BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

Union Electric

In the matter of the determination of in-service criteria for the Union Electric Company's Callaway Nuclear Plant and Callaway rate base and related issues.	)	Case No. EO-85-17
In the matter of Union Electric Company of St. Louis, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the company. (Filing January 15, 1985).	)	Case No. ER-85-160

APPEARANCES: Paul A. Agathen, General Attorney, James J. Cook, Juanita Feigenbaum, and Michael F. Barnes, Attorneys, Union Electric Company, Post Office Box 149, St. Louis, Missouri 63166,

and

Gerald Charnoff, Attorney at Law, 1800 M Street, N.W., Washington, D.C. 20036, for Union Electric Company.

Kenneth J. Neises, Attorney, Laclede Gas Company, 720 Olive Street, Room 1528, St. Louis, Missouri 63101, for Laclede Gas Company.

Michael Madsen, Attorney at Law, 211 East Capitol Avenue, Post Office Box 235, Jefferson City, Missouri 65102,

and

Boyd J. Springer, Attorney at Law, Three First National Plaza, Suite 5200, Chicago, Illinois 60602, for Dundee Cement Company.

Willard C. Reine, Attorney at Law, 314 East High Street, Jefferson City, Missouri 65101,

and

Sam Overfelt, Attorney at Law, 200 Madison Street, Post Office Box 1336, Jefferson City, Missouri 65102, for Missouri Retailers Association.

Robert C. Johnson, Attorney at Law, and George M. Pond, Attorney at Law, 720 Olive Street, 24th Floor, St. Louis, Missouri 63101, for: American Can Company; Anheuser-Busch, Inc.; Chrysler Corporation; Ford Motor Company; General Motors Corporation; Mallinckrodt, Inc.; McDonnell Douglas Corporation; Monsanto Company; National Can Corporation; Nooter Corporation; PPG Industries, Inc.; Pea Ridge Iron Ore Co.; River Cement Company; and St. Joe Minerals Corporation (Industrial Intervenors).

Richard S. Brownlee, III, Attorney at Law, Post Office Box 1069, Jefferson City, Missouri 65102, for Missouri Limestone Producers Association and Missouri LP Gas Association.

Gary Mayes, Attorney at Law, and Charles A. Newman, Attorney at Law, One Mercantile Center, St. Louis, Missouri 63101, for Metropolitan St. Louis Sewer District.

Robert C. McNicholas, Associate City Attorney, Room 314, City Hall, St. Louis, Missouri 63103, for the City of St. Louis and James J. Wilson, City Counselor.

Rollin J. Moerschel, Attorney at Law, 200 North Third Street, St. Charles, Missouri 63301, for the City of St. Peters, Missouri.

William M. Barvick, Attorney at Law, 231 Madison Street, Jefferson City, Missouri 65101, for the cities of Jefferson, Belle, Bevier, Elsberry, Kearney, Louisiana, Moberly, New Bloomfield, Mexico, Ashland, Troy, Greentop, Renick, Gorin, Cape Girardeau, Warrenton, Winfield, Lawson, Excelsior Springs, Wyaconda, Knox City, Boonville, Wood Heights, Charleston, Bowling Green, Center, Parma, Versailles, Edina, St. Charles and Eldon (Jefferson City, et al., or Cities).

Howard Hickman, Attorney at Law, 404 South Elson, Kirksville, Missouri 63501, for the City of Kirksville, Missouri.

Fred Boeckmann, Attorney at Law, 401 Independence, Cape Girardeau, Missouri 63701, for the City of Cape Girardeau, Missouri.

William Clark. Kelly, Assistant Attorney General, Office of the Attorney General, Post Office Box 899, Jefferson City, Missouri 65102, for the State of Missouri.

Tom Ryan, Attorney at Law, 4144 Lindell, St. Louis, Missouri 63108, for Missouri Public Interest Research Group.

E. Massey Watson, Attorney at Law, 1310 Old 63 South, Columbia, Missouri 65201, for Missouri Coalition for the Environment and Electric Ratepayers Protection Project.

Douglas M. Brooks, Public Counsel, Richard W. French, First Assistant Public Counsel, and Daniel Maher, Assistant Public Counsel, Office of Public Counsel, Post Office Box 7800, Jefferson City, Missouri 65102, for the Office of Public Counsel and the public.

Kent M. Ragsdale, General Counsel, William C. Harrelson, General Counsel, Edward J. Cadieux, Deputy General Counsel, A. Scott Cauger, Martin C. Rothfelder, Paul H. Gardner, Michael C. Pendergast, Thomas M. Byrne, and Linda K. Malinowski, Assistants General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

UNION ELECTRIC COMPANY

Case Nos. EO-85-17 and ER-85-160

Index of Contents

Page No.

Page No.

REPORT AND ORDER

Procedural History

On February 15, 1984, the Union Electric Company of St. Louis, Missouri, (hereinafter UE) submitted to the Commission proposed tariffs reflecting increased rates for electric service provided to customers in the Missouri service area of the Company. The case was docketed ER-84-168. The proposed tariffs were designed to produce an increase of approximately 65 percent ($639 million) in charges for electric services. UE also submitted alternative "rate phase-in" tariff sheets which were designed to implement the increase over a period of five years. The "rate phase-in" tariff sheets would produce a 25 percent increase in 1985 with increases of approximately 8 percent per year occurring each year thereafter through 1989.

On March 5, 1984, UE filed a motion requesting the Commission to establish an early intervention date; to establish an early date for pleadings and for oral argument regarding UE's request in paragraph 2 of its motion for synchronizing the "in service" date and ratemaking treatment of the Callaway Plant; and to establish an expedited schedule for hearings, briefing and Commission resolution of the "in-service" criteria to be applied to the Callaway Nuclear Plant. On March 7, 1984, the Commission suspended the proposed tariffs from March 16, 1984 to July 14, 1984, unless otherwise ordered; set an intervention deadline for April 6, 1984; set a filing date for responses to UE's synchronization request; and scheduled oral argument on UE's sychronization request for April 25, 1984, to be followed by a prehearing conference for the purpose of establishing a recommended schedule of proceedings.

Oral argument was heard on the synchronization issue on April 25, 1984, followed by a prehearing conference. On May 1, 1984, the parties submitted a recommended schedule of proceedings.

On May 11, 1984, the Commission issued its Second Suspension Order further suspending the proposed tariffs until January 14, 1985. The Commission's second suspension order scheduled proceedings in four phases as follows: Phase I - in-service criteria; Phase II - non-Callaway issues, rate of return, allocations, and rate design; Phase III - Callaway and rate base related issues; Phase IV - true-up proceedings.

The Commission also directed the parties to file responses addressing a procedure whereby in-service criteria and Callaway rate base and related issues would be addressed in a separate docket to be consolidated with Case No. ER-84-168 and later severed in the event the Callaway Nuclear Plant could not be found to be in service prior to the Commission's Report and Order in Case No. ER-84-168 was issued.

The parties were also directed to address continued accrual of AFUDC once the Callaway Plant is in service until the plant is allowed in rate base.

On June 29, 1984, the Commission issued its Order directing UE to provide notice to customers of the local hearings set in Cape Girardeau, St. Louis, Clayton, Jefferson City and Moberly.

The following parties were granted leave to intervene in these proceedings: the following cities located in the State of Missouri: St. Louis, St. Charles, Old Monroe, Boonville, Cape Girardeau, O'Fallon, Troy, Louisiana, Wentzville, Elsberry, St. Peters, Kirksville, Mexico, Versailles, Jefferson City, Excelsior Springs, Belle, Woods Heights, Lawson, Edina, Bevier, Eldon, Kearney, Shelbyville, Moberly, the State of Missouri, the Jefferson City school district, the Electric Ratepayers Protection Project, the Missouri Coalition for the Environment, the Missouri Public Interest Research Group, Laclede Gas Company, Missouri Limestone Producers, Dundee Cement Company, LP Gas Association, Missouri Retailers Association, the Metropolitan St. Louis Sewer District and the following Industrial Intervenors: American Can Company, Anheuser Busch, Inc., Chrysler Corporation, Ford Motor Company, General Motors Corporation, Mallinckrodt, Inc., McDonnell Douglas Corporation, Monsanto Company, National Can Corporation, Nooter Corporation, PPG Industries, Inc., Pea Ridge Iron Ore Company, River Cement Company, St. Joe Minerals Corporation (Monsanto et al.).

On July 13, 1984, the Commission initiated Docket No. EO-85-17 for the purpose of determining the "in-service criteria" to be used by the Commission for the Callaway Nuclear Plant and for the purpose of determining Callaway rate base and related issues. The Commission consolidated Case No. EO-85-17 with ER-84-168 to be heard on the existing schedule of proceedings. The procedure outlined by the Commission provided that if the Callaway Plant is not found to be in-service when the Commission issues its Report and Order in Case No. ER-84-168, Case No. EO-85-17 would be severed from Case No. ER-84-168 and would be consolidated with a new tariff filing reflecting the inclusion of the Callaway Plant. All parties to Case No. ER-84-168 were made parties to Case No. EO-85-17.

The Phase I hearings were held July 17 through July 20, 1984, for the purpose of establishing in-service criteria. On August 22, 1984, the Commission issued its Report and Order establishing criteria to be used for the determination of when the Callaway Nuclear Plant is "in-service" in order to be eligible for rate base inclusion.

On September 6, 1984, the parties presented to the Commission a Stipulation and Agreement for Phase II on all issues but rate design and rate of return. On September 11, 1984, and November 8, 1984, the parties filed amendments to the Stipulation and Agreement.

Hearings were held addressing Phase II, rate design issues on September 10, through September 14, 1984.

On September 11, 1984, Staff filed its motion for modification of hearing schedule for the Phase III portion of the proceedings and on September 18, 1984, UE filed its reply to Staff's motion. On September 20, 1984, the Commission held oral argument to address UE's and Staff's request for modification of the hearing schedule.

On September 21, 1984, the Commission issued its Order modifying rebuttal and surrebuttal filing dates for Phase III. The order continued cross-examination to November 13 through November 21, 1984 and December 3 through December 13, 1984. The Commission recognized in its order that UE's projected "in service" date for Callaway was January 5, 1985, and that additional hearings would be required to verify that the Callaway Plant is in service. The Commission further noted that it was apparent that the Callaway rate base and related issues could not be addressed and determined in Case No. ER-84-168 and any tariffs authorized in ER-84-168 would not include the Callaway Nuclear Plant. Further, the Commission ordered the parties to the rate design portion of Phase II to include in their rate design briefs their positions regarding rate design for tariffs which would be limited to Phase II recovery.

On September 27, 1984, the Commission further modified the Phase III schedule of proceedings changing the filing dates for surrebuttal testimony and scheduling cross-examination for November 13 through November 19, 1984, and December 4 through December 21, 1984.

Hearings were held addressing the Phase II rate of return issue on October 26 and October 29, 1984.

Phase III hearings addressing Callaway rate base and related issues were held November 13 through November 19, 1984, and December 3 through December 21, 1984. A Stipulation and Agreement on Phase II true-up was presented to the Commission on December 20, 1984.

On December 21, 1984, UE filed its "Notice of Completion of In-Service Criteria".

On January 4, 1985, the Commission issued its Report and Order in Case No. ER-84-168 authorizing a revenue increase related to Phase II - non-Callaway revenue requirement of $18,880,977.

The Commission incorporated the record of ER-84-168 pertaining to rate of return and rate design into EO-85-17. In addition, the Commission severed EO-85-17 from ER-84-168. The Commission stated in the Report and Order that all issues addressed in EO-85-17 would be determined by the Commission when the Commission issued its Report and Order in EO-85-17 and its related tariff filing.

On January 15, 1985, UE submitted to the Commission proposed tariffs which are identical to the tariffs originally filed in Case No. ER-84-168 as corrected by UE's filing received July 16, 1984. The new tariff filing was docketed as Case No. ER-85-160. On January 25, 1985, the Commission Staff filed its "Review of Fully Operational Status of the Callaway Nuclear Plant Unit I". On January 30, 1985, the Commission issued an order expressing the opinion that since no issue existed between Staff and UE regarding the in-service status of the Callaway plant, no further hearings need be scheduled to address in-service issues unless some party showed a cause that further hearings should be held.

On February 5, 1985, the Commission suspended the proposed tariffs filed in Case No. ER-85-160 until June 14, 1985, unless otherwise ordered. In that order, the Commission consolidated Case No. ER-85-160 with Case No. EO-85-17 and made all parties to EO-85-17 parties to ER-85-160.

On February 19, 1985, Staff filed a motion requesting the Commission to schedule true-up proceedings. On February 21, 1985, the Commission established a schedule for true-up proceedings.

On March 7, 1985, the true-up hearing was convened. Staff, UE and Public Counsel presented a stipulation resolving all issues.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact.

I. Introduction - Callaway In-service Status

In this rate case, UE proposes to include in rate base the cost associated with the construction of the Callaway Nuclear Plant. The Hearing Memorandum indicates that on a total company basis, the total rate base associated with the Callaway plant is $2,987,248,000, of which $2,403,406,000 is applicable to Missouri jurisdictional operations. The exhibits presented to the Commission during the true-up proceedings show UE proposed Callaway rate base for Missouri jurisdictional to be $2,442,300,000.

