffs. While rejecting the specific legal argument of the Staff concerning the attrition allowance, however, the Commission cannot accept the Company's attrition allowance proposal in this case, for the reasons set out above.

## VIII. Rate Design

### A. Electric

Company proposes to allocate the increase in electric revenue to be determined in this case, to all classes of service and, within those classes, to all rate schedules, with the exception of the residential electric space heating rate (#040), in the following manner: The energy or fuel related portion of the increase would be added to existing rates based upon a uniform per kilowatt hour (KWH) basis, and the remainder of the increase would be added to existing rates based upon a uniform percentage basis. Company proposes no increase in its residential electric space heating rate (#040).

Staff agrees with the Company that the energy or fuel related portion of the increase to be determined in this case should be added to existing rates based upon a uniform per KWH basis, and that the remainder of the increase should be added to existing rates based upon a uniform percentage basis. Staff disagrees, however, with Company's proposal not to increase the residential space heating rate (#040), and proposes a lesser increase to the electric space heating rate by increasing the winter excess usage block by only the energy or fuel related portion of the increase.

TWA proposes that the increase in electric revenues to be determined in this case should be allocated to all classes of service and, within those classes, to all rate schedules based upon a uniform percentage basis.

Public Counsel proposes that the increase in electric revenues to be determined in this case should be allocated to all classes of service and, within those classes, to all rate schedules based upon a uniform per KWH basis.

There is a direct relationship between fuel and purchased power, on the one hand, and each kilowatt-hour of electric power sold or generated, on the other. Company, Staff and Public Counsel all rely, at least in part, upon this fact for their proposed rate designs in this case. The proposals of Company and Staff apply the proportionate fuel cost to each kilowatt-hour (except under the space heating rate in Company's proposal). Company and Staff assert that by applying the remaining part of the increase to the rest of the rates on a percentage basis, a proper allocation of fixed costs, demand-related costs and customer-related costs, is achieved. Company and Staff assert that the methodologies proposed by them essentially maintain the status quo as to this Company's rate design, continuing the rate design policy established by the Commission in this Company's last two rate cases (i.e., ER-80-118 and ER-81-85). Company and Staff believe that no substantial rate restructuring should be undertaken for the Company until load research data, required by the Public Utility Regulatory Policies Act of 1978 and currently being accumulated, is available. Company and Staff also assert that TWA's proposal would result in the tail blocks of a declining block rate not picking up as much of an increase on a per-kilowatt hour basis as the first block. As a result, lower KWH users would receive more of an increase in rates. Further, Company and Staff assert that Public Counsel's proposal would result in tail blocks picking up a higher percentage increase. In addition, certain non-energy rates (e.g. demand rates), and minimum rates that do not include any consumption, would not receive any increase under Public Counsel's proposal.

Public Counsel asserts that it would be inappropriate to spread the increases in production operation and maintenance cost (production O & M) on a uniform percentage basis as proposed by Company and Staff, maintaining that there is also a direct relationship between each kilowatt hour produced and all variable costs (not just fuel) required to produce that KWH. Public Counsel modified its proposal on this issue in its brief, wherein it recommends that the first $8,389,000 of any increase granted in this case be spread on a uniform per KWH basis to all customers, and that any increase in excess of that amount be spread on a uniform percentage basis. The $8,389,000 figure is based upon the increase in production O & M (exclusive of fuel) and the increase in fuel and purchased power expense, between Case No. ER-81-85 and the instant case, as testified to by Staff witness Washburn on cross-examination by Public Counsel.

In support of its position, TWA asserts that industrial rates have risen at a higher percentage rate than residential rates since 1977. Since the Company's cost of service to industrial customers was lower than its cost of service to residential customers in 1977 (when the last cost of service study of MoPub was performed), and Company has not shown that any change in that situation has occurred since 1977, TWA concludes that industrial ratepayers are subsidizing residential ratepayers. The proposed percentage increase in residential rates by the Company in this case is in a range of 18.68% to 18.86%, while the proposed percentage increase for industrial users is 21.14%. The proposed increase for all classifications of users, totaled, is 18.35%. TWA asserts that the contribution to return of industrial users is higher than the contribution to return of residential users, and there is greater efficiency and less line-loss in supplying energy to industrial customers than to residential customers, resulting in less cost per kilowatt-hour. Since 1977, the industrial electric rate (Rate 210) of MoPub has been increasing by an average of 16.44% per year, while the residential rate has been increasing at 10.34% per year. TWA alleges that the rate designs proposed by Company, Staff and Public Counsel in this case would continue subsidization of residential electric rates by industrial users such as TWA, resulting in an undue or unreasonable preference to residential users at the expense of industrial users. TWA asserts that its proposed uniform percentage spreading of the increase in electric rates in this case would more accurately reflect the greater costs incurred by MoPub in providing service to residential customers.

However, application of a uniform increase to two different rates will, of necessity, result in a larger percentage increase to the lower rate (i.e., the industrial rate in this case). Without current class cost of service data, TWA's allegation of subsidization cannot be supported. Public Counsel's evidence demonstrates that production costs represent a substantially larger portion of the Company's cost of serving industrial customers as compared to residential customers. That evidence further demonstrates that the Company's total production costs, and in particular fuel costs, have risen more rapidly than other costs (transmission, distribution, administrative and general) in recent years. It follows, then, that the total cost of providing service to industrial customers is increasing more rapidly than the total costs associated with residential service. The evidence in this case further showed that energy production costs have increased since the Company's last rate case. It is clearly appropriate, therefore, that these energy production costs be spread on a per-kilowatt hour basis. The proposal of TWA on this issue must be rejected.

A remaining question is whether the residential electric space heating rate (#040) should bear any of the increase in electric rates resulting from this case. As stated earlier, Company proposes not to apply any of the increase in electric rates resulting from this case to Company's residential electric space heating rate. Company and Staff agree that, during the last five years, the electric space heating rate has experienced the greatest percentage increase (i.e., 163%) of any residential electric rate of the Company. Company believes that its proposal not to allocate any increase to the space heating rate in this case would encourage more utilization of Company's production, transmission and distribution systems and, thus, result in a higher load factor. Company contends that any improvement in load factor is of benefit to all of Company's customers. Company's load factor in 1981 was 42.5%, and averaged 44.4% for the five years ending 1980. By comparison, Union Electric Company had a 51.4% load factor, Kansas City Power & Light Company 49.02%, and The Empire District Electric Company 56.38%, for the same five year period. The five year average load factor for the 100 largest companies in the United States was 57.70%. The Commission cannot conclude, however, that it is just and reasonable to entirely insulate a particular class of customers from a rate increase which is based upon the Company's reasonable revenue requirement. The Commission concludes that Company and Staff's proposals concerning the residential electric space heating rate will be rejected.

Rather, the Commission concludes that the first $8,389,000 of any increase in electric rates authorized in this case should be allocated to all classes of service and, within those classes, to all rate schedules based upon a uniform per KWH basis. The Commission further concludes that any increase in electric rates in excess of $8,389,000 authorized in this case should be allocated to all classes of service and, within those classes, to all rate schedules based upon a uniform percentage basis. This rate design, proposed by Public Counsel in its brief, assures that increases in energy production costs will be directly distributed to customers on the basis of the customer's kilowatt-hour usage of such energy. Public Counsel's position is preferred by the Commission because it assigns on a per kilowatt-hour basis not only fuel costs and purchased power costs, as proposed by Staff and Company, but also production O & M costs. On the other hand, any increase in electric rates which exceeds these $8,389,000 in energy production costs will be spread on a uniform percentage basis, which represents a proper allocation of fixed costs, demand-related costs and customer-related costs.

For these reasons, the electric rate design proposed by the Public Counsel in its initial brief is hereby adopted for purposes of this case.

In addition, the Commission determines that a new docket should be created to accomodate a study of the rate design of this Company, and that the Company should be ordered to file in this new docket the results of the load research study in which it is currently engaged.

The Commission further determines that this Company should be directed to perform a new class cost of service study, to be filed in the rate design docket being created by this Report and Order. It is clear from the record of this case that current class cost of service data would facilitate determination of the proper allocation of electric rates among customer classes and subclasses. The Commission will anticipate proceedings in such a rate design docket during 1983.

B. Water

In the Hearing Memorandum in this case (Joint Exhibit No. 1), all parties agreed that the increase in water revenues to be determined in this case should be allocated to the appropriate rate schedules pursuant to the recommendation of Staff witness Nickle, as set forth in his prepared testimony and revised schedules in this case (Exhibits 4 and 11).

## IX. Water Issues

### A. Unaccounted-For Water

Staff asserts that the level of unaccounted-for water in Company's water operations is unreasonably high. Staff recommends an investigation into Company's unaccounted-for water levels, and further proposes an accounting adjustment in test-year expenses to represent what Staff considers to be a reasonable level of unaccounted-for water.

Unaccounted-for water is "the difference between the total net plant output delivered to the distribution system and the total measured quantity of water passing through customers' services for the same specified time...." The measured quantity of water could include actual customer meter readings as well as properly estimated unmetered usage. A system's percentage of unaccounted-for water is the difference between the quantity of water produced less the quantity of water sold, divided by the quantity of water produced.

Company experienced unaccounted-for water levels of 47.62%, 47.46%, and 58.11% in its Osceola operations in the years 1978, 1979 and 1980, respectively. In its Clinton operations, the Company experienced unaccounted-for water levels of 33.11%, 26.7% and 25.93% in each of those years. These figures mean, for example, that well over half of the water produced by the Company in Osceola in 1980 was neither reflected in metered sales nor otherwise accounted for. In the opinion of Staff's expert witness, 20% would be a reasonable level of unaccounted-for water for Company's Osceola system, because the system has long portions of main with few customers and many dead-end mains. In the opinion of the same Staff expert, 15%

would be a reasonable unaccounted-for water level for Company's Clinton system. Staff proposes to reduce Company's test-year expenses to reflect Staff's recommended reasonable levels of unaccounted-for water.

Unaccounted-for water can be caused by (1) the inaccuracy of the measuring device used in determining the inflow into the system, (2) the inaccuracy of the meters used for determining the water actually used by the customers, (3) the water actually wasted due to leaks and breaks in the piping system or distribution system, and/or (4) unmetered water used to flush streets, sewers, the water system and for firefighting.

By letter dated September 14, 1979, the Commission Staff advised the president of the Company that the Company needed to meter both raw and finished water at Clinton. That letter stated Staff's opinion that it was "important that these meters be kept in good repair so that the company may know how much unaccounted for water there is on each system." The same letter recommended that a meter be provided to the Cities of Osceola and Clinton so that water provided to each city for street flushing and sewer flushing could be measured. The letter further observed that fire flows would have to be estimated, but that the fire departments in Osceola and Clinton should provide the necessary information to make estimates of fire flows. Some time after receipt of Staff's letter, the Company did install master meters at the Clinton water plant. No other action was taken by Company in response to Staff's letter.

Company asserts that without further investigation and study, the unaccounted-for water percentages at Clinton and Osceola cannot be said to be unreasonable. Company states that it is going to test its master meters at Osceola and Clinton, and that "preliminary indications" are that the master meter at Osceola is reading too fast (i.e., is registering more water than is actually flowing through it). Company also states that it is going to more accurately quantify the amount of unmetered water which is used for fire fighting and flushing streets, sewers and the water system, and that Company has purchased leak survey equipment and is now training Company personnel to use this equipment, which will help the Company locate mains as well as possible leaks that might exist in the mains and services.

Of course, Staff had advised the Company some two-and-a-half years before the hearing in this case that it was important that Company's master meters be kept in good repair so that the Company could monitor unaccounted-for water on each system, and had recommended at the same time the provision of a meter to measure street and sewer flushing. Only after these matters became contested issues before the Commission in the instant case, however, does Company appear to have responded to Staff's proposals. The failure to test the master meter at the Osceola plant seems particularly remarkable since (1) the Company believes that the meter may be reading too fast, which could make it a significant source of unaccounted-for water, (2) the test will be performed by the meter supplier and will cost the Company nothing, (3) the test will not result in an interruption of service, and (4) the "preliminary indication" which brought the possibility of the malfunction of the master meter to the Company's attention was available to the Company in March or April of 1981.

Company also asserts that it has "implemented a program of testing and replacing customer meters on a regular basis." On cross-examination of Company's witness, however, it became clear that this "program" is a matter of replacing meters after the Company learns or has reason to suspect that there is something wrong with the meter (determined from observation of consumption records or personal observation by meter readers of damaged or leaking meters). The Commission's rules, at 4 CSR 240-10.030(38), require that the accuracy of a customer's meter be tested every ten (10) years or 200,000 cubic feet of usage, whichever occurs first. There is no evidence in the instant case that the Company has a program to implement, or does implement, this rule of the Commission.

Company asserts that, in light of the actions which are either being taken or will be taken by the Company, the recommendation of Staff that an investigation and study be performed relative to the unaccounted-for water becomes moot. Company further asserts that, until it has been determined after further investigation and study that the actual unaccounted-for water percentages are unreasonably high, it would not be appropriate to make Staff's proposed downward adjustment in actual test-year expenses based on some "hypothetical level" of unaccounted-for water.

Quite to the contrary, the demonstrably lackadaisical attitude of the Company concerning the issue of unaccounted-for water, dating back at least to the Staff's letter of September 14, 1979, in no wise gives this Commission confidence that the Company seriously intends to resolve this matter on its own. Further, the Company has had far more than an adequate period of time in which to determine what a reasonable level of unaccounted-for water would be for its Clinton and Osceola systems. No "hypothetical levels" should need to be considered, because Company should already be in a position to propose and prove an appropriate level of unaccounted-for water for its systems. However, Company is not in that position, either by choice or otherwise.