In light of the fact that the cost of Callaway exceeded the definitive estimate by approximately $2,000,000,000, (including approximately $1 billion of direct construction costs and approximately $1 billion in additional carrying costs or AFUDC), the evidence and arguments in this case have focused on issues involving allegedly unjustifiable cost overruns. Various parties have proposed disallowances to the Commission based upon theories of inefficiency, imprudence, burden of proof, economic benefits and the sharing of risks between the shareholders and ratepayers. The Commission will address these issues in subsequent sections of this order set forth below.

On August 22, 1984, in Case Nos. ER-84-168 and EO-85-17, the Commission issued its Report and Order establishing "in-service" criteria to be followed for determining when the Callaway plant would be "in-service" for ratemaking purposes.

The "in-service" criteria established by the Commission is set forth below.

Criterion 1. The UE's Startup Testing Program, which is outlined in Exhibit A4, Schedule A, shall be successfully completed. This shall include a successful uninterrupted run of at least 100 hours during which power is furnished to the grid at a level between 95 percent and 100 percent. 100 percent if 3425 MW thermal with a gross turbine output of 1185.8 MWe.

Criterion 2. The Preoperational Test program shall be successfully completed.

Criterion 3. The plant and associated transmission facilities have been tested capable of supplying to the Company's Missouri customers their full share of its rated power and can do so with the single most critical transmission line out of service.

Criterion 4. On the effective date of the Commission's order allowing rate recognition of the Callaway Plant, all licenses in jurisdictions other than the Missouri PSC which are needed to allow the plant to operate continuously at full power shall have been issued or acceptable commitments obtained.

Criterion 5. The plant's operating and NRC compliance history shows evidence of Company competence. For each delay of over 100 hours of a milestone event contained in Exhibit A4, Schedule A, covering the period from beginning of fuel load to successful completion of the NSSS acceptance test, the cause shall have been satisfactorily explained and acceptable measures taken to prevent recurrence. The Company shall meet with Staff biweekly for the purpose of briefing Staff on the status of startup testing and provide explanations of any slips in the schedule. The Company shall have complied with all NRC requirements and all corrections shall have been accepted by the NRC as a result of NRC violations.

Criterion 6. Exemptions from Criterion 1-5 may be granted or the determination made that the plant is "fully operational" at some power level less than the rated full power originally proposed for good cause shown.

Criterion 7. The plant is supplying electricity to the Company's system with output scheduled by the system load dispatcher.

On December 21, 1984, UE filed its motion of completion of "in-service" criteria, accompanied by affidavits and schedules of Mr. John F. McLaughlin. The affidavit states that the Callaway plant went into service as established by the criteria at 9:30 a.m., December 19, 1984.

On January 28, 1985, Staff filed its review of the fully operational status of the Callaway plant. Staff's review concludes that UE has complied with the Commission's "in-service" criteria as established by the Commission. No party has contested the "in-service" status of the plant.

Having considered UE's affidavits and supporting materials related to Callaway "in-service" status and Staff's review of the same, the Commission finds and concludes that the Callaway Nuclear Plant met the Commission's "in-Service" criteria on December 19, 1984, and that AFUDC shall be allowed to continue to accrue on the plant, for ratemaking purposes, from that date through March 15, 1985 (as stipulated by the parties), subject to specific adjustments and disallowances as discussed below.

II. General Management Performance

A. Industry Comparisons

1. Callaway Costs

Evidence was presented showing comparisons of the cost of Callaway with costs of other nuclear plants. UE witness Schnell compared Callaway costs exclusive of AFUDC with units beginning commercial operations two years before and three years after Callaway. The plant costs ranged from $1,021 per kilowatt to $2,677 per kilowatt, excluding Shoreham, Midland and Zimmer (troubled or canceled plants). Callaway, which is shown at $1,585 per kilowatt, compares favorably with costs experienced by utilities constructing their first nuclear units. Of the 15 first unit plants, Callaway ranks ninth from the lowest in cost. Of 29 plants, Callaway ranks thirteenth lowest in cost.

UE witness Stone compared Callaway with other first unit plants. Including AFUDC, Callaway is below the mean cost of $2,960 per kilowatt. UE witness Crowley used data from 10-K reports to the Securities and Exchange Commission to make his comparisons. The comparison included single unit plants, and follow on units which were significantly different from earlier units. The plants were under construction as of December 31, 1983. In terms of current dollars with and without AFUDC, and constant dollars with and without AFUDC, Callaway is below the median cost plant. Callaway showed lower than average construction schedule, commodity quantities and engineering hours, and higher than average craft hours.

Staff witnesses O'Brien and Serdikoff compared Callaway with post TMI units including AFUDC. In mixed dollars, based on a total cost of $3 billion, Callaway costs are shown as $2,545 per kilowatt. This compares to an average cost of $2,709 per kilowatt.

Public Counsel witness Rosen compared Callaway with all of the commercial light water reacters built in the United States through April, 1984, with the exception of six demonstration plants, fourteen "turnkey" plants and three other plants. Based upon his statistical analysis, he concluded that Callaway costs would be expected to be approximately $2.63 billion.

Based on the above comparisons, the Commission finds that Callaway costs approach the average cost experienced in the industry for the construction of nuclear plants.

2. Callaway Schedule

As noted above, Callaway received its construction permit in April of 1976, loaded fuel in June of 1984 and went into service in December of 1984.

Various comparisons have been presented to the Commission regarding schedule duration of other nuclear plants. The comparison of first unit plants presented by UE's witness Schnell shows schedule durations from construction permit to commercial operation ranging from 94 to 191 months. Callaway, at 105 months, is better than average in schedule performance for first unit plants.

UE witness Crowley's comparison shows an average schedule of 115 months from construction permit to fuel load. UE's schedule duration is shown as 97 months on his schedule although April, 1976 to June, 1984 is 99 months. The 99-month schedule is below the average schedule duration.

UE witness Stone compared 30 first unit plants completed or expected to be completed from 1979 to 1987 from the NSSS order to commercial operation. Callaway at 138 months is the lowest of the plants compared and is below the mean of 171 months. Construction duration from construction permit to commercial operation shows a mean of 130 months. Callaway, at 105 months, is one of the shortest duration for first unit plants constructed during this period.

Based on UE witness Huston's comparison of 13 plants, Callaway has the shortest schedule from start of engineering to commercial operation. The duration from first structural concrete to fuel load is shorter for Callaway than any of the other plants contained in the comparison, except Wolf Creek.

Based on the industry comparisons presented to the Commission, Callaway's schedule duration is better than the average schedule duration of nuclear plants completed in the same time period.

B. Standard

Under the Public Service Commission law, the Commission has the duty to set just and reasonable rates. A public utility must furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all repect just and reasonable. Every unjust or unreasonable charge is prohibited. Section 393.130(1), RSMo 1978.

At any hearing involving a rate sought to be increased, the burden of proof to show tht the increased rate or proposed increased rate is just and reasonable shall be upon the public utility. Section 393.150(2), RSMo 1978.

The Commission has the power to ascertain the value of the property of a public utility and every fact which in its judgment may or does have any bearing upon such value. 393.230(1), RSMo 1978.

In determining the price to be charged, the Commission may consider all facts which in its judgment have any bearing upon a proper determination of the question with due regard, among other things, to a reasonable average return upon capital actually expended and to the necessity of making reservations out of income for surplus and contingencies. Section 393.270(4), RSMo 1978.

The Legislature has granted the Commission broad discretion to set just and reasonable rates. State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission, 585 S.W.2d, 41 (1979). In the setting of just and reasonable rates, the Commission must balance investor and consumer interests. This principle was enunciated by the United States Supreme Court in Federal Power Commission v. Hope Natural Gas Company, 130 U.S. 591 (1944).

The United States Supreme Court established as far back as 1898 that a utility is entitled to ask a fair return upon the value of that which it employs for the public convenience. Smyth v. Ames, 169 U.S. 466 (1898).

In determining the reasonableness of rate base inclusion, the Commission determines that a utility is entitled to a fair return on its prudent investment in property devoted to public service. This principle has been developed from early United States Supreme Court cases, including Smyth, Hope, and State ex rel. Southwestern Bell Telephone Company v. Missouri Public Service Commission, 262, U.S. 276 (1923).

Based on the foregoing considerations, the Commission determines that UE has the burden of proving the reasonableness of the costs associated with Callaway. The Commission further determines that reasonableness should be judged using the standard of prudence. However, prudence requires further elucidation.

It is sometimes contended that management prudence is presumed. With respect to the question of the presumption of management prudence, the Commission agrees with the following conclusions of the Washington D.C. Circuit Court of Appeals:

> [11-13] The Federal Power Act imposes on the Company the "burden of proof to show that the increased rate or charge is just and reasonable." 16 U.S.C. §824d(e). Edison relies on Supreme Court precedent for the proposition that a utility's cost are presumed to be prudently incurred. See Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri Pub. Serv. Comm., 262 U.S. 276, 289 n.1 (1923). However, the presumption does not survive "a showing of inefficiency or improvidence." West Ohio Gas Co.v. Public Utilities Comm., 294 U.S. 63, 55 S.Ct. 316, 79 L.Ed. 761 (1935); see 1 A.L.G. Priest, Principles of Public Utility Regulation 50-51 (1969). As the Commission has explained, "utilities seeking a rate increase are not required to demonstrate in their cases-in-chief that all expenditures were prudent.... However, where some other participant in the proceeding creates a serious doubt as to the prudence of an expenditure, then the applicant has the burden of dispelling these doubts and proving the questioned expenditure to have been prudent." Opinion No. 86, Minnesota Power & Light Co. Opinion and Order on Rate Increase Filing, Docket No. ER76-827, at 14, 20 Fed. Power Service, 5-874, 5-887 (June 24, 1980) (footnotes omitted). Anaheim, Riverside, etc. v. F.E.R.C., 669 F2d 779 (D.C. Cir.1981).

In the Commission's opinion, the existence of $2 billion in cost overruns raises doubts as to prudence in this case. Therefore, UE has the burden of proof regarding prudence.

Staff and UE both agree that prudence is the appropriate standard to be used. Staff and UE both agree that prudence should not be based on hindsight. Rather, the standard should be a reasonableness standard.

UE states that prudence should be based on what could be expected of reasonable persons in the particular field of expertise under the same or similar circumstances. In applying this standard, UE proposes industry standards. UE's industry standards consist of charts and graphs showing costs and schedule duration of other nuclear plant projects. The average of these costs and schedules is claimed to be the industry standard.

The Commission determines that no industry standard of prudence has been established by UE. Over 100 nuclear plants have been cancelled since 1972. Some have been fraught with problems while others have been relatively successful. Mr. Schnell's schedule showing nuclear plant costs, excluding AFUDC, range from $1,121 per kilowatt to $3,491 per kilowatt. The average cost plant does not exist. No evidence was produced to show prudent management at any of the plants used in the schedules showing industry averages. The Commission concludes that industry averages do not create an industry standard of prudence.

UE has asserted that the project was very complex and that many problems are inherent in such projects. UE states in its initial Phase III brief - part A "...that the fast-tracking approach is known to produce certain inherent drawbacks". The Commission agrees that this is a factual statement but does not understand why UE would argue this as a reason for cost overruns as prudent management procedures would have factored these inherent drawbacks into its original cost estimate.

The Commission determines that the complexity of the project does not address the question of management prudence. The proper questions to ask are, "Did

UE properly manage this complex project? Did UE properly manage matters within its control?"

The Commission determines that the appropriate standard to be used in this case was enunciated by the New York Public Service Commission in Re: Consolidated Edison Company of New York, Inc., 45 P.U.R., 4th, 1982. In that case at page 331, the New York Commission rejected an earlier "rational basis" standard in favor of a reasonable care standard:

> More recently, and in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows:
>
> > "...the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Re: Consolidated Edison Company of New York, Inc., Opinion 79-1, January 16, 1979."

In reviewing UE's management of the Callaway project, the Commission will not rely on hindsight. The Commission will assess management decisions at the time they are made and ask the question, "Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?"

In accepting a reasonable care standard, the Commission does not adopt a standard of perfection. Perfection relies on hindsight. Under a reasonableness standard relevant factors to consider are the manner and timeliness in which problems were recognized and addressed. Perfection would require a trouble-free project.

Public utility regulation is based on the theory that a public utility is a natural monopoly since only one firm can efficiently serve a given market. To avoid monopoly pricing the state regulates the public utility to ensure reasonable rates. Thus, regulation is intended to serve as a surrogate for competition. The public utility is given a franchise to serve within a given area as a state-sanctioned monopoly and in return accepts the duty to serve all customers.

Because of the grave financial consequences which could accrue to captive monopoly ratepayers if a utility's investments were to prove uneconomic, the Commission determines that a standard of reasonable care requiring due diligence is appropriate for determining whether UE's actions during the course of the project were prudent.

C. Summary of Budget Estimates

In June of 1971, UE initiated plans for a nuclear plant to satisfy projected base load energy requirements for service in 1980. Studies were initiated concerning site selection. A location in Callaway County was ultimately chosen for the construction site.