The Commission concludes that the Company should be ordered to investigate the level of unaccounted-for water experienced in its Clinton and Osceola water operations, and to file a report with the Commission at a date set out in the ORDERED sections of this Report and Order, explaining in detail the steps Company has taken to determine what is a reasonable level of unaccounted-for water for each of the Clinton and Osceola systems, and what steps have been taken to reduce the level of unaccounted-for water in those systems. The Commission Staff should be advised of every step of the Company's investigation, and invited to participate or observe all tests utilized by the Company in its investigation. The Company's report is to be filed in the Management Audit case of this Company (Case No. EO-82-171).

The Commission further concludes that Staff's recommended accounting adjustment, decreasing Company's test-year expenses based on Staff's recommended reasonable levels of unaccounted-for water, should be adopted.

B. Operating and Maintenance Expense

Staff recommends that Company perform an investigation of its water operations in order to justify its existing operation and maintenance (O & M) expense. Company opposes this recommendation.

Staff analyzed the service rates, ratio of total expense to number of customers, and ratio of operation and maintenance (O & M) expense on customer service lines per customer for the Missouri Public Service Company, and compared those figures with other regulated water companies in Missouri of similar age, plant investment per customer, and number of customers. The companies used for comparison were: The Brunswick, Mexico, Warrensburg and Platte County systems operated by Missouri Cities Water Company; the Lexington system run by Missouri Water Company; and The Empire District Electric Company's water operations. As a result of this analysis, Staff found that MoPub's proposed water rates in this case are approximately double those of the other companies; that MoPub's total expense to number of customers is 100% greater than the comparison companies as to MoPub's Clinton operation, and 50% greater as to MoPub's Osceola operation; and that MoPub's O & M on customer service lines per customer is 470% greater than the comparison companies as to MoPub's Clinton operations and 430% greater as to MoPub's Osceola operations. Based on these findings, Staff recommends that the Company should investigate its operations in order to justify its O & M expenses.

Company asserts, however, that its costs and rates have not been shown to be unreasonably high, and that the Company reviews its O & M expenses for all company operations "to make sure that increases...from one year to the next do not increase disproportionately or without justification." Company submits that its O & M expenses for water operations have not increased disproportionately with what would be reasonably anticipated as a result of general cost inflating factors such as labor increases, environmental requirements and inflation.

The comparison of increases in O & M expenses to general inflation factors is not the basis of Staff's recommendation on this issue. Rather, Staff's recommendation is based simply on the seemingly extraordinary fact that this Company's O & M expenditures per customer on service lines is 430% to 470% greater than such expenditures of comparable companies. In its brief, Staff suggests that:

> It would seem that prudent management, when advised of such findings, would be eager to participate in an investigation of these expenses in an effort to provide safe and adequate service in the most cost-efficient manner possible. In the absence of such receptiveness, the Staff must recommend that the Commission require the Company to perform such an investigation. Company has brought forth no reasonable basis to find otherwise.

The Commission agrees with Staff's analysis. The Commission will order the Company to investigate its water O & M expenses and to file a detailed report of its findings and analysis with the Commission, in the Management Audit cse of this Company (Case No. EO-82-171) by the date established in the ORDERED sections of this Report and Order, below.

C. Net Operating Income (Water)

After adjustments made on the basis of contested issues herein, the Commission finds Company's net water operating income under present rates to be $126,279 for its Clinton water operations, and $12,974 for its Osceola water operations.

D. Adjustment to Return on Water Rate Base

The Commission has discussed hereinabove the exceptionally high levels of unaccounted-for water which have been experienced by the Company in its water operations. As stated earlier, the Company's attitude toward these high levels of unaccounted-for water has been "demonstrably lackadaisical." Not only has the Company made no serious effort to reduce its levels of unaccounted-for water by its own initiative, but the Company in the instant case even went so far as to oppose Staff's recommendation that the matter be investigated. The Commission has also discussed in this Report and Order the operation and maintenance expenses of the Company's water system, noting that the Company's O & M expense on customer service lines per customer is 470% greater than that of six comparable water systems, as to MoPub's Clinton operations, and 430% greater as to its Osceola operations. Again, however, the Company's response in this case was not to analyze and support these operating and maintenance expenses but, rather, to oppose Staff's recommendation that the matter be further investigated, at all.

The Commission has made Staff's proposed adjustment decreasing Company's test-year expenses based on Staff's recommended reasonable levels of unaccounted-for water, and has ordered the Company to investigate its levels of unaccounted-for water and its water O & M expenses and to file reports in this Commission's pending Management Audit case concerning the Company (Case No. EO-82-171). However, it is the Commission's judgment that the management inefficiency, and disinterest in operational improvement, demonstrated upon this record requires additional ratemaking treatment.

The Commission concludes that the rate of return on water rate base in this case should be reduced by one percentage point, from 10.47% to 9.47%. (See section VII. B., above). This determination is clearly authorized by law. E.g., Bluefield Water Works & Improv. Company v. Public Service Commission, 262 U.S. 679, 693, 43 S. Ct. 675, 679, 67 L.Ed. 1177, 1183 (1923); Smyth v. Ames, 169 U.S. 466, 547, 18 S. Ct. 418, 42 L.ed. 819 (1897); D. C. Transit System v. Washington Metro. Area Transit Commission, 466 F.2d 394, 407-13, 418-23 (D.C. Cir. 1972). New Jersey v. New Jersey Bell Tel. Company, 30 N.J. 16, 152 A.2d 35, 42 (1959); State ex rel. Utility Commission v. General Tel. Company, 285 N.C. 671, 208 S.E.2d 681, 686-690 (1974); Petition of New England Tel. and Tel. Company, 115 Vt. 494, 66 A.2d 135, 147 (1949); Re: Middle States Utilities Company, 72 PUR (NS) 17, 28-30 (MoPSC 1947). See, Re: North Missouri Tel. Company, 49 PUR3d 313, 317-9 (MoPSC 1963); Re: Western Light & Tel. Company, 10 PUR3d 70, 74-76 (MoPSC 1955); Re: The United Tel. Company, 1 MoPSC (NS) 341, 349-50 (1948); Public Service Commission v. Missouri Utilities Company, 1932E PUR 449, 489 (MoPSC 1932); Re: Lexington Water Company, 1928E PUR 322, 345-6 (MoPSC 1928). See generally, Note, "Public Utility Law -- Public Service Commission Ordered Rebates for Inadequate Service," 1976 Wisc. L. Rev. 584 (1976); See cases cited at MoPSC Digest, Rates, sec. 25; MoPSC

Digest, Return, sec. 30; 4 PUR Digest (Cumulative), Rates, sec. 150; 5 PUR Digest (Cumulative), Return, sec. 36; 1 Priest, Principles of Public Utility Regulation: Theory & Application, 206-7 (1969); Nichols and Welch, Ruling Principles of Utility Regulation: Rate of Return, 382-95 (1955); Nichols and Welch, Ruling Principles of Utility Rate Regulation: Rate of Return (Supplement A), 303-7 (1964); Bonbright, Principles of Public Utility Regulation, 262-5 (1961); Note, "The Duty of A Public Utility To Render Adequate Service: Its Scope and Enforcement," 62 Colum. L. Rev. 312, 329-31 (1962); Note, "Public Utilities — Fair Rates for Fair Service," 53 N.C. L. Rev. 1083 (1975); Nolan, "Incentive Rate of Return," Public Utilities Fortnightly, 50 (July 30, 1981); Article, "Service, Efficiency and Rate of Return", Public Utilities Fortnightly, 46 (January 18, 1979). The Supreme Court of the United States left no doubt in its Bluefield decision that efficient and economic management must be considered in the context of setting the allowed return on a utility company's rate base:

> "The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit, and enable it to raise money necessary for the proper discharge of its public duties." (emphasis added)

Bluefield Water Works & Improv. Company v. Public Service Commission, supra, 262 U.S. at 693. This language makes it clear that the Commission must consider evidence regarding the efficiency and economy of management in order to determine a proper return for the Company. Moreover, since Bluefield, "[n]umerous other decisions have recognized that superior service commands a higher rate of return as a reward for management efficiency and, conversely, that inefficiency and inferior service merits a lower return." (emphasis added) Note, Wisc. L. Rev., supra at 594. Finally, it should be noted that the Missouri Commission has previously considered adjustments for management efficiency in its rate decisions. (See authorities cited above.)

An excellent statement of the relevant principles has been noted by Nichols and Welch, quoting a Michigan Commission ruling:

> The commission believes it proper to base its rate of return in some degree upon the economy and efficiency with which the utility in question serves the public. The owners of a utility who are alert and active at all times in an endeavor to serve their public at the lowest possible reasonable cost are entitled to be compensated for their efforts. The amount of money going to the owners of a utility by way of return upon the fair value of the property used and useful in serving the public is ordinarily rather a small proportion of the total amount the patrons of the utility are required to pay. By far the greater amount the public is required to pay is used up in operating expenses, taxes, and the maintenance of the property. Where the owners of a utility make use of every reasonable economy that will keep the operating expenses at the lowest possible reasonable figure, they can and should be granted a greater rate of return than they should receive where these efforts are not made. Assume two gas utilities existing under practically the same conditions; one of them through up-to-date methods is able to furnish gas to the public at a given price, while it costs the other 10 cents per M cubic feet more than it costs the first one. Should the owners of each utility receive the same rate of return? The commission thinks not. Enterprise, economy, and efficiency should receive some reward. The only means by which the owners of a utility can be compensated for their enterprise, efficiency, and economy is through the rate of return. Eight per cent is proper in some cases; 7 per cent or 6 per cent or possibly less would be sufficient in others. The commission will not hesitate to fix a higher rate of return where circumstances warrant it and conversely a lower rate of return will be fixed where conditions seem to demand it and this rate of return should be changed from time to time to correspond with the performance of the utility." (emphasis added)

Nichols and Welch, Ruling Principles of Utility Regulation: Rate of Return, 382-3 (1955).

In the Commission's judgment, a reduction of Company's rate of return on water rate base from 10.47 to 9.47 percent will both reflect the management inefficiency so clearly demonstrated by the record of this case concerning water issues and, hopefully, will provide an incentive to this Company to improve management efficiency. State commissions have gone much farther than has this Commission in this case. Re: Middle States Utilities Company, 72 PUR (NS) 17 (MoPSC 1947)(no increase); Re: Blair Telegraph Company,10 PUR4th 44,47-54 (NebPSC

1975)(Salaries cut; other accounts reduced); Re: Berkeley Water Company, unreported order (NJBdPUC Nos. 7811-1515, et al., November 6, 1980), cited at Nolan, supra, at 53 (company's manager removed; control transferred to receiver).

The Commission further would suggest to its Staff that it more closely scrutinize the rate increase requests of companies demonstrating the type of disregard for management efficiencies that MoPub has demonstrated in this case as to its water O & M and unaccounted-for water levels. The Commission would also urge its Staff to consider recommendations such as reductions in allowable operating expenses and returns on rate base, when they find the type of evidence contained herein as to the issues of water O & M and unaccounted-for water. The Commission must wonder whether a company which cannot be bothered to investigate the fact that more than half the water it produces in a given town vanishes without accountability, can in fact meet its burden of proving a need for any increase in rates at all. However, the Commission cannot conclude upon the evidence before it that no water rate increase is justified.

E. Clinton Feeder Line

Staff recommends that the Company complete construction of the feeder main line to the north end of Clinton as soon as practicable. This feeder line was included in the Phase 4 recommendations of an engineering study performed by the Layne-Western Company, Inc., a consulting engineering firm, in approximately December, 1978. The Layne-Western study recommended the extension of a twelve-inch line from Golden Drive, north across Highways 13 and 7, to the north end of the existing six-inch line along Gaines Drive, crossing Highways 13 and 7. This proposed line is what is referred to herein as the Clinton Feeder Line. The Layne-Western report recommended the use of either twelve-inch or fourteen-inch pipe for the Clinton Feeder Line. Staff's witness testified that it is the Company's responsibility to determine what size feeder line is required.

On February 18, 1982, a member of the Commission's Staff performed a water pressure test in the presence of personnel of the Company, the Missouri Department of

Natural Resources (DNR), and the Clinton Fire Department. When a fire hydrant in north Clinton was flowed (opened) in that test, the residual water pressure at one nearby residence on the system dropped from 70 pounds per square inch (psi) to five psi. Since the residual pressure at the location tested was five psi, pressure at certain other locations on the system could possibly have gone to zero, or beyond zero, to create a vacuum. The creation of a vacuum in any part of the water system could result in cross contamination in the water line, creating a health hazard, from siphonage of water back into the system from improperly constructed plumbing fixtures (such as the reservoir tank on the back of flush toilets, or washing-tanks from various pieces of medical equipment). Zero residual water pressures can also cause damage to water meters as a result of hot water heater drainage back into the water system.

On March 8, 1982, another member of the Commission's Staff conducted additional pressure testing at various locations in the north part of Clinton, assisted by personnel of the Company, DNR and Clinton Fire Department. Two different fire hydrants were opened, one at a time, for purposes of these additional tests. The second hydrant was opened on two different occasions. When the first hydrant was flowed through a one-and-a-half inch opening, residual pressure at a hose connection on a nearby house went from 75 psi to 20 psi, and residual pressure at a hose connection on another house in the area went from 64 psi to 13 psi. Residual pressure on the ground floor of a hospital went from 70 psi to 22 psi. Residual pressures on the third floor of the hospital would have been about 12 psi less than those on the first floor, due to the difference in elevation only.

When the second hydrant was flowed through a one-and-a-half inch opening, the hose connection at one residence showed a change in residual pressure from 75 psi to 19 psi, and that at the second residence was reduced from 60 psi to 10 psi. Residual pressure on the ground floor of the hospital went from 70 psi to 20 psi. Upon flowing the second hydrant through a two-and-a-half inch opening, residual pressure at the hose connection on the first house was reduced from 75 psi to zero psi, and that on the second house was reduced from 60 psi to zero psi, while the residual pressure at the ground floor of the hospital went from 70 psi to ten psi. Due to the difference in elevation it was likely, therefore, that residual pressure on the third floor was less than zero.

The Commission's rules, at 4 CSR 240-10.030(34) provide that "dead ends" in distributing mains should be flushed when necessary to insure satisfactory quality of water to consumers and that, to allow flushing, dead ends should be equipped with hydrants, flush valves or other means of allowing water to be removed from such dead ends. The water system in Clinton contains many dead ends which require flushing.

The Commission's rules at 4 CSR 240-10.030(32) provide:

> All water furnished by utilities for human consumption and general household purposes shall conform to standards adopted by the Missouri State Division of Health. The source of supply shall be of adequate quantity to insure a supply without interruption at all times.

Section (35) of the same rule provides, in part:

> Every effort must be made to maintain water pressure which will at no time fall below an adequate minimum pressure suitable for domestic service.

The standards adopted by the Missouri Department of Natural Resources, (successor to the Missouri State Division of Health as to public water supply responsibilities), require 20 psi of pressure throughout the water system under all normal operating conditions. The necessity of flushing mains is a normal operating condition of the Company. The Company has also undertaken to provide fire service to the Fire Department of the City of Clinton and, therefore, the provision of fire flows is also a part of the normal operating conditions of this system. The system, as it exists, is not adequate to assure residual pressures of no less than 20 psi throughout the system under normal operating conditions.

In order to fight a fire at a residence in north Clinton, the Clinton Fire Department would initially respond with two vehicles and would attack the fire with two inch and three-quarter firelines from the nearest fire hydrant. The fire department would also request from fire headquarters two additional tanker units for backup supply, which would come in already loaded with water. If their water supply was depleted during the course of fighting the fire, the tankers would have to proceed south through a major intersection and continue south to Sedalia Street in Clinton to reload from a larger water main. If the new Clinton Feeder Line was constructed, the initial attack pumper would be at the fire, and the second pumper would pump off the fire hydrant into the attack unit.

At Golden Valley Memorial Hospital, which is located in the area of north Clinton in question, initial attack would be from a fire hydrant (hydrant 121) located at the hospital, and the second pumper would go to a pond located some 500 to 600 feet west of the hospital to begin drafting procedures to supply fire units at the hospital for fire attack. Water from the pond cannot be pumped into the sprinkler system at the hospital because of possible contamination of the Company's water system. No use of pond water would be required for firefighting at the hospital, if the new Clinton Feeder Line was constructed. Current water pressure flows available in the Company's system may not provide sufficient water pressure for effective utilization of the sprinkler systems in the hospital or in the Clinton Manor project nearby.

Section 393.130, RSMo 1978, provides that:

> Every gas corporation, every electrical corporation, every water corporation, and every sewer corporation shall furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable.

Section 393.140, RSMo 1978, states, in part, that the Commission shall:

> (2) Investigate and ascertain, from time to time, the quality of...water supplied...by persons and corporations...and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using such...water...system...and have power to order reasonable improvements and extensions of the works,...pipes, lines,...and other reasonable devices, apparatus and property of...water corporations....

Thus, this Commission has a duty to investigate the quality of Company's service, and the Company has a duty to provide safe and adequate service. The Commission is further empowered by statute to order reasonable improvements in the Company's system.

Upon the record herein, the Commission concludes that the inability of Company's system to maintain residual pressures of no less than 20 psi in north Clinton while a fire hydrant is being flowed is unsafe and inadequate, and must be corrected. The evidence herein is clear that a larger feeder line is necessary to assure such minimum residual pressures in the case of fire flow or flushing. Therefore, the Commission concludes that the Company should be ordered to construct a new feeder main line to the north end of Clinton, of sufficient size to provide adequate (not less than 20 psi) residual pressures under the conditions discussed herein, for the reasonably foreseeable future. Company will be directed, in the ORDERED sections of this Report and Order, to file with the Commission, within thirty (30) days, a construction schedule for such a feeder line.

The Company asserts that it is under no requirement to maintain water pressure at any specific levels (i.e., 20 psi), and that the requirement of providing safe and adequate water service relates only to domestic service and not fire protection service, because of the provisions of the Commission's rule at 4 CSR 240-10.030(35). That rule states:

> Every effort must be made to maintain water pressure which will at no time fall below an adequate minimum pressure suitable for domestic service. In addition to furnishing domestic and commercial service, each utility furnishing fire hydrant service must be able, within a reasonable period of time after notice, to supply fire-hydrant service to local firefighting equipment and facilities. No utility shall, however, be required to install larger mains or fire hydrants or otherwise supply fire service, unless proper contractual arrangements shall have been made with the utility by the municipality, agency or individual desiring such service. (Emphasis added).

The Company's position is not well taken. Under this rule, the Company would not be required to install larger mains or fire hydrants, unless proper contractual arrangements had been made, in order to provide fire service not previously undertaken by the utility. In the City of Clinton, however, the Company has already undertaken the provision of fire service to the City at some time in the past. The effort to apply the provisions of 4 CSR 240-10.030(35) in the instant case is not timely. The supply of fire service is not being requested in this case. What is at issue is the Company's inability to provide minimum residual pressures (determined herein to be 20 psi or more) when hydrants which are already in place are flowed for fire fighting or system flushing purposes. The flowing of hydrants for these purposes have already been determined (hereinabove) to be part of the "normal operating conditions" of the Company's water system in Clinton. As a result, the reduction of residual pressures to a level below 20 psi when a hydrant is flowed is inadequate for domestic service, under 10.030(35). The minimum pressure suitable for domestic service, as found herein, is 20 psi. To provide that minimum pressure, a larger feeder main is needed. The Company's arguments must be rejected.

F. Quality of Clinton Water

A great deal of testimony was presented to the Commission at the Clinton local hearings on February 18, 1982 concerning the quality (including bad taste and odor) of water provided by the Company to its Clinton customers in or about July, 1981, and again in or about January, 1982. (See transcript of local public hearing, T-1 through 107; also, T-727-730). At the evidentiary hearings in Jefferson City, Staff's witness testified as to steps the Company could take, and has taken, to improve the quality of water provided to customers in the City of Clinton.

The Commission concludes that the Company should be ordered and directed to take all steps necessary to avoid the problems concerning the quality (including the odor and taste) of water provided to customers in the City of Clinton which were experienced in or about July, 1981 and in or about January, 1982. Further, the Commission will direct its Staff to monitor the level of quality of the water provided to customers in Clinton, and to report to the Commission if, in Staff's judgment, further Commission action is necessary to maintain proper quality levels.

G. Looping of Dead-End Lines in Clinton

The Layne-Western report of December, 1978 (referred to hereinabove under section IX. E., "Clinton Feeder Line"), recommended, *inter alia*, the looping of all dead-end water mains in the Company's Clinton water system. Testimony at the local public hearings in Clinton indicated that of some twenty-two (22) dead-end lines within the city limits of Clinton, only six (6) had been looped as of the local hearings. Expert testimony at the evidentiary hearing in Jefferson City was that the quality of water can deteriorate on a dead-end line, and that dead-ends can cause or contribute to, *inter alia*, pressure problems and odor problems.