In response to the Atomic Energy Commission's (AEC) encouragement of nuclear plant design standardization, UE entered into discussions with Northern States Power Company to explore the possibility of developing a standardized plant suitable for installation at similar sites. These discussions culminated in the establishment of the Standardized Nuclear Unit Power Plant System (SNUPPS) in early 1973 by a group of utilities with planned in-service dates as follows:

Northern States Power: two units - April, 1982 and October, 1983

Rochester Gas and Electric: one unit - October, 1982

Kansas Gas and Electric and Kansas City Power & Light:
one shared unit - April, 1981

Union Electric: two units - October, 1981 and April, 1983

The SNUPPS agreement, signed by each member utility, provided for a management committee comprised of an officer of each utility and a technical committee comprised of an engineer from each utility. Similar groups were established to handle quality assurance, construction, operations and legal matters. The management committee appointed a SNUPPS Executive Director to manage and coordinate the work of the member utilities.

The SNUPPS management committee selected Bechtel Power Corporation (Bechtel) to provide engineering and material procurement services for the standardized power block. In February of 1973 UE executed an agreement with Bechtel for engineering, procurement and home office services.

Westinghouse was chosen to manufacture the nuclear supply steam system (NSSS). In July of 1973, UE awarded a contract to Westinghouse and announced its decision to proceed with the project at the the Callaway site.

In November of 1973, General Electric received the order for the manufacture of the turbine generator. UE chose Sverdrup Parcel (S&P) to provide specific engineering services to supplement Bechtel's work on the standardized portion of the plant.

On April 30, 1974, UE submitted an application to AEC for permission to build Callaway I and 2. On June 7, 1974, UE submitted an application to this Commission for a certificate of convenience and necessity to construct Callaway Units No. 1 and 2. The Commission's Report and Order granting the certificate in Case No. 18,117 was issued March 14, 1975, and became effective on April 1, 1975.

The discussion which follows summarizes UE's budget estimates from 1975 through 1984, showing cost escalation and schedule delays throughout the course of the project.

The 1975 budget estimate for Callaway was $894.7 million. This estimate was based on the Bechtel preliminary estimate which was presented to the Commission in the certificate case. At the time the 1975 budget was prepared, the construction permit was projected for October, 1975, fuel load for June, 1981, and in-service for October, 1981. Based on these projected dates construction duration was expected to last 68 months from construction permit to fuel load.

In April, 1975, UE entered into an agreement with Daniel International Corporation (DIC) to be the constructor of the project. Site construction activities began in October of 1975, after the Nuclear Regulatory Commission (NRC) granted UE a limited work authorization (LWA) in August of 1975. The LWA allowed site preparation and other preliminary activities to proceed.

The 1976 budget estimate reduced the Callaway estimate to $779.5 million. This reduction was primarily due to a change in regulatory treatment by the Missouri Commission which allowed the recovery of the construction work in progress. In November of 1976, Proposition 1 was passed in Missouri prohibiting the recovery of construction work in progress. 393.135 RSMo, 1978.

The NRC construction permit was not received until April 16, 1976, six months later than anticipated.

Safety-related concrete placement commenced August 20, 1976. Difficulty in obtaining aggregate and design delays prevented extensive placement until the middle of November, 1976. At year end progress reports indicated that the project had slipped ten months.

The 1977 budget reflects the definitive estimate prepared by DIC and included $1.088 billion for Callaway I. In February of 1977, UE announced a one-year delay of the commercial operation date of Unit I to October, 1982, and a four-year delay of Unit II to April, 1987. Fuel load was delayed 10 months and commercial operation was delayed 12 months for Callaway I. Thus, schedule duration from construction permit to fuel load was 72 months and 78 months to commercial operation. The reason given by UE for the deferrals were delays in construction, restricted cash flow required to finance Unit II and declining load growth rates.

The 1978 budget included Callaway I at $1,138.6 million. The increases were primarily in the area of construction costs attributable to low productivity, which was 15 percent less than anticipated. Construction was reported to be 11 percent complete. Since only 71 percent of the schedule remained to complete 89 percent of the construction work, UE and DIC planned to accelerate manpower.

The 1979 budget estimated Callaway I costs at $1,202.8 million. Engineering was reported to be 75 percent complete and construction 27 percent complete. Delivery had slipped three months for the Westinghouse steam generator. The increases were attributed to the following factors: material costs had increased due to changes in specifications and actual cost experience; engineering costs increased due to changes in Callaway specific design and SNUPPS design evolution; construction costs increased because of projected remaining man-hours; and owners costs increased due to architect and engineering costs increases. UE reduced its contingency by $25.5 million because UE believed future uncertainties had been reduced. UE initiated a review of budget and schedule estimates and concluded that Unit I could be completed at the budgeted cost estimate.

In March of 1979, the Three Mile Island accident occurred. By the middle of 1979, Unit I was reported to be 44 percent complete. In July of 1979, Northern States Power terminated its participation in SNUPPS due to lowered projections in demand and lack of state regulatory approval.

Toward the end of 1979 construction was judged to be 50 percent complete. UE observed that it had taken three and one-half years to reach 50 percent completion. The schedule contemplated completion of the remaining 50 percent in two and one-half years.

By the end of 1979 UE submitted its operating license to the NRC. The NRC concluded that a realistic fuel load date was December, 1982, eight months later than UE's projection of April, 1982.

The 1980 budget projected total Callaway costs of $1,317.1 million. The largest increase was attributable to construction activity, (direct craft, indirect craft and overhead). Increases in engineering costs were attributed to design evolution and the cancellation of Northern States Power. Increases in owners costs were attributable to start-up operations. The contingency allowance was reduced by $1.2 million.

In January of 1980, Rochester Gas and Electric terminated its participation in SNUPPS due to lowered projection in demand. During the first quarter of 1980, UE became concerned over potential delays because of slow progress in the electric area, Further definition of completion of work and start-up was required. Meetings were held between Bechtel, DIC and UE to resolve priorities and finalize electrical work plans. Bechtel increased its efforts in conduit and cable design.

Laborers went on strike for a three-week period beginning April, 1980, and the operating engineers went on strike for two months in May, 1980. The last major concrete placement was for the containment building which was completed on July 27. 1980.

In October of 1980, UE announced a six month delay in the fuel load date to October, 1982 and commercial operation to April, 1983. This increased the construction duration to 78 months to fuel load and 84 months to commercial operation. The delay was attributed to labor strikes, electrical installation problems and TMI related changes. The NRC concluded that fuel load would not likely be achieved until February of 1983.

By the end of 1980, construction was believed to be 75 percent complete. Progress of electrical system installation was slow. UE believed that changes in construction logic and judicious use of shift work and overtime would make the October, 1982, fuel date achievable. Investigation of a potential problem regarding concrete in the outer surface of the containment building required additional time.

The 1981 budget estimate reflects the cost of Callaway at \$1,585.5 million. Construction costs rose by 20 percent over the previous estimate and were associated with increases in manpower. Material costs rose by ten percent and were attributed to regulatory changes, design evolution, plant improvement, schedule delay and escalation. Increases in engineering costs were attributed to regulatory changes, design evolution and plant improvement. The contingency allowance was increased because of escalation and increased work scope.

In April of 1981, Unit II was further deferred until April, 1990. As emphasis shifted to start-up it began to become apparent to UE that the amount of work required for completion of the project had been severely underestimated. The completion rate had dropped to .5 percent per month which UE attributed to the following problems: increased remaining work, lower craft productivity due to late material delivery, resolution of final design and regulatory changes.

In the fall of 1981, Unit I was extended an additional eight months. June, 1983, and early 1984 were established for fuel load and commercial operation. This increased the construction duration to 86 months to fuel load and 93 months to commercial operation.

In October of 1981, UE publicly announced the cancellation of Callaway Unit II, because of inability to finance the required cash flow and regulatory uncertainty.

The 1982 budget estimate was increased to $2,100,000,000, a 32 percent increase over the previous budget estimate. Most of the increase was attributed to the eight-month increase in schedule. AFUDC was increased by 49 percent, construction costs were increased by 32 percent, engineering costs were increased by 45 percent, and owners costs increased by 57 percent. The contingency allowance nearly doubled to $89.9 million.

By the middle of 1982, scheduling information indicated a potential seven-month slip in the fuel load date to January, 1984. Bechtel was indicating a ten to eleven month delay. UE adjusted the schedule date for fuel load by ten months to April, 1984, and commercial operation was scheduled for late 1984 or early 1985. The schedule duration was 96 months to fuel load and 105 months to commercial operation.

In August of 1982, UE and Daniel began to develop an integrated plan which encompassed all of the remaining engineering, construction and start-up testing identified as necessary to meet the April, 1984 fuel load date.

The 1983 budget estimate was $2,850,000,000. UE attributed nearly all of the increase to the ten-month extension in the construction schedule, and a better definition of work remaining. 600,000 man-hours were remaining in piping and hanger work and 500,000 man-hours were remaining in the electrical area.

AFUDC increased by 43 percent, construction cost increased by 19 percent, owners cost increased by 82 percent, engineering costs by 40 percent, material costs by 12 percent. The contingency was increased from $89.9 million to $129 million.

The 1984 budget estimate remained at $2,850,000,000. Engineering, construction, owners cost and material costs rose. AFUDC and contingency were reduced. Fuel load began in June, 1984, and the Callaway Plant went into service in December of 1985. A comparison of UE's 1977 budget estimate and UE's 1983 budget estimate is set forth below.

UE BUDGET ESTIMATES

(Millions of Dollars)

	January, 1977	January, 1984	Change
Engineering	41.0	235.0	194
Construction	240.5	696.8	456.3
Owners Costs	50.3	254.1	203.8
Materials	418.6	646.9	228.3
AFUDC	275.5	1,017.2	741.7
Contingency	62.1	- 0 -	(62.1)
Total	1,088.0	2,850.0	1,762.0

The following chart shows schedule delays through the course of the project:

SCHEDULE DELAYS

	Construction Permit	Fuel Load	No. of Months	Commercial Operation	No. of Months
Original	Oct., 1975	June, 1981	68	Oct., 1981	72
1977	April, 1976	April, 1982	72	Oct., 1982	78
1980	April, 1976	Oct., 1982	78	April, 1983	84
1981	April, 1976	June, 1983	86	Early, 1984	93
1982	April, 1976	April, 1984	96	Early, 1985	106
Actual	April, 1976	June, 1984	99	Dec., 1984	105

As is apparent from the charts set out above and the preceding discussion escalating budget estimates and schedule delays were significant problems throughout the Callaway project. As noted above, UE has updated its Callaway cost estimate to three billion dollars. Thus, the project experienced approximately two billion dollars in costs over the definitive estimate. The discussion which follows in Section II-D below will assess UE's management respecting overall control of the project cost and schedule.

D. UE Management Of The Project

Extensive testimony has been offered addressing UE's performance in managing the Callaway construction project. Management Analysis Company (MAC) performed an evaluation of UE's management performance which is contained in UE's Exhibit C-95, Schedule 1. O'Brien Kreitzberg and Associates, Inc. (OKA) performed an evaluation of management performance which is contained in Staff's Exhibit C-99-A. The MAC and OKA reports are comprehensive in nature and provide a broad overview of UE's management during the course of the project. Staff witness Renken, who recommends specific direct labor man-hour adjustments, also addresses management performance. The issue is also discussed by witnesses addressing overtime, SNUPPS/NPI and start up discussed in Section III-A4, A-12, A-13 below.

It is UE's position that its overall performance was excellent and that the Commission should evaluate UE's overall performance in determining to what extent the investment in Callaway should be recovered in rates.

It is Staff's position that UE did a creditable job managing the project with respect to quality although UE management was poor in other areas. Specifically, the Staff alleges that UE failed to coordinate the design and construction schedule to assure that design was sufficiently ahead of construction in order to enable construction to proceed in an efficient manner. In Staff's view, this alleged failure to properly coordinate design and construction caused inefficiencies, out of sequence work and rework, that could have been avoided.

Staff agrees that UE was prudent in choosing Bechtel as the architect-engineer and DIC as the constructor. Bechtel was the most experienced designer in the nuclear field. DIC had considerable experience as a builder of nuclear plants and, as the fourth largest contracting firm in the country, possessed the necessary level of supervisory and management talent. UE had considered various options regarding the approach to construction. Having considered various options, UE decided to choose a major constructor working under UE's general direction with the capability of constructing with open shop labor or union labor working under a project agreement. UE chose this option because UE believed it offered the maximum opportunity for control of cost and schedule and the final authority regarding construction decisions would rest with UE's management personnel. Under UE's approach Bechtel and Daniel provided their services under contract to UE which functioned as the overall integrator of the project.

UE contracted on a cost reimbursable basis (cost plus). Under this type of contract there is no fixed price commitment. Cost plus contracts have been standard in the utility industry for nuclear projects since 1967. Prior to that time utilities were able to contract for power plants on a "turnkey" basis. A "turnkey" contract established a firm cost which could only be affected by escalation. No party alleges that UE's cost plus contract approach was imprudent, since it has been established that contractors would proceed only on that basis.

The project was constructed on a fast-track basis. Under this approach, the design and construction implementation phases overlap since each phase typically takes several years on a major construction project. Overlapping can shorten a project by 25 to 50 percent.