The Commission concludes that the Company should be ordered and directed to file a report with the Commission Staff detailing the Company's plans, including time-tables, for the looping of dead-ends in its Clinton water system. This report should be filed by the date set forth in the ORDERED sections below. The Staff will also be directed to report to the Commission if, in Staff's judgment, further Commission action is necessary concerning the looping of dead-end water lines.

X. Cold Weather Termination of Service Rule

The Hearing Memorandum in these cases (Joint Exhibit No. 1) set out the "Cold Weather Termination of Service Rule" as a contested issue. Two subparts of this issue were presented to the Commission in this case, upon stipulated facts (Exhibit 55). The first issue is whether Company may require customers who become delinquent between November 15 and March 15, to agree to eliminate any arrearage, current amounts and ensuing bills prior to the next June 15. The second subpart of the issue is whether the minimum 25% or $75 payment requirements of the rule apply separately to each utility service received (gas and electric) by a customer.

The Commission has adopted a rule relative to termination of utility services during periods of cold weather (hereinafter referred to as the "Cold Weather Rule" or "the rule"). The Cold Weather Rule is codified as 4 CSR 240-10.050. The rule provides, in Section (2) thereof, that:

During the period November 15 through March 15 heat related utility shall limit any discontinuance of service to residential customers receiving authorized heat related utility service who do not make a good faith attempt to pay....

Section (1)(A) of the rule defines "good faith attempt to pay," for purposes of the rule. Under that section, a customer has made a good faith attempt to pay if he or she has contacted the utility when a bill for service is not paid in full during the period November 15 through March 15, has stated his or her inability to pay in full and provided the utility with sufficient information regarding his or her income for determination of the terms of a payment agreement, and has entered into a payment agreement which includes "any amount in arrears, current amounts and all ensuing bills to be disposed of prior to the next November 15,...." 4 CSR 240-10.050(1)(A)1. The customer is also required to pay "a minimum of twenty five percent (25%) of the total monthly amount owed for service or seventy five dollars ($75) whichever is greater," [10.050(1)(A)2.], and to apply for financial assistance for heating bills for which he or she may be eligible.

Under the Cold Weather Rule, customers who do not make a good faith attempt to pay, within the provisions of the rule, may suffer a discontinuance of utility service.

Missouri Public Service Company ("Company") has not been granted a variance from the terms of the Cold Weather Rule. The Company has adopted certain procedures concerning its interpretation and implementation of the Cold Weather Rule, which Company applies in all geographical areas in which it renders service. These procedures of the Company require, inter alia, that between November 15 and March 15, electric, gas or gas and electric customers who have not paid their bills in full must sign an agreement "to include any amount in arrears, current amounts and all ensuing bills are to be paid by June 15", in order to avoid termination of service.

Public Counsel (who raised the instant issues in this case) argues that Company's policy of requiring an agreement to dispose of arrearages, current amounts and ensuing bills by June 15 is in clear violation of the provisions of the Cold

Weather Rule. Company argues, on the other hand, that Company's requirement that a customer eliminate any arrearage by June 15 is prior to November 15 and, therefore, well within the guidelines of the Commission's rule. Company asserts that in order for Public Counsel's argument to be meritorious, the rule would have to state that arrearages be eliminated no sooner than the next November 15.

The Commission concludes that the plain meaning of its Cold Weather Rule is that customers coming within its provisions are to be afforded the opportunity to pay any amount in arrears, current amounts and all ensuing bills over a period of time extending up until the next November 15, pursuant to a payment agreement entered into by the customer with the utility. To require that a customer who comes within the provisions of the Cold Weather Rule must enter into a payment agreement providing for the payment of all amounts in arrears, current amounts and all ensuing bills by June 15, at risk of termination of the customer's service, is a clear violation of both the spirit and letter of the Cold Weather Rule. Company could as easily argue that it could require payment of all amounts under the payment agreement by April 15 or some other date. In fact, every day beginning with November 15 is "prior to" the next November 15. Company's argument borders on the absurd, and seeks to wreak havoc with the uniform standards established by the Cold Weather Rule.

The Commission concludes that the Company should be ordered not to enforce its policy concerning the Cold Weather Rule, insofar as that policy requires a customer to sign an agreement to pay any amount in arrears, current amounts and all ensuing bills by June 15 in order to avoid termination of the customer's service. Any termination of service based upon such an agreement would violate the rules of this Commission. The Commission further concludes that any customer who came under the provisions of the Cold Weather Rule between November 15, 1981 and March 15, 1982 is entitled (1) to renegotiation of his or her payment agreement with the Company to provide for the payment of any amounts in arrears, current amounts and all ensuing bills to be disposed of prior to November 15, 1982, and (2) to be advised of that entitlement by the Company in case of the customer's failure to comply with his or her payment agreement on or after June 15, 1982. In order to assure that the policy of the Company found herein to be violative of the Commission's rule would not be enforced to result in a termination of service of any customer who came within the provisions of the Cold Weather Rule during the period November 15, 1981 and March 15, 1982, the Commission issued an "Interim Order Concerning Cold Weather Termination of Service Rule Issue" on June 15, 1982 in these cases, setting out these findings and conclusions of the Commission concerning Company's June 15 Cold Weather Rule payment deadline.

The second subpart of the Cold Weather Rule issue concerns the minimum payment requirements of the Cold Weather Rule [10.050(1)(A)(2.)]. The Company's procedures concerning interpretation and implementation of the Cold Weather Rule, referred to hereinabove, also require, inter alia, that customers coming under the Cold Weather Rule must pay a minimum of twenty five percent (25%) of the total monthly amount owed or seventy five dollars ($75), whichever is greater, "for each utility service received." The Company provides both gas and electric service to Missouri customers. Public Counsel contends that the minimum payment provision of the Cold Weather Rule should apply to the customer's total bill for service from the Company (including both gas and electric service), rather than being applied separately as to electric service and separately as to gas service. Public Counsel, in its brief, illustrates the result of the two interpretations of the rule advanced in this case, with a customer with a forced air gas furnace who receives a bill for a given winter month of $40 for electric services and $150 for gas. Under the Company's interpretation of the Cold Weather Rule, $75 would be due for gas service and the full amount ($40) would be due for electric service. By contrast, a customer in a total electric house with a bill of $190 would be required to pay $75 under Company's interpretation of the Cold Weather Rule. Under Public Counsel's interpretation, the first customer would be required to pay $75, since 25% of $190 (the total of electric and gas service) is $47.50. The second customer, in the total electric house, would not be affected by the different interpretations of the rule advanced in this case.

The Cold Weather Rule's prohibition against termination of service between November 15 and March 15 is limited to residential customers receiving authorized "heat related utility service." The rule, at 10.050(1)(B), defines "heat related utility service" as "any gas or electric service that is necessary to the proper function and operation of the customer's heating equipment." Since electricity is necessary for the operation of the fan which distributes the warm air produced by a forced air gas furnace, both gas and electricity are clearly necessary to the proper function and operation of the heating equipment of a customer who has a forced air gas furnace. Such a customer is entitled, therefore, to seek application of the Cold Weather Rule as to both his or her gas and electric service.

As Company points out in its reply brief, a customer in St. Louis who sought to utilize the provisions of the Cold Weather Rule as to both his or her gas and electric service would have to go separately to Union Electric Company and Laclede Gas Company to seek application of the rule. It is clear that each of those companies would apply the minimum payment provisions of the Cold Weather Rule independently of the other. The customer would be required to pay 25% of his or her gas bill to Laclede, or $75, whichever was greater; and, in addition, to pay 25% of his or her electric bill to Union Electric Company, or $75, whichever was greater. Each of the utility companies (Laclede and Union Electric), in this example, would receive the benefit of the full minimum payment required by the Cold Weather Rule; and the rule would be applied on a uniform and consistent basis as to each customer who sought to use the Rule as to both electric and gas service.

On the other hand, Public Counsel's proposed interpretation would produce the result that utilities which provide both gas and electric service, and customers of those utilities, would be treated differently than companies which provide either gas or electric service (but not both) and customers of those companies. Public

Counsel's interpretation would not change the application of the minimum payment requirements as to customers of Union Electric or Laclede. The Rule clearly does not contemplate the impossible administrative and bookkeeping task of independent utility companies joining together to calculate the application of the minimum payment requirements of the Cold Weather Rule and allocating the proceeds of such minimum payments.

The issue can best be seen by an expansion of Public Counsel's hypothetical situation. If a customer of MoPub in Sedalia was billed, in December, $40 for electric service and $150 for gas service, he or she would only have to pay $75 to the Company to come within the provisions of the Cold Weather Rule, under Public Counsel's proposed interpretation. On the other hand, a resident of the City of St. Louis who received a $40 electric bill from Union Electric Company in December, and a $150 gas bill from Laclede Gas Company in the same month, would be required to pay the full amount of the electric bill under the Cold Weather Rule provisions, plus $75 on the gas bill to Laclede Gas, or a total of $115. UE would have received its full electric bill, and Laclede would have received $75 of its gas bill. MoPub, on the other hand, would have received only $75 of the total amounts due to it by the Sedalia customer.

The Commission must conclude, therefore, that Public Counsel's proposed interpretation of the minimum payment provisions of the Cold Weather Rule would result in inconsistent and discriminatory application of the Rule's provisions, which would be unjust and unreasonable as to both the utility company which provides both gas and electric service, and to the customers of companies which provide only gas or electric service.

The Commission concludes that the Company's policy concerning the minimum payment provisions of the Cold Weather Rule is just and reasonable, and consistent with the terms of that Rule.

The Commission notes that since Company's policy concerning the minimum payment provisions is clearly consistent with the terms of the Cold Weather Rule, any proposal which could be devised by the Public Counsel (or any other party) to accomplish a reduction of the total minimum payment required under the Cold Weather Rule, while still providing for consistent and uniform application of the Rule throughout the state, might best be addressed in a Petition for Rulemaking.

XI. Fair Value Rate Base

For purposes of this case, the Company proposes a computation of fair value rate base determined by weighting net replacement costs of Company's property, and net original cost of such property, at 50% each. While the Company's approach is novel, Company cites no authority or Commission precedent for its approach. The Commission determines that its customary basis for determining fair value rate base should be utilized in this case.

The Commission finds the Company's fair value rate base to be $347,262,061 for electric operations, $3,658,884 for Clinton water operations and $487,958 for Osceola water operations. These amounts include all necessary components of rate base. Applying the net operating income requirement of $27,209,152 for electric operations which has been found reasonable in this case to the electric fair value rate base produces a fair and reasonable rate thereon of 7.84%. Applying the net operating income requirement of $232,305 for Clinton water operations which has been found reasonable in this case to the Clinton water fair value rate base produces a fair and reasonable rate thereon of 6.35%. Applying the net operating income requirement of $25,755 for Osceola water operations which has been found reasonable in this case to the Osceola water fair value rate base produces a fair and reasonable rate thereon of 5.28%

XII. Revenue Deficiency

Based on the rate of return found to be proper herein, the Company's net operating income requirement for electric operations is $27,209,152, or $3,365,113 in addition to its net operating income under existing rates. Applying the proper allowance for income taxes as approved herein, the additional revenue requirement as a result of the findings in this case is $6,419,554 on an annual basis, exclusive of applicable gross receipts and franchise taxes.

Based on the rate of return found to be proper herein, the Company's net operating income requirement for Clinton water operations is $232,305, or $106,026 in addition to net operating income under existing rates. Applying the proper allowance for income taxes as approved herein, the additional revenue requirement as a result of the findings in this case is $203,196 on an annual basis, exclusive of applicable gross receipts and franchise taxes.

Based on the rate of return found to be proper herein, the Company's net operating income requirement for Osceola water operations is $25,755, or $12,781 in addition to net operating income under existing rates. Applying the proper allowance for income taxes as approved herein, the additional revenue requirement as a result of the findings in this case is $24,850 on an annual basis, exclusive of applicable gross receipts and franchise taxes.

## Conclusions

The Public Service Commission of Missouri reaches the following conclusions:

The Company is a public utility subject to the jurisdiction of this Commission pursuant to Chapters 386 and 393, RSMO, 1978.

The Company's tariffs which are the subject matter of this proceeding were suspended pursuant to authority vested in this Commission by Section 393.150, RSMo, 1978.

The burden of proof to show that the proposed increased rates are just and reasonable is upon the Company.

The Commission, after notice and hearing, may order a change in the rate, charge or rental, and any regulation or practice affecting the rate, charge or rental, and it may determine and prescribe the lawful rate, charge or rental and the lawful regulation or practice affecting said rate, charge or rental thereafter to be observed.

The Commission may consider all facts which, in its judgment, have any bearing upon a proper determination of the price to be charged with due regard, among other things, to a reasonable average return upon the capital actually expended and to the necessity of making reservations out of income for surplus and contingencies.

The order of this Commission is based upon competent and substantial evidence upon the whole record.

The Company's existing rates and charges for electric service are insufficient to yield reasonable compensation for electric service rendered by it in this state and, accordingly, revisions in the Company's applicable electric tariff charges, as herein authorized, are proper and appropriate and will yield the Company a fair return on the net original cost rate base or the fair value rate base found proper herein. Electric rates resulting from the authorized revisions will be fair, just, reasonable and sufficient and will not be unduly discriminatory or unduly preferential.

The Company's existing rates and charges for water service are insufficient to yield reasonable compensation for water service rendered by it in this state and, accordingly, revisions in the Company's applicable water tariff charges, as herein authorized, are proper and appropriate and will yield the Company a fair return on the net original cost rate base or the fair value rate base found proper herein. Water rates resulting from the authorized revisions will be fair, just, reasonable and sufficient and will not be unduly discriminatory or unduly preferential.