In order for the fast-track concept to succeed, logical planning, sequencing, and coordinating of the design effort with the construction effort is required. Thus, it is essential that engineering be sequenced in order to support the construction process. No party opposes UE's utilization of the fast-track approach. However, Staff takes the position that UE did not properly coordinate design and construction within the parameters of the fast-track process.

Staff's position is partly based on a review of UE's documents and reports made throughout the course of the project and partly on direct observation at the site.

Bechtel, DIC and S&P all had different methods, procedures and computer programs to prepare estimates for monitoring and controlling progress. UE chose to monitor and control the performance of Bechtel, DIC and S&P with respect to the overall project by utilizing three different systems. UE hired a consultant, CMS, to manually integrate the three separate systems.

The engineering schedule utilized by Bechtel was a system known as CEBUS. This system was based on a drawing schedule with a date assigned for the projected release of drawings. DIC issued a series of critical path schedules. The project master critical path model (CPM) schedule (PMCS) was utilized to depict the overall schedule of the project at a computerized summary level of detail. There was also an intermediate range bar chart schedule (IRBCS) delineating PMCS activities during the next seven months. Initially the PMCS was to be derived from the intermediate level schedules developed by Bechtel. Later construction sequence logic and duration were altered to suit DIC's overall construction strategy. Schedule was maintained on a computer by DIC utilizing IBM's PROJAC system. The major scheduling tool for coordination of the project between Bechtel, NPI, S&P and UE was the seven month IRBCS. It is Staff's contention that these schedules were not integrated so that Bechtel and DIC could coordinate their schedules to assure efficient construction progress.

As noted above, construction of first structural concrete commenced in August of 1976. At that time engineering was believed to be 40 percent complete. In fact, engineering was 20 percent complete. Initial progress was slow because of the inability to procure aggregate. In addition, design problems related to rebar and structural steel surfaced at the commencement of the project. The SNUPPS management committee meeting of August 17, 1976, recognized problems related to material fabricated to approved drawings but not suited to design requirements and misfabricated material, some of which could be reworked in the field.

In the fall of 1976, a letter from Bechtel to SNUPPS informed SNUPPS that Bechtel was as much as 37 weeks behind its own schedule in civil design; that Bechtel was not tracking the construction schedule with the exception of monitoring DIC's three-month forecast schedule and that Bechtel's schedule was being seriously hampered by SNUPPS' practice of loading extra work on Bechtel outside the scope of the Bechtel definitive estimate while limiting Bechtel's manpower. The attachment to Bechtel's letter shows in most instances a three-month lead time of engineering in advance of construction. In many instances Bechtel was unable to achieve a three-month lead over construction.

The record reflects that prior to commencement of construction, Bechtel proposed to integrate the Bechtel intermediate schedule with the DIC intermediate schedule. UE and SNUPPS chose not to do this in order to keep control of the project with the utility rather than with Bechtel.

In January of 1977, UE's scheduling consultant, CMS, stated that production of Bechtel engineering drawings was behind and that the CEBUS monitoring report revealed that over 20 percent of the approximate 3,500 drawings and specifications had been rescheduled to be issued an average of five months later than the date originally forecasted. The report also noted that Bechtel was maintaining the appearance of remaining on schedule by constantly rescheduling target dates.

In February of 1977, UE acknowledged in a status report that Bechtel's schedule continued to slip and that concrete placement rates were 30 percent below the schedule required rate.

In early 1977, UE's documents cited potential delay in the delivery of rebar for the reactor building, misfabricated structural steel for the auxiliary building, misfabricated piping for the control building and late delivery with respect to other piping. In February of 1977, UE, SNUPPS and Bechtel were reviewing ways to accelerate civil engineering. DIC revised the critical path schedule in April of 1977 and again in May of 1977. Apparently Bechtel was attempting to provide a 90-day lead time ahead of DIC requirements.

In June of 1977, it was recognized that the auxiliary building and radwaste building were falling behind schedule because of DIC's inability to accomplish construction according to schedule; nonconforming reinforcing steel and embeds; absence of critical Bechtel drawings and materials; and NRC's stop work order.

In recognition of Bechtel's failure to supply quality materials and timely design a receipt inspection program was initiated at the site. During this period DIC was field fabricating rebar. However, large rebar could not be fabricated. It was recognized that scheduling problems were developing because of unavailability of drawings and materials.

In August of 1977, DIC proposed that the construction pace be restricted until efficient manpower and an effective schedule could be accomplished. This proposed measure addressed the failure of engineering and procurement to support construction.

The minutes of a SNUPPS meeting of September 20, 1977, states that completion of engineering work is unclear and information is lacking. The problem is traced to CEBUS in that the report states that CEBUS considers a drawing to be complete when issued as "revision 0". The report states that in many cases "revision 0" drawings are not complete lacking vendor details, hanger design, small pipe design, penetration and embed requirements. Thus, in many instances release drawings were lacking the details necessary for field construction.

In October of 1977, UE's monthly report continues to discuss slow field progress because of incomplete and continuing design problems and late delivery of fabricated items, particularly concrete reinforcing steel bars.

By the end of 1977, UE was reporting DIC's productivity at 95 percent, yet construction was just above 10 percent complete while 27 percent of the time had elapsed.

In February of 1978, UE's documents reflect that during the month of February DIC was able to work on 50 percent of items scheduled each week. One-half of the items not worked were attributed to untimely performance of design and procurement. It was noted that DIC was fabricating on site a substantial amount of reinforcing steel and concrete embeds because of late release of designs and design changes attributable to Bechtel.

During 1978, DIC increased manpower but experienced a loss of productivity. A considerable amount of piping was installed and supported on temporary hangers requiring permanent hangers at a later date.

In the summer of 1978, the SNUPPS committee discussed increasing Bechtel manpower to work on pipe stress analysis and hangers. A design freeze was discussed as well as a recognition that Bechtel's schedule was not an effective tool for purposes of supporting DIC construction and may not relate to the actual job status.

In January of 1979, UE reorganized its nuclear construction department. DIC manpower increased in the spring of 1979 and construction progress improved although productivity declined. In July of 1979, it was reported that deferred activities caused by entities other than DIC had dropped to 70 percent.

In October of 1979, UE realized that only two years remained to complete the remaining 50 percent of the project. At this time UE was beginning to plan start up and testing. In fact, the project was 35 percent complete.

In November of 1979, UE recognized a potential delay caused by design verification and delivery of class one pipe supports and whip restraints for the reactor building. At the end of 1979, UE was reporting improvement in all areas of construction. In January, 1980, Systems Coordinates, Inc., (SCI) recommended the use of Project 2 for start up scheduling rather than the IBM PROJACS which had been used by DIC. In March of 1980, UE began to engage outside consultants to commence start up with construction reported 61 percent complete. At the same time delays were occurring in electrical progress, delivery of electrical equipment, cable, pipe supports and whip restraints.

In June of 1980, UE reports reflected a problem regarding the classification of hangers as seismic under NRC II over I regulations. The effect of these regulations is discussed in Section III.A.1.g below.

During 1980, inadequate electrical performance was a major concern. Bulk electrical cable pulling had commenced in late 1979. Start up had begun prior to the completion of the bulk construction phase in the electrical area. UE later identified 270,000 man-hours of electric rework due to interferences between piping conduit and cable tray runs. In October of 1980, a UE memo stated that DIC was considered to be in default of its contract because of electrical problems. Productivity in the electrical area was restrained by the transition to start up and testing as well as by missing design information and materials.

In mid 1980, UE engaged MAC to perform an evaluation of the electrical work. MAC concluded that there was a need for better integration of plan and schedule; that there was a need for a homogeneous network compatible with the overall plan and schedule; that planning and scheduling was fragmented between engineering and construction; and that utilization of planning and scheduling procedures was less than optimum.

The MAC report identified the following areas in need of improvement:

1. The construction work as performed is not always consistent with the work as scheduled by the project construction schedule.

2. The electrical work assignment packages (i.e., work approved and available to DIC) are not effectively coordinated with the project construction schedule.

In addition, the following observation was set out in the executive summary of the report:

> "The greatest area of concern in the area of inter-organizational relationships is that UE has not fully exercised their rights as owners in managing the interface between Bechtel and DIC and the right to demand accountability to a project plan for all participants."

At year-end 1980, UE was commencing start-up testing. However, only 25 of the 54 sub-systems had been released for testing. In 1981, UE was using release for test dates based on the previous year's schedule. This schedule had not been updated to reflect the current status of the job or the over 100 missed milestone dates.

In January of 1981, a UE memo cites poor electrical performance as a jeopardy to the schedule as well as late design from Bechtel, late material delivery, (particularly cable), late field changes of vendor equipment, and late procurement of spare parts. The memo states that late design might be a major reason for DIC's poor performance and that the matter deserved further scrutiny. The memo states that Bechtel had conceded that it could not meet all DIC design and material need dates for the reactor coolant system, that Bechtel vendor rework plans had been late and most had involved design changes.

In April of 1981, UE formed a task force to develop a realistic schedule for the remaining work. The task force was made up of Bechtel, DIC, UE engineering and start up. UE determined that establishment of realistic engineering completion date was the first order of business.

In April of 1981, SNUPPS' technical committee imposed a design freeze on Bechtel. The minutes of the SNUPPS meeting reflect that no single document was used for identification and scheduling of all remaining project work.

Physical walk downs of the system were initiated in an attempt to establish the status of work. It was discovered that overreporting of construction progress had occurred in all areas. In addition, there was no valid quantity tracking system in any area except electrical. DIC was directed to increase manpower. UE determined that fuel load would have to be revised to mid 1983.

DIC requested that it be given overall responsibility for developing an integrated work plan encompassing engineering, procurement, construction and start-up. UE rejected DIC's request on the ground that it would detract from formulating creditable estimates of the amount of remaining work.

By the end of 1981, UE had a more accurate assessment of the status of the project. However, Bechtel was still producing revisions and new drawings. At year end 1981, it was reported that DIC's work was affected by 150 to 200 new drawings or drawing revisions per week.

By early 1982, UE became increasingly concerned that it had not adequately identified all the tasks necessary for system start-up and testing. UE's documents reflecting minutes at a company meeting dated March 11, 1982, reflects the following statement made by UE's vice president in charge of nuclear function: "We don't know where we are. We don't know how we are going to get this job done. We must find a way." Exhibit C-179, p. 47. DIC indicated a potential seven month slip in the schedule. Bechtel was engaged to conduct an independent assessment of the project. Bechtel indicated a potential 10 to 11 month extension of the schedule. In its report, Bechtel recommended improvement in the integration of an overall work planning process used for better coordination of the remaining completion and start-up activities at Callaway.

In June of 1982, UE personnel were still reporting lower than required progress in pipe hanger and electrical installation work in the reactor building. In August of 1982, UE was experiencing problems concerning the installation of surface mounted plates. These problems were attributed to congestion, rework and sign-off work.

A confidential task force report issued in August of 1982, indicated that electrical progress was being restrained by design changes and design release too close to construction. Cable and trays were affected by design changes, conditional release and work sequence.

UE directed DIC to establish a single integrated work plan encompassing the details and schedule logic of all remaining engineering, procurement, construction and start-up work. This was accomplished during the second half of 1982. DIC successfully integrated the construction schedule with start-up operations. For the remaining period of the Callaway project a computerized scheduling system called Project II was utilized for tracking and overall coordination. Project II was implemented in February of 1983.

Although problems continued through the end of the construction project, UE was able to control the project and successfully completed hot functional testing according to the existing schedule.

UE presented extensive rebuttal to Staff's evidence addressing coordination of design and construction. However, the evidence amounts primarily to general assertions containing few specific facts to support the assertions.

Company witness Traylor is the author of the MAC report. His rebuttal testimony addresses only two of the numerous references in the record to late design, only one of which suggests that late design did not affect construction or cause delay. This refers to the August, 1976 reference to misfabricated items. Mr. Traylor states that this problem related to testing procedures rather than construction delay.

Mr. Traylor describes the tools used to identify the performance of the project contractors against the approved project length and schedules. These tools consist of the various scheduling tools utilized by the various contractors: Bechtel's generic construction model for SNUPPS; Bechtel's network schedules which form the basis for CEBUS; Bethtel's generic intermediate schedule; annual estimates in budget; periodic Bechtel and DIC reports; UE management review; Bechtel's C/EW program; DIC's DCN process; DIC's CPN; and DIC's seven month and two week schedule.

Mr. Traylor concedes that there was no development of a single overall schedule encompassing all entities of the project. He maintains, however, that UE established interfaces between design and construction scheduling and between construction and start-up scheduling. These interfaces were accomplished through regular meetings held on a frequent basis. Mr. Traylor contends that these meetings were sufficient to deal with project problems. Mr. Traylor takes this position despite the criticism contained in the MAC report that UE was tardy in implementing a fully integrated work plan.

E. SNUPPS/NPI Management Of Design

UE and four other public utilities, Kansas City Power & Light Company (KCP&L), Northern States Power Company (NSP), Kansas Gas & Electric Company (KG&E) and Rochester Gas & Electric Company (RG&E), signed an agreement establishing SNUPPS on February 26, 1973. SNUPPS is the acronym for Standardized Nuclear Unit Power Plant System. It was formed to allow a standard design for building nuclear generating stations. The agreement between the utilities was amended in January 1974 to allow any utility to withdraw after a certain point in time. NSP and RG&E withdrew in 1979 and 1980, respectively, The utilities involved in SNUPPS controlled and shared the responsibilities over the joint activities of the project. Committees were formed to supervise various aspects of the project. The Management Committee had general supervision and control over all other committees and activities. Membership of the Management Committee came from the member utilities. UE, KCP&L and KG&E had the responsibility for the project after the other two utilities withdrew.

The utilities contracted with Nuclear Projects, Inc. (NPI) in 1974 to act as their agent in managing the design of the SNUPPS project. The Management Committee retained authority over NPI. NPI was to monitor the activities of the lead architect and engineer (A/E) and provide technical advice to the Management Committee concerning the project.

Bechtel Power Corporation (Bechtel) was the lead A/E. Bechtel was to design the power block and procure power block engineering materials. Bechtel was hired under a fixed fee plus costs contract. Bechtel's responsibility was to fully design and complete the project. NPI's major supervisory role was to monitor the activities of Bechtel and review Bechtel's efforts for the SNUPPS utilities. The four primary areas that NPI monitored were design scope, manning levels, schedule and productivity.

Staff contracted with an outside consultant to review the effectiveness of the SNUPPS/NPI organization in its monitoring and controlling of the activities of Bechtel. Staff hired Touche Ross & Company (Touche Ross), who contracted with Project Management Associates, Inc. (PMA), to perform the review. Touche Ross and PMA were asked to conduct an independent review of the SNUPPS/NPI management process and its effectiveness in administering Bechtel's contract. This review focused on design changes, costs and scheduling of the project. Touche Ross and PMA prepared a report which was introduced into evidence in this case. References to the report in this portion of the case will be to the report presented by Touche Ross & Company.

The Touche Ross report reached an overall conclusion that SNUPPS/NPI, and therefore UE, failed to adequately monitor the costs and schedule associated with the design of the Callaway Nuclear Plant. The report concluded that the personnel of SNUPPS did not have sufficient experience managing the construction of a nuclear plant to properly control the costs and schedule of design. The report states that SNUPPS made a good decision to obtain the services of NPI to help monitor Bechtel and provide technical assistance. This decision, though, was limited because SNUPPS limited the staffing of NPI and placed NPI's major emphasis on safety and quality of design. The report states further that NPI relied on Bechtel's reporting tools in order to monitor the costs and scheduling and so was dependent on Bechtel for information concerning Bechtel's performance. The report concludes that NPI's duties with regard to cost and schedule control were not specified, nor were procedures implemented to ensure proper interface between design and construction. NPI did not have an independent tool for reviewing Bechtel's overall progress, and therefore was unable to provide UE with accurate information concerning whether Bechtel was performing according to the projected schedule.

The report states that UE, as the owner utility, had primary responsibility for interface of design and construction. UE was aided by SNUPPS and NPI in its responsibilities. There was no mechanized system to enable UE or its representatives to determine if Bechtel was meeting the design schedule necessary for construction as projected. The report criticizes the use of group meetings to interface between design and construction, since this is the least effective means of control. NPI originally had responsibility only for coordinating the design schedule. This role changed eventually to involve some construction review. NPI relied primarily on group meetings as its primary source of review. The report concludes that SNUPPS's control of safety and quality of design of the Callaway Plant was very effective. This emphasis, though, did not carry over to cost and schedule control. Since NPI relied on Bechtel reports, it lacked an independent review of Bechtel's schedule progress. The report states: "Key information which was either not included in these reports or not consistently updated in the reports includes construction need dates, man-hour requirements for expediting designs with potential schedule impact, and the overall impact of Bechtel's readjusting its design schedule to react to near term problems."

Without a system for integrating the design and construction, SNUPPS and NPI could not assess the overall status of design and construction activities. Schedule Review Group meetings were held bimonthly to accomplish this interface. The report states that: "No formalized document exists which matched Daniel International Corporation (DIC) construction activities with the entire spectrum of requiring Bechtel design and procurement items required to support the ongoing schedule."

UE presented extensive evidence in response to the Touche Ross report. This evidence, though extensive, contained many conclusory assertions which were not supported by UE's evidence. UE first asserts that a look at the overall cost savings obtained by UE's utilizing the SNUPPS concept should offset any criticism or disallowance proposed by Staff. UE's witness Petrick argues generally that there were sufficient cost and schedule controls through SNUPPS and NPI to effectively monitor Bechtel. Petrick states that effective control of managing design, procurement, quality assurance and licensing show effectiveness of cost control. He states the most effective cost control is good design.

Petrick contends that the use of Bechtel information to monitor Bechtel was effective because Bechtel supplied adequate information to SNUPPS and NPI for the review. Petrick states that the periodic meetings held were an effective tool in controlling costs and schedule and that this enabled SNUPPS/NPI to ensure design production efficiently supported construction requirements.

After reviewing the evidence presented by Staff and UE, the Commission makes the following findings regarding the control of SNUPPS/NPI over the design of the Callaway Plant.

The Commission finds SNUPPS/NPI did not focus sufficient attention on cost and schedule control to ensure Bechtel was meeting the schedule requirements as projected. It took until 1981 for UE to determine that Bechtel was substantially behind in its design requirements. The Commission finds this can be attributed to the lack of experience of the SNUPPS utilities in nuclear construction and therefore the heavy reliance on Bechtel, and the utilities' failure to charge NPI with schedule interface responsibilities and to require an independent tool for monitoring design schedule. This was exacerbated by the failure to implement a mechanized system which would interface design and construction. UE did not know whether Bechtel was performing as expected because it was totally reliant on Bechtel information.

The fact that the decision to join SNUPPS was a sound decision by UE and saved costs with regard to building the Callaway Plant did not remove any of UE's responsibility for ensuring that the project was managed properly and that the costs of building the project were properly monitored. UE was expected to build the best plant at the lowest cost. UE focused primarily on the best plant portion of this requirement and did not place sufficient attention on cost control to ensure that the plant was built at the least possible cost.

The Commission rejects UE's contention that good design control ensures adequate costs and schedule control. The Callaway Plant is the perfect example of the failure of this proposition. Good design did not ensure cost control or schedule control at Callaway. Even UE's contention that regulatory requirements were the culprit for most of the cost overruns is not supported by the evidence with regard to design. Bechtel's reporting of the reasons for the need for additional work shows only that 31 percent of the additional design was required by changing regulations.

F. Summary of Conclusions Regarding Management of Project

After careful consideration of the competent and substantial evidence in the record and argument in briefs, the Commission concludes that UE has failed to meet the prudency standard, discussed above, which is necessary for full inclusion of all Callaway-related expenditures in rates. Although UE did a creditable job of managing many aspects of the Callaway project, there are exceptions which require significant disallowances in order to establish "just and reasonable" rates.

UE made the conscious decision to act as the overall manager of the Callaway project with Bechtel Corporation providing the architectural and engineering services and Daniel International Corporation acting as the major constructor. UE took this management approach since UE believed that it offered the maximum opportunity for control of cost and schedule. By taking this approach, UE assumed the role of overall coordinator of the engineering and construction schedules. UE, therefore, had the responsibility to integrate the engineering and construction schedules to insure the project was completed in a timely manner and at a reasonable cost. However, the Commission finds that UE failed to use due diligence to properly coordinate and integrate the construction schedule with the engineering schedule until late in the project.

The Commission concludes, based upon the overwhelming evidence in the record, that the regular meetings held by UE, Bechtel, DIC and other participants were not effective tools for exercising management control of the project and coordinating the engineering and construction schedules at the Callaway project. In fact, the evidence demonstrates that UE did not have a reasonable assessment of the status of the project until physical "walk downs" were accomplished late in the project in 1981, and an integrated schedule was put into place in 1983. As noted above, in 1982, UE's vice-president in charge of nuclear stated that UE did not know where they were. This is not a negative reflection on the officer who made the statement. Rather, it is a reflection on the corporate inefficiency which the officer recognized and ultimately took steps to correct.

The Commission finds that design was not sufficiently complete when construction began and that the problem continued throughout the project causing inefficiencies and delays. UE had notice of Bechtel's late performance in the fall of 1976. UE had notice that Bechtel's schedule was not reliable in early 1977. In August of 1977, DIC requested to cut back its work force because engineering and procurement efforts were not adequately supporting DIC's scheduled construction activities. Therefore, in the first year of construction UE knew or should have known that the project was not properly integrated and that construction had commenced prematurely. Rather than asserting management control at this early stage of the project, UE continued to push DIC instead of focusing on obtaining an accurate assessment of the overall project. This situation continued until 1982 when UE directed DIC to integrate the schedules for the remaining activities a year after DIC had requested authority to do so.

UE argues that the lack of an integrated construction plan did not affect the efficiency of the project. UE contends that the majority of overruns were caused by regulatory effects. UE presented a study that purports to show that on average $1 billion in cost overruns (excluding AFUDC) were experienced by nuclear plants with schedules comparable to the Callaway schedule.

Based upon this study, UE argues that approximately $1 billion in cost overruns (exclusive of AFUDC) at Callaway is attributable to regulatory changes, and therefore is justified. However, UE produced very little specific evidence tying NRC regulations to cost overruns at Callaway.

All parties agreed that regulatory change resulting from the Three Mile Island (TMI) incident had a dramatic impact upon the nuclear industry during Callaway's construction period. However, the evidence shows that most

TMI-related changes were anticipated by or incorporated into the SNUPPS design and that the majority of other safety-related standards, including Seismic II over I requirements, have been in effect since 1976. UE's witness Stone testified that the original SNUPPS design adequately considered potential Seismic II over I problems. (Ex. No. C-104, Schedule A, pp. I-II.) In addition, Staff's direct man-hour adjustments discussed in Section III-A1 below recommend the inclusion of all man-hours identified as being associated with regulatory changes, including man-hours related to quantities identified as regulatory-related in UE Witness Stone's testimony. The Commission therefore will not accept the contention that regulatory change alone adequately explains all of the cost overruns at the Callaway project.

UE did not fully implement its own project control manual which described the manner of crediting man-hours to cost codes. UE did not fully implement its quantity tracking system until 1982. Thus, UE's cost accounting system was not as effective as it might have been for most of the project. UE's performance as to cost accounting and quantity tracking is discussed in sections III.A.1. and 3. below.

Based upon the evidence in the record, the Commission finds that a significant part of the cost increases and delays at Callaway were due to factors within the control of UE management. However, other cost increases and delays were due to factors beyond the control of UE. These include changing regulatory requirements, increasing financing costs, increased costs associated with changes in plant design to enhance safety, improve efficiency and reliability, and changes in construction procedures to insure quality construction.

In the following sections of this Report and Order, the Commission will discuss specific issues relating to the Callaway project. We conclude that approximately $383,716,000 of the Callaway-related rate base expenditures and associated AFUDC should not be recovered from ratepayers since they represent inefficient, imprudent, unreasonable or unexplained costs.

III. Callaway Capital Costs

A. Staff Adjustments

1. Direct Man-hours - Summary

Staff recommends certain adjustments related to DIC direct labor man-hours. The adjusted definitive estimate as contained in Exhibit C-193-CJRA Revised 1, shows total man-hours of 11,581,928. A total of 21,900,841 man-hours were expended on the project. Staff recommends that 16,379,954 man-hours be allowed. Staff's disallowance of 5,520,887 man-hours converted to dollars, amounts to a rate base adjustment of $66,193,000.

Direct labor refers to work associated with the physical completion of the plant. Workers involved in this activity include carpenters, electricians, pipe fitters and laborers, etc.

The definitive estimate was based on the design scope as defined in Bechtel's definitive estimate. Staff based its man-hours audit on the definitive estimate, particularly the unit rates and unitized costs for installation of components.

The definitive estimate provided for changes on the basis of a change in scope of an account due to a change in the estimated escalation for labor or material. DIC updates to the definitive estimate were provided through estimate change notices (ECN). A related document is the estimate transfer notice (ETN). ETNs transfer man-hours and dollars from one category of cost to another.

Staff witness C. J. Renken audited all ECNs and ETNs as well as other UE documents explaining man-hour overruns.

In the Commission's opinion the definitive estimate is the proper starting point for an investigation of cost overruns and a determination as to whether cost incurred on the project are reasonable. The definitive estimate was based on licensing and regulatory procedures known when the estimate was made. Thus, based on the professional expertise of Bechtel and DIC, one would expect the definitive estimate to contain reasonable projections of the man-hours required to complete the job. The definitive estimate has been utilized by the Commission as a starting point for determining cost overruns.

> In Case No. ER-77-118, Re: Kansas City Power & Light Company, the Commission was of "the opinion that the appropriate starting point for the calculation of any cost overrun would be the target used by the Company in controlling cost." The Commission is of the opinion, as in Case No. ER-77-118, that the Company's definitive estimate is the appropriate starting point for determining cost overruns. Kansas City Power & Light Company, 24 Mo. P.S.C. (N.S.), (1981).

Since it is known that changes may occur over time, changes to the definitive estimate are to be expected. It is not true, as asserted by UE, that Staff has unreasonably held UE to the definitive estimate in spite of all the changes that have occurred since the definitive estimate was prepared. Staff used the definitive estimate as a starting point and has prepared its own estimate incorporating changes in construction scope and unit rate increases based on actual experience.

UE was unable to quantify many of the man-hours associated with the cost overruns. UE had no system in place which enabled it to track the cause of the overruns during the course of the project. As Staff points out, if Staff had required this type of documentation, Staff would have declared the project unauditable.

UE ordered DIC to produce, after the fact, ECNs quantifying the overruns. Although the ECNs accomplished no useful cost control purpose they did provide some explanation of the overruns. However, the ECNs did not cover all cost overruns. As a result, many overruns were not quantified and the ECNs were supplemented by general explanations.

For most of the unquantified overruns, Staff witness Renken has concluded that they were caused by poor integration of design and construction resulting in inefficiencies. For others, Staff witness Renken established his own estimate based on Wolf Creek experience. Since Wolf Creek is the other SNUPPS unit constructed approximately six months to a year behind Callaway, the use of this data is appropriate as the plants are comparable. Other unquantified overruns were simply rejected by Staff because they were not plausibly explained. Most of the quantified overruns contained in the ECNs were accepted by Mr. Renken unless they were related to late design. In addition, Mr. Renken has increased the contingency and increased unit rates in some areas.

The Commission does not understand why UE did not track escalating costs by their causes. UE knew that it would have to prove the reasonableness of the expenditures when it sought to include the plant in rate base. Thus, it would be in the interest of its shareholders, as well as its ratepayers, to track escalating costs and the reasons for such costs. In addition, the absence of an effective cost tracking system by cause seriously hindered the ability to control the cost during the course of the project.

It has not been established that such a cost tracking system could not be achieved. In fact, UE witness Crowley stated in a paper entitled "Nuclear Power Plant Cost Drivers" prepared for the Department of Energy:

> Accurate and consistent data on plant design and construction performance characteristics would provide a basis for comparison and aid in establishing reaslistic goals. Currently, it is often the case that much of the project data that is kept is of little use to management, except as historical records. Site project control personnel can easily cost on the order of $10 million for a single unit. They should be more than historians.

DIC had a system that could have been utilized for such a purpose. The record reflects that most of the necessary reporting and computing tools were available to track increased costs as they were incurred, identify their cause and predict future costs. This system was only partially utilized by project management.

UE has the burden of proof to show that the costs expended on the project were just and reasonable. The Commission determines that UE has not met its burden in the areas where Staff has disallowed man-hours. Accordingly, $66,193,000 associated with DIC direct labor man-hours will be disallowed.

Mr. Renken's man-hour adjustments are shown in the chart set forth below which is followed by a discussion of each category.

		Adjusted D.E.	Recommendation	As Built
1.	Sitework (Outside Area)	298,068	1,353,652	1,353,652
2.	Civil/structural/finishes (Outside Area)	253,578	325,105	581,671
3.	Electrical (Outside Area)	405,066	818,292	983,503
4.	Civil	2,253,498	2,709,041	4,782,886
5.	Structural Steel	299,183	524,800	1,140,983
6.	Finishes	138,120	179,764	333,244
7.	Mechanical Equipment	592,883	942,003	1,052,826
8.	Instrumentation	286,941	336,689	374,036
9.	Hangers	902,141	1,541,619	2,328,358
10.	Piping, Erection and Welding	1,798,540	2,139,821	2,322,862
11.	Piping, Cleaning and Flushing	289,760	308,394	635,735
12.	Piping, Whip Restraints	32,967	32,967	182,781
13.	Electrical	1,552,009	2,113,689	3,784,625
14.	Scaffolding	556,938	766,287	1,502,571
15.	ESWS	236,936	271,014	541,108
16.	Contingency (see Appendix A-1)	1,763,236	1,763,236	-
17.	Allowance for reduction in night shift productivity	159,000	253,581	-
		11,818,864	16,379,954	21,900,841

a. Outside area

The outside area describes all structures and improvements to the plant site not located within or immediately adjacent to the power block buildings. The outside area encompasses three subcategories: sitework; civil/structural finishes; and electrical. The adjusted definitive estimate man-hours for sitework is reflected as 298,068, while the as-built man-hours are 1,353,652. Staff included all as-built man-hours in the sitework subcategory.

In the civil/structural finishes subcategory the adjusted definitive estimate is 253,578 compared to the as-built total of 581,671. Staff recommends 325,105 man-hours for this subcategory. Staff recommends 818,292 man-hours in the electrical subcategory. This compares with the as-built man-hour level of 983,503 and the adjusted definitive estimate level of 405,066 man-hours.

In its recommendation for outside civil/structural finishes and electrical, Staff has accounted for all ECNs and ETNs relating to the subcategories. An unquantified amount still exists between the ETN and ECN totals and the as-built totals. The Company attributes these differences to backfill operations, dewatering, adverse weather conditions and design evolution. Staff accepted UE's explanation regarding backfill, dewatering and adverse weather conditions in the site work subcategory but not for the other two subcategories.

With respect to design evolution, Staff included outside facilities added after the definitive estimates such as the secondary access facility, the technical support center, the health calibration lab, UE office facilities and start-up buildings.

UE's explanations in the civil/structural finishes category described congestion and inefficient craft sequencing because of additional structural steel roof members which were added to the water treatment plant to support installed piping in order to prevent roof sagging. UE maintains that design evolution and weather interfered with the proper sequencing of duct bank completion in order to avoid interference. In addition, since some drawings were issued for construction with manholes on "hold", because of incomplete design, duct bank and manhole concrete could not be completed simultaneously.

In the electrical area, UE states that as design evolved the addition of duct bank and underground piping necessitated electrical installation in areas already congested with existing duct bank, piping, cathodic protection and electrical grounding. This caused damage to the installed commodities requiring repair and replacement. The installation of additional duct bank was also affected by congestion. In some cases, concrete had to be removed to allow routing of new duct bank installation.

The Commission determines that Staff's recommended man-hours in the outside area are reasonable. All design changes included as part of an ECN have been allowed. The Commission further concludes that it was reasonable to disallow inadequately explained man-hours in the civil/structural and electrical categories since they appear to be related to late design, causing improper job sequencing, rework and congestion.

b. <u>Civil</u>

The civil category includes the pouring of concrete which in turn includes formwork, rebar and embeds, pouring, finishing of cement, and removal and cleaning of forms. Expended man-hours in this category is 4,782,886. The number of man-hours contained in the definitive estimate is 2,253,498. Staff recommends that 2,708,041 be included.

The man-hour overruns in this category are a result of DIC's failure to achieve the unit rates in the definitive estimate. UE enumerates the following reasons for inability to achieve the definitive estimate unit rates:

1. NRC delays
2. Design changes

3. Increased design density

4. Out of sequence placement

5. Size of pour.

NCR delays refer to nonconformance reports which are issued when a condition is detected that violates overall design criteria. Staff's review of the civil NCRs reveal that the predominant cause was design or detailing error. Because of detailing errors in many instances rebar could not be placed according to drawings. The record reflects that adequate review of the drawings was not accomplished before construction.

Detailing errors and design changes were major impediments to progress in the civil area. Civil work was affected by the design changes identified as necessary as field work proceeded. UE's explanation states that design changes affecting concrete activities were related to analyses and revisions in electrical and mechanical systems design. For example, a change in piping design could require relocation of embedded sleeves prior to concrete placement and movement of reinforcing steel would be necessary to accommodate the embedded sleeve. UE did not quantify the effects of such design changes nor did it track added man-hours associated with such changes. Many of these problems appear to be related to premature mobilization of DIC on the project prior to the sufficient completion of design. As noted in the preceding section, DIC was informing UE that the design was incomplete in August of 1977, and suggested that the construction pace be restricted.

UE also states that density of rebar and embeds increased over previous Bechtel nuclear projects. This increased density creates a greater level of difficulty in concrete placement and replacing rebars and embeds without interferences.

Bechtel did increase containment size and strength over the original Bechtel concept which may account for some of the tardiness of design. Staff witness Renken concedes that this resulted in increased design. However, Mr. Renken doubled unit rates for rebar installation and concrete placement. This increase resulted in a 144,000 man-hours which does not fully explain the overruns in the civil area.

The sequence of concrete pours was not in accordance with the original SNUPPS concept of accessibility which requires that work be accomplished at a stage of construction that minimizes interferences. A number of auxiliary building walls were poured beneath slabs or walls already poured. This was generally due to design or delivery delays and was done to expedite construction of the slab or wall above. This led to NCR's for rebar placement and concrete repair.

Delays in construction scheduling due to late design and revision, including increasing bulk commodities, caused congestion, which decreased craft efficiency. Out of sequence work was scheduled to keep some work crews active.

Mr. Renken has concluded that small pours were necessary. This was caused by disruption of the optimum construction sequence which rendered large pours impossible because of congestion and interference.

Mr. Renken reviewed data related to civil unit rates. Based on this data, Mr. Renken concluded that civil unit rates for nuclear plants were not strongly correlated with date of construction. Nevertheless, Mr. Renken increased the unit rate for his recommendation to 24.80 mh/cy (man-hours per cubic yard) compared to 18.25 mh/cy contained in the definitive estimate.

Mr. Renken accepted ECNs related to increased quantities for calwells, embeds, concrete, form work and rebar. Mr. Renken also accepted ECNs related to field fabrication of rebar.

Staff's recommendation includes man-hours necessary to repair several large outer surface voids in the dome concrete caused by DIC's failure to adequately consolidate the concrete used for safety-related construction.

The Staff included post-pour embedded items (surface mounted plates) that were identified with regulatory changes as documented in UE witness Stone's testimony. All man-hours associated with other post-pour embeds were excluded from

Staff's recommendation since installation of embeds before concrete is poured is the more efficient method. The total number of surface mounted plates reached 19,574. Mr. Renken notes that only one-half this number of surface mounted plates were required at the Wolf Creek plant. Staff attributes this to incomplete design at Callaway.

The Commission determines that Staff's conclusions in the civil category are reasonable and therefore only Staff's recommended level of man-hours should be allowed.

c. Structural Steel

The as-built man-hours for structural steel are 1,140,983. Staff recommends an allowance of 524,800 man-hours. In addition to structural steel, this this category includes grating, platforms, handrail, metal decking, and other miscellaneous steel.

Mr. Renken accepted ECNs related to clip angles, as built quantities and changed unit rates for fuel building structural steel rates.

The SNUPPS design and work plan called for grating and handrail to be installed at an early phase of construction. These items were to serve in the place of scaffolding, planking and temporary handrail. The definitive estimate was based on a one-time installation. However, frequent moving and reinstallation of grating and handrail occurred to permit the moving and installation of plant equipment. The cost overrun is so great that it would cover such reinstallation four times. UE provided no quantifiable reason for the magnitude of the overrun. UE claims that handrail and grating saves scaffolding costs. However, the savings in scaffolding costs is not apparent given the severe overrun in that category.

Mr. Renken recommends 67,485 man-hours for these accounts which more than doubles the definitive estimate and corresponds to the projected charges to these accounts at the Wolf Creek plant.

Sheathing is the steel which forms a network with tendons to contribute to containment strength. Although sheathing was greatly overrun, Mr. Renken recommended the as-built total be accepted based on UE's explanation that SNUPPS' containment is larger and stronger than earlier plants. Therefore, tendons are closer together and congestion of rebar is greater than expected. As a result, interferences were encountered between sheathing, rebar and embeds. If restrictions in the sheaths formed after pour, concrete had to be chipped out, the sheath repaired and the void patched.

Miscellaneous steel was greatly overrun. UE attributes this overrun primarily to late changes to supports attached to the steel and the related addition of seismic stiffeners. Data requests supplied by UE state that absent seismic stiffeners, man-hours for miscellaneous steel compared favorably with the definitive estimate. Based on this explanation, Mr. Renken limited his recommendation for miscellaneous steel to the definitive estimate.

UE prepared an ECN to estimate the effect of seismic stiffeners. Seismic stiffeners consisted mainly of steel plates installed to protect against possible effects of an earthquake. Seismic stiffeners were late additions to design and were installed at great cost after completion of bulk and structural steel. NRC requirements regarding seismic design were issued in 1976 in Regulatory Guide 1.92. In Mr. Renken's opinion SNUPPS design should have incorporated seismic requirements earlier. The record reflects that the installation of seismic stiffeners was still occurring in 1983. To permit the installation of some of the stiffeners, fireproofing that had already been sprayed on structural steel had to be chipped off. UE's ECN estimates work related to seismic stiffeners at 145,266 man-hours for 45 tons versus 167,232 man-hours for 9500 tons of structural steel in the definitive estimate. Mr. Renken does not include additional man-hours related to seismic stiffeners in his recommendation.

UE attempted to quantify man-hours expended in miscellaneous steel caused by late design. Additional man-hours due to late design almost equal the amount originally estimated. Mr. Renken does not include these additional man-hours in his recommendation.

Staff included in its recommendation an increase for shear stud unit rates because of less favorable construction conditions than were assumed in the definitive estimate. In addition, Mr. Renken included the man-hours related to reinspecting and reinstalling approximately 110,000 structural steel bolts. This work was improperly performed due to poor supervision and craft inexperience. In Mr. Renken's opinion UE could not have anticipated DIC's poor performance in this area.

Unit rates at Callaway for structural steel were 38.7 mh/ton. This was about the average as contained in a company-provided 13 plant study. Staff also compared structural steel unit rates with other plants. One study of 16 plants produced a mean of 33.2 mh/ton. A study of 12 plants produced a mean of 29.5 mh/ton. Another study of 51 plants showed a mean of 26.1 mh/ton. Mr. Renken recommends a civil unit rate of 34.35 mh/ton.

The Commission determines that Staff's recommended man-hours in the structural steel category are reasonable. Staff has increased unit rates in this category, has allowed rework in the structural steel bolt area and has given recognition to interferences in the sheathing area. Staff has properly excluded areas that appear to be related to late design resulting in inefficiencies.

d. Finishes

Staff recommends 179,764 man-hours in the finishes category. This category includes painting, concrete masonry walls, door, hatches and louvers, surface repair and coating of walls and floors, wallboard, ceilings, benches, lockers and other minor activities.

UE's analysis supplied to Staff in the finishes category states that concrete masonry walls (concrete block walls) were originally estimated as partition walls and nonseismic reinforced walls in the auxiliary and control buildings.

In 1979, the NRC issued information notice 79-78 describing possible structural inadequacies of concrete block walls. In 1980, the NRC issued Bulletin No. 80-11 describing seismic deficiencies in Bechtel design concrete walls at the Trojan Nuclear Plant.

UE's analysis supplied to the Staff further states that in 1979 Bechtel reclassified masonry walls in the auxiliary and control building as seismic category 1, II/I or II over I design. UE's analysis states that this design classification had a major impact on the concrete masonry wall installation.

II over I refers to NRC seismic requirements. Regulatory Guide 1.29 of 1973 prescribed that safety-related equipment must be designed to withstand a safe shutdown earthquake. This equipment was designated seismic category I. In August of 1973, a revision to Regulatory Guide 1.29 applied seismic requirements to nonsafety-related equipment located near or over safety-related equipment. Hence, the term II over I. In 1976, Regulatory Guide 1.92 provided additional guidance related to methods for measuring stresses.

Concrete block walls proved to be difficult to install and were constructed much less efficiently than poured walls in the power block. Mr. Renken compared the man-hours related to replacing the reworked concrete block walls with poured concrete walls of equal thickness and density of rebar. Staff calculated 71,681 man-hours for poured, reinforced concrete walls compared with 167,512 man-hours for the reworked concrete block walls.

UE's witness Schukai in his rebuttal testimony contends that Mr. Renken incorrectly concludes that concrete block walls in the control and auxiliary building were changed to seismic classification because of NRC Bulletin 80-11 and that Bechtel revamped SNUPPS' masonry wall design as a result of an error at another power plant.

Mr. Schukai maintains that seismic classification of concrete walls was established prior to issuance of design for construction. Thus, according to Mr. Schukai, when the time came to construct the walls, seismic design criteria had been incorporated and several nonseismic walls were changed to seismic classification rendering the walls more difficult to install than the originally designed nonseismic walls.

UE witness Stone also addresses concrete masonry walls stating that the design for concrete block walls was not modified because of the NRC Bulletin 80-11. Mr. Stone states that Bechtel's design complied with seismic requirements. Apparently it is Mr. Stone's contention that the concrete block wall situation described by Mr. Renken was caused by design evolution. Mr. Stone describes the situation as follows: the definitive estimate was based on layout drawings showing certain walls as block rather than poured, since design had not progressed enough to evaluate block walls for seismic requirements. In 1978, structural analysis began and 31 walls were changed from block walls to poured walls. In 1979, drawings were issued to identify which block walls were nonsafety related.

The evidence shows that NRC seismic requirements related to the walls in question have been in existence since 1973. Thus, whether the reworked concrete block walls were a result of the NRC's 1979 information notice or design evolution, the design was released late requiring expensive modification to concrete block walls. Accordingly, the Commission determines that the Staff's recommended man-hours related to concrete walls are reasonable.

The definitive estimate for doors, hatches and louvers shows 2,090 man-hours. The as-built amount was 42,075 man-hours. Staff included 5,502 man-hours for certain heavy doors in the turbine building which were not included in the definitive estimate. In addition, Staff reestimated water-tight doors in the auxiliary building and added 2844 man-hours to this category. UE was unable to supply a plausible explanation for the remainder of the extensive overrun. Therefore, Staff made no further adjustments to man-hours in this category.

Staff did not include any recommendations for miscellaneous finishes in excess of the definitive estimate. Some accounts were affected by late design while others were not estimated in a definitive estimate or in an ECN.

Having reviewed the evidence presented in the finishes category, the Commission concludes that Staff's recommended level of man-hours is reasonable.

e. Mechanical Equipment

Staff recommends 942,003 man-hours in the mechanical equipment category. This compares with the as-built level of 1,052,826 man-hours. The mechanical equipment includes the NSSS, major cranes, condenser, pumps, tanks, compressors, heat exchanges, and other miscellaneous mechanical equipment.

The installation of the condenser incurred a 765,050 man-hour overrun. The construction sequence for this item is as follows: the turbine pedestal would be constructed, then the condenser erected within the pedestal legs. The table top would then be poured. Meanwhile, construction of the turbine building was to be underway, including the pouring of the slab that formed the operating floor of the turbine building. The operating floor is designed with a large opening in the center to allow room for the turbine pedestal table to protrude through the opening of the floor.

Because of a deficiency in Bechtel design, the condenser sections were too large to lower through the opening in the turbine building floor. Large sections of the slab had to be chipped away to provide clearance. Man-hours for chipping were charged to concrete but delays and sequencing problems contributed to the condenser installation costs. Staff excludes the man-hour overrun related to the condenser.

Staff recommends 28,570 man-hours for major crane erection. The as-built man-hours for this category is 60,424 man-hours. UE's explanation enumerated a series of routine construction problems but nothing which would account for the 100 percent overrun. Mr. Renken compared Wolf Creek experience and determined that cranes were expected to be accomplished at the definitive estimate man-hour level. Therefore, Staff recommends the definitive estimate amount.

Other process equipment covers the balance of the plant mechanical equipment not included in the condenser, NSSS or major crane classification. UE was unable to quantify the cause of these overruns. Staff witness Renken compiled a list of items requiring installation efforts clearly beyond the scope of the definitive estimate. These estimates were made based on an analysis of the installation of identical equipment at Wolf Creek. Staff has added these estimates to the definitive estimate for its recommendation.

The Commission concludes that Staff's recommendations in the mechanical equipment category are reasonable and should be adopted.

f. Instrumentation

Staff recommends 336,689 man-hours in this category compared with the as-built total of 374,036. This category covers installation of over 3,800 instruments used to monitor operation of the plant, including gauges, transducers, valves, regulators, as well as two tubing hangers and stands for the instruments.

In this category, Staff recommends approximately 50 percent for scope increases for instrumentation extra work documented in UE's ECN. Staff included this amount which relates to rework necessary to replace instruments received in a defective condition from the vendor. The other 50 percent of increased scope was due to design changes which Staff has disallowed.

The remaining portion of the overrun that was not quantified by UE was attributed by UE to the ASME code, vendor delays and deficiencies, construction tolerances, design evolution and implementation of the Quasi/Q program. Staff accepted increased unit rates for the Quasi/Q program but rejected UE's other explanations as they were either attributable to late design or were not quantified.

The Commission concludes that Staff's recommendations in the instrumentation category are reasonable and should be adopted.

g. Hangers

902,141 man-hours attributable to hangers were included in the definitive estimate while 2,328,358 man-hours were expended. Hangers support the plant piping.

The number of hangers changed as compared to the definitive estimate and were included in Staff's recommendation. In addition, the as-built unit rates increased over the definitive estimate unit rates.

Staff increased man-hours in this category believed to be caused by subsection NF of the ASME code. This increase was based on a Wolf Creek study. Staff also included increases attributable to Quasi/Q programs.

Staff concluded that design evolution was a major cause of the overrun. Because of design evolution in other areas, rework and congestion occurred which necessitated that hangers be assembled in the field. In addition, design evolution caused hanger shortages involving vendor-supplied hangers. Bechtel was requested to design changes to hangers to allow site fabrication. UE's ECNs identify 1,500 hangers which were installed and later torn down. Of the 1,500 hangers, 908 were nonsafety related. UE documents reveal that 50 to 75 percent of increases in quantities of hangers which were still occurring in early 1982 were due to design changes. Therefore, hanger design was simply not sufficiently complete to support hanger construction.

Staff increased the number of man-hours to install hangers to reflect the fact that the hanger design for SNUPPS was more complex than for earlier plans. Since UE did not quantify this effect Staff's recommended increase is based on a study at the Wolf Creek plant.

In order to maintain schedule, UE used temporary hangers and temporary snubbers. The programs were included in the Staff's recommendation.

Staff documents a near chaotic situation with respect to the installation of hangers. The Commission concludes that Staff has included all additional man-hours for hanger installation which were adequately explained and were not related to late design.

h. Piping

Piping includes man-hours required to install and weld plant piping. The category also includes flushing and hydro-testing of the pipe and whip restraints. Piping is classified as safety related "Q" piping, nonsafety related or "non-Q" piping and "Quasi/Q" piping which must meet all augmented quality standards. Whip restraints are devices which restrain a pipe from damaging surrounding structures or components if the pipe should break.

Staff has included in its recommendation for piping installation and welding, increased man-hours related to fire protection, increased quantities, and increased welding related to quality emphasis. Staff excluded 194,313 man-hours contained in a UE ECN estimate which quantifies man-hours associated with rework necessary to incorporate design changes in already installed pipe.

Staff included only the definitive estimate amount for flushing and hydro-testing updated for increased footage of pipe. Staff has rejected UE's explanation for overruns in this area. UE maintains sampling stations were not included in the definitive estimate. However, regulations required sampling any time flushing occurs and UE states that the regulations were used as a reference in the definitive estimate. UE's other reasons relate to increased inspection and soaking and recirculation requirements.

The Commission accepts Staff's conclusion that these reasons do not provide a credible explanation of this overrun. Staff observed what appeared to be over-manning of craft support of flushing and hydro-testing.

The pipe whip restraints category was greatly overrun. 182,781 man-hours were expended compared to an estimate of 52,240 man-hours. Staff adjusted for as-built quantities. However, Staff rejected 56,525 extra work man-hours estimated in a UE ECN which was attributed to design change. Late design and design change of pipe whip restraints resulted in site fabrication, field interference and congestion.

The Commission determines that Staff's man-hour recommendation in the piping category is reasonable and should be adopted.

i. Electrical

The electrical category relates to conduit, cable trays, lighting, wire, cable, switches, circuit breakers, other electrical apparatus that carry electrical energy to and from the plant, mechanical equipment as well as all wiring interconnecting plant controls and monitors.

Electrical man-hours expended by UE were 3,784,625. The definitive estimate amount was 1,521,752.

UE provided the following explanations for increased electrical man-hours which were not quantified in ECNs: quality; detailed design; and design evolution causing retrofit, rework and inefficiency. Staff concluded that quality control affects indirect and not direct labor. Staff concedes that the design of electrical installation was detailed because of standardization. Therefore, less latitude in locating the installation is permitted. It is Staff's position that detailed design should reduce interference-caused rework. Although installation of conduit prior to installation of hangers could cause some interference, this could be prevented by proper construction sequence.

Staff believes that UE's third reason, design evolution, is the major cause of the overrun. A significant quantity of man-hours were expended modifying or reworking electrical installation because of design changes. Design changes which required additional pipe whip restraints and surface mounted plates caused removal and relocation of electrical raceway. Post-pour anchor bolts and core drills often damaged embedded conduit requiring installation of exposed conduit to replace the damaged conduit. In addition, delays in construction due to design changes caused congestion and deviation from the original SNUPPS concept of craft progression. This in turn caused overtime in shift work to alleviate congestion. The effect of II/I criteria on electrical installation in the auxiliary and control buildings reached the field in October of 1981. It has been established in this record that II/I criteria were formalized in NRC Regulatory Guide 1.29 promulgated in February, 1976.

UE documents show that in 1980, conduit installation in the turbine building was being limited by Bechtel design releases. The turbine building is largely exempt from NRC regulations. Nevertheless, this problem was still in existence in 1981.

Based on the foregoing, the Commission determines that Staff's recommendations in the electrical area are reasonable and should be adopted.

j. ESWS

Data on the construction of the essential service water system (ESWS) was requested by Staff in November of 1982. UE provided the data in the true-up reconciliation of August 5, 1984, but only as man-hour totals with no supporting explanation. Staff checked and confirmed the ECNs and ETNs. Thus, Staff recommends a definitive estimate allowance plus audited scope changes contained in the ECNs and ETNs. Staff recommends no other adjustments.

The Commission determines that Staff's recommendations regarding ESWS are reasonable since they are based on ECNs provided by UE and UE provided no other explanation.

2. Scaffolding Costs

Although scaffolding costs were addressed in Mr. Renken's testimony related to direct labor man-hour adjustments, these costs are indirect costs. Scaffolding costs were estimated in the definitive estimate using a percentage of 4.3 percent total direct man-hours except for piping scaffolding which was estimated as a direct man-hour cost of six percent of piping man-hours. Staff proposes an $8,343,602 disallowance.

Mr. Renken concluded that the definitive estimate percentage accurately predicted the scaffolding scope except for the effects of late design. The design gap between pipe and hanger installation affected scaffolding. It was assumed in the definitive estimate that installation of piping and hangers would be close enough in time to permit the use of the same scaffolding. The SNUPPS work plan assumed that hanger installation would precede pipe installation. As it turned out, piping was installed using temporary hangers and permanent hangers were installed months later. During the interim, scaffolding was removed and replaced for permanent hanger installation. In some cases scaffolding was removed and replaced three or more times to permit design change rework. Piping scaffolding required over 20 percent of piping man-hours in contrast to the six percent definitive estimate.

Staff has reestimated the scaffolding based on Staff's recommended direct total man-hours and piping man-hours. Staff also added an allowance for scaffolding which DIC installed for subcontractor support. Staff's total recommended man-hour level for scaffolding is 766,287.

Since scaffolding overruns are attributable to late design in the hanger area, the Commission concludes that the Staff's recommended man-hour level for scaffolding costs is reasonable and should be adopted.

3. Start-up Costs

Staff recommends disallowances of $17,043,000 in the area of start-up operations. These disallowances relate to Staff's contention that start-up operations were prematurely mobilized and that UE and its current partners in SNUPPS failed to fully develop and utilize the SNUPPS concept in the area of start-up.

a. Premature Mobilization of Start-up

Staff recommends a $16,417,000 rate base disallowance associated with premature mobilization of the start-up organization.

Start-up is the period in the construction project where the focus changes from bulk construction activities to system completion and preoperational testing.

Start-up personnel are responsible for testing and starting up the plant prior to fuel load.

UE began hiring consultants for start-up planning in 1979 and commenced start-up operations in 1980. In August of 1980, Callaway was reported to be 70 percent complete. In fact, the plant was 40 percent complete. Evidence in the record suggests 70 percent is an accepted standard for the commencement of start-up activities. Clearly, 40 percent completion is too soon to concentrate on system completion and testing. Accordingly, the Commission concludes that the start-up effort at Callaway commenced prematurely.

Given premature start-up, the relevant question to be asked is: "Was premature mobilization beyond UE's control?" Staff alleges that premature start-up was a direct result of UE's failure to coordinate construction completion with start-up. This is a special case of UE's overall failure to coordinate construction discussed in Section II.D. above.

As discussed in Section II.D. above, UE did not know the status of the project in terms of cost or completion until it successfully integrated the project in 1983. With respect to the start-up issue, the record reflects that DIC's quantity tracking system (QTS) was installed at Callaway in 1977 with the last system installed in June, 1979. This system tracked electrical and mechanical components. Civil quantities were manually tracked. The QTS system and other tracking systems were not fully utilized.

In June of 1979, it was recognized by UE's manager of nuclear construction that discrepancies existed in quantities installed reported in the QTS and the cost report. Also, in June of 1979, UE's schedule engineer stated that the state of the tracking system would be virtually useless to the start-up effort.

Based on the above, UE had notice in 1979 that information regarding plant completion status was unreliable. UE, nevertheless, commenced start-up in August of 1980, without a reliable estimate of the status of the project. It was not until

July of 1981, that UE conducted walk downs to establish the extent of work to be completed.

The Commission notes that UE's MAC report authored by Mr. Traylor revealed that UE failed to integrate system completion and start-up. The record establishes that UE was the overall integrator of the project and thus, it was UE's responsibility to assure that it was relying on accurate information regarding the status of the project. A consequence of the failure to properly integrate construction, completion and start-up is manifested by the premature mobilization of the start-up team. The Commission determines that this premature mobilization of start-up was imprudent.

The definitive estimate did not contemplate the use of mostly outside consultants for the start-up organization. Out of a total of 371 start-up personnel at peak, 300 persons represented one of the following consulting groups: Westinghouse; System Coordination, Inc., (SCI); Jebcon and Matsco. Because of the change in scope of start-up operations and personnel, Staff did not use the definitive estimate as a starting point to determine a reasonable level of start-up costs. Instead, Staff used the 1981 start-up budget as a starting point. This budget was the first to incorporate expenses for the on-board consultants.

Using the 1981 budget, Staff increased the man days by 18.2 percent to cover increases in scope; increased mandays by 25 percent to provide for contingency; increased the number of mandays by a 10 percent overtime allowance; increased start-up expense to allow for per diem using $1,000 per month for scheduling and controls, start-up engineers and start-up technicians; decreased the number of mandays by 8558 for Union Electric Nuclear Organization (UENO) I&C technicians; and increased the number of mandays relating to the start-up planning phase prior to August of 1980, giving Staff a total start-up cost figure of $57,556,779.

The Commission rejects UE's arguments that all start-up costs were prudently incurred even if start-up operation commenced too early. Apparently UE's arguments are based on successful duration between fuel load and commercial operation. There is no evidence in the record to support the proposition that the duration of the schedule from fuel load to commercial operation is a result of the timing of start-up operations. Neither does the fact that start-up consultants performed tasks in other areas of construction support the total costs related to premature start-up. UE has not proven that placing highly priced consultants in other areas of construction is cost effective.

The Commission determines that the Staff's adjustment related to premature start-up is reasonable and that it is appropriate to use the 1981 budget. This budget was prepared with the assistance of highly experienced start-up consultants and therefore a reasonable projection of start-up costs should be reflected in the start-up budget. In addition, Staff adjusted the budget for scope changes and utilized reasonable levels for overtime and contingency.

b. Failure to Utilize SNUPPS

Staff recommends a disallowance of $626,000 in start-up costs that Staff maintains should have been shared with other SNUPPS members.

Staff argues that $300,300 should be disallowed because UE did not share the cost associated with the set point document with Kansas Gas and Electric Company. The record reflects that UE attempted to persuade Kansas Gas and Electric Company to share in the development of this document. KG&E declined this offer since it had already commenced developing its own document and expected to complete the document prior to UE completion.

The Commission determines that Staff's disallowance related to the sharing of the set point document should be rejected since KG&E declined to participate. There is no evidence that UE was negligent by not securing KG&E participation. Clearly, UE could not force KG&E to do so.

Staff also proposes a disallowance of $323,000 associated with the test program coordination group. This adjustment is related to the rewrite and review of component tests and preoperational procedures, to increase detail in factory and actual plant operational and testing logic and to include specific reference to the associated technical manuals.

The evidence establishes that this rewrite and review was necessary to make the procedure site specific. UE contends that the use of the same start-up team would not be practical at Callaway and Wolf Creek; that common training facilities had been found to be less than desirable; that it is now the industry standard to have training facilities at each site; and that spare parts pooling and start-up and operational feedback is in fact ongoing between Callaway and Wolf Creek.

4. Schedule

Staff proposes to allow AFUDC only on the duration of the construction schedule associated with Staff's recommended level of man-hours. This results in a $88,778,000 recommended disallowance. Staff's schedule is also used for adjustments related to safety meetings and indirect costs discussed in section III.A.10 below.

Staff witness Renken has attempted to calculate the effect on the Callaway schedule if Staff's disallowed man-hours had not been worked. Staff states that this effect cannot be precisely quantified. Thus, Staff's calculation represents an approximation.

Staff calculates the rate of completion of the as-built plant as a percentage per month. This rate of completion data is then applied against the as-built man-hours at completion. This value, in units of man-hours per month, is termed a work-off rate. By calculating work-off rates for the Staff recommended man-hours, at various percentages of construction completion, Staff converted completion percentages to calendar months. Staff counted backwards from the June, 1984 fuel load date. The work-off rates were calculated from the as-built completion curve by dividing this curve into six segments and calculating a regression line for each segment. The correlation factor for each regression line was greater than .985. Staff's calculation produces a schedule duration of 80.5 months.

UE argues that Staff's schedule contains no construction logic and does not follow the critical path. In addition, UE argues that Staff's schedule does not comport with reality since Callaway's schedule duration was better than the industry average.

Contrary to UE's assertion, Staff's schedule contains the actual as-built construction logic used at the plant coupled with conservative manpower loadings. Also, it appears that the majority of Staff's man-hours are on the critical path.

Further, it is not readily apparent that industry average data demonstrate that Staff's schedule calculation is unreasonable or not within the bounds of reality. The St. Lucie II plant in Florida is one example of a plant where design was sufficiently ahead of construction when construction commenced. St. Lucie II was completed in 72 months. Nevertheless, Staff's schedule is not an attempt to recommend a hypothetical preferred schedule or to fix an optimum schedule duration.

The Commission determines that Staff's schedule should be approved. In approving Staff's schedule, the Commission is recognizing that an adjustment must be made to include AFUDC and indirect costs associated with delay caused by UE's failure to properly integrate the project. In the Commission's opinion, Staff's schedule adjustment allows a reasonable estimate of these costs.

5. Overtime

In 1981 UE determined that the completion of the construction of Callaway as scheduled was in jeopardy. One of UE's responses to the situation was to substantially increase the use of overtime to attempt to meet the existing schedule or reduce any scheduling overrun. The following charts show the increase of overtime after 1981 (Exhibit C-99A, p. 6-72).

Year	Regular Hours	Overtime Hours
Cumulative to 12/77	2,372,340	133,925
1978	3,575,360	240,337
1979	4,685,536	161,490
1980	4,386,776	82,260
1981	4,307,867	193,586
1982	4,247,690	856,854
1983	3,497,948	1,036,950
To May 1984	1,174,909	657,349
	28,248,426	3,362,751

A significant growth in overtime is identified within the period from March 30, 1982 to May 29, 1984. During this period of time, overtime for all crafts averaged 30.9% of regular hours or 12.4 hours per man per week. The following identifies premium hours as a percentage of regular hours for all craft labor.

Year	Percent Premium To Regular Hours	Weekly Average Number Of Overtime Hours
Cumulative to 12/77	5.6%	2.2
1978	6.7	2.7
1979	3.4	1.4
1980	1.9	.8
1981	4.5	1.8
1982	20.2	8.1
1983	29.6	11.8
To May 1984	55.9	22.4
Average for job	11.9%	4.8

Staff proposed in this case a disallowance of $62,288,260 ($57,438,000 Missouri jurisdiction) related to nonproductive overtime and straight time which Staff asserts resulted from the increased use of overtime by UE. The proposed disallowances include gross pay, fringes, burden and workmen's compensation. Staff's disallowance is based upon an analysis done of UE's overtime performed by O'Brien-Kreitzberg & Associates, Inc. (OKA) and sponsored by Staff witness O'Brien. O'Brien developed his concepts of overtime from several sources, but relied primarily on the book Methods Improvement For Construction Managers (1972, McGraw-Hill), written by Henry W. Parker and Clarkson H. Oglesby, and on the Business Round Table report "Scheduled Overtime Effect On Construction Projects".

Based upon a chart presented in the Business Round Table report, OKA developed a program to determine how much overtime used by UE was nonproductive. The nonproductive time results from work fatigue, with the symptoms being absenteeism, injury increase and impact on other projects in the area, caused by workers being required to work several weeks in succession with overtime. Although there was a disagreement between UE and Staff over what to call UE's overtime, there is no real dispute that UE used overtime on an extended basis over several years. This use of extended overtime over a period of years brings UE's use of overtime within the parameters of the analysis done in the Business Round Table report.

OKA developed a schedule impact based upon its analysis. OKA determined the nonproductive straight time and overtime extended UE's schedule a maximum of 4.6 weeks. OKA concluded that by using extended overtime UE, in fact, reduced productivity below what would be accomplished during a 40-hour week, and this results in OKA's schedule adjustment.

O'Brien based his analysis of overtime on several criteria. He adopted a standard 40-hour work week which he later modified because of scheduled vacations. He used productivity rates developed from the Business Round Table report. The Business Round Table report presents productivity curves for 50-hour and 60-hour work weeks. O'Brien interpolated between the 50- and 60-hour curves and between 40 hours a week and the 50-hour curve to come up with productivity figures. O'Brien then determined that he should begin his analysis of productivity based upon 45-hour work weeks. These productivity curves are to show the inefficiency associated with working those numbers of overtime hours. O'Brien did not impose a penalty for overtime until a worker passed 45 hours. O'Brien chose a recovery period of at least two 40-hour weeks before work productivity would return to normal. O'Brien decided upon the two-week recovery period on his own judgment, since the Business Round Table report is silent on this factor. In utilizing the productivity percentages developed by the curves, O'Brien took a 12-week segment for which overtime was worked and developed the average amount of overtime per week, and used that figure in his productivity table to get the percentages which show nonproductive time for the weeks.

UE attacks the OKA study on three bases: (1) that the OKA calculations are not consistent with the literature on which they are based; (2) that overtime data from Callaway was misapplied; and (3) that assuming OKA is correct about lost productivity, there was no offset for schedule improvement due to overtime.

The Commission does not feel it is necessary to address all of UE's specific criticisms of the OKA study. The Commission concurs in UE's criticism that the OKA study was not supported by the literature. The Commission echoes some of UE's criticisms in reaching that conclusion.

The evidence indicated that O'Brien had never previously performed an overtime productivity study. O'Brien ostensibly used the Business Round Table report as the basis establishing the criteria for his study. O'Brien, though