For ratemaking purposes, the Commission may accept a stipulation in settlement of any contested matter submitted by the parties. The Commission is of the opinion that the matters of agreement between the parties in this case are reasonable and proper and should be accepted.

All motions not heretofore ruled upon are denied and all objections not heretofore ruled upon are overruled.

The Company should file, in lieu of the proposed revised electric tariffs, new tariffs designed to increase gross electric revenues by approximately $6,419,554 exclusive of gross receipts and franchise taxes.

The Company should file, in lieu of the proposed revised water tariffs, new tariffs designed to increase gross water revenues for the Clinton water operations by approximately $203,196, exclusive of gross receipts and franchise taxes, and designed to increase gross water revenues for the Osceola water operations by approximately $24,850, exclusive of gross receipts and franchise taxes.

It is, therefore,

ORDERED: 1. That the proposed revised electric tariffs filed by Missouri Public Service Company in Case No. ER-82-39 are hereby disapproved, and the Company is authorized to file in lieu thereof, for approval by this Commission, permanent tariffs designed to increase gross revenues by approximately $6,419,554 on an annual basis, exclusive of gross receipts and franchise taxes.

ORDERED: 2. That the proposed revised water tariffs filed by Missouri Public Service Company in Case No. WR-82-50 are hereby disapproved, and the Company is authorized to file in lieu thereof, for approval by this Commission, permanent tariffs designed to increase gross revenues by approximately $203,196 on an annual basis, exclusive of gross receipts and franchise taxes, for Clinton water operations, and by approximately $24,850 on an annual basis, exclusive of gross receipts and franchise taxes, for Osceola water operations.

ORDERED: 3. That Case No. EO-82-287 be, and is hereby, established as a rate design proceeding for the Company, to be styled, "In the matter of the rate design of Missouri Public Service Company."

ORDERED: 4. That Missouri Public Service Company be, and is hereby, ordered and directed to file the results of its load research study (referred to in this Report and Order above) in Case No. EO-82-287 on or before February 1, 1983, unless the Company petitions the Commission within sixty (60) days of the effective date of this Report and Order and clearly demonstrates that said requirement is unduly burdensome. This directive shall be applicable unless specifically waived by order of the Commission.

ORDERED: 5. That Missouri Public Service Company be, and is hereby, directed to perform a class cost of service study of its electric operations, and to file the results of such study in Case No. EO-82-287 on or before February 1, 1983, unless the Company petitions the Commission within sixty (60) days of the effective date of this Report and Order and clearly demonstrates that said requirement is unduly burdensome. This directive shall be applicable unless specifically waived by order of the Commission.

ORDERED: 6. That Missouri Public Service Company be, and is hereby, authorized to use "the Accelerated Cost Recovery System" for calculating depreciation for income tax deduction purposes and is further authorized to use a normalization method of accounting, as defined and prescribed in the Economic Recovery Tax Act of 1981, and as defined and prescribed in any rulings or regulations which might be promulgated to further explain or define the provisions of that Act.

ORDERED: 7. That Missouri Public Service Company be, and is hereby, ordered and directed to construct a new feeder main line to the north end of Clinton of sufficient size to provide adequate (not less than 20 psi) residual pressures under the conditions discussed hereinabove, for the reasonably foreseeable future, and to file with the Commission, within thirty (30) days of the effective date of this Report and Order, a construction schedule for construction of such feeder main line.

ORDERED: 8. That Missouri Public Service Company be, and is hereby, ordered and directed to investigate its levels of unaccounted-for water for each of the Clinton and Osceola water systems of the Company, and to file a report with the Commission on or before September 1, 1982 in Case No. EO-82-171 explaining in detail the steps Company has taken to determine what is a reasonable level of unaccounted-for water in each of those systems and what steps have been taken to reduce the level of unaccounted-for water in those systems, in accordance with the findings of the Commission hereinabove.

ORDERED: 9. That Missouri Public Service Company be, and is hereby, ordered and directed to investigate its water operating and maintenance expenses, and to file a report of its findings and analysis with the Commission on or before September 1, 1982 in Case No. EO-82-171 in accordance with the findings of the Commission hereinabove.

ORDERED: 10. That Missouri Public Service Company be, and is hereby, ordered and directed to take all steps necessary to avoid the problems concerning the quality (including the odor and taste) of water provided to customers in the City of Clinton which were experienced in or about July, 1981 and January, 1982.

ORDERED: 11. That the Commission Staff be, and is hereby, directed to monitor the level of quality (including odor and taste) of the water provided to customers in the City of Clinton, and to report to the Commission if, in Staff's judgment, further Commission action is necessary to maintain proper quality levels.

ORDERED: 12. That Missouri Public Service Company be, and is hereby, ordered and directed to file a report with the Commission Staff, on or before September 1, 1982, detailing the Company's plans (including time-tables) for the looping of dead-ends in the Company's Clinton water system.

ORDERED: 13. That the Commission Staff be, and is hereby, directed to report to the Commission if, in Staff's judgment, further Commission action is necessary concerning the looping of dead-end water lines.

ORDERED: 14. That Missouri Public Service Company be, and is hereby, ordered and directed not to enforce its policy of requiring that customers who come within the provisions of the Commission's Cold Weather Rule (4 CSR 240-10.050) be required, in order to avoid termination of service, to sign an agreement to pay any amount in arrears, current amounts and all ensuing bills by June 15.

ORDERED: 15. That Missouri Public Service Company be, and is hereby, ordered and directed to enter into a revised payment agreement with any customer who came within the provisions of the Cold Weather Rule between November 15, 1981 and March 15, 1982, upon request of any such customer, which revised payment agreement shall provide for the payment of any amount in arrears, current amounts and all ensuing bills to be disposed of prior to November 15, 1982.

ORDERED: 16. That Missouri Public Service Company be, and is hereby, ordered and directed to advise any customer who came within the provisions of the Cold Weather Rule between November 15, 1981 and March 15, 1982 and who, on or after June 15, 1982, fails to meet the obligations of his or her payment agreement with the Company pursuant to said Cold Weather Rule, that he or she is entitled to enter into a revised payment agreement providing for the payment of remaining amounts in arrears, current amounts and all ensuing bills on a schedule ending November 14, 1982.

ORDERED: 17. That Missouri Public Service Company shall file the electric and water tariffs in compliance with this Report and Order on or before June 28, 1982, using the rate design approved by this Report and Order.

ORDERED: 18. That the rates established in the tariffs authorized herein may be effective for electric and water service rendered on and after the 1st day of July, 1982.

ORDERED: 19. That this Report and Order shall become effective on the 1st day of July, 1982.

BY THE COMMISSION

Harvey G. Hubbs

Harvey G. Hubbs
Secretary

(S E A L)

Fraas, Chm., McCartney, Dority, Shapleigh and Musgrave, CC., Concur and certify compliance with the provisions of Section 536.080, RSMo, 1978.

Dated at Jefferson City, Missouri, on this 21st day of June, 1982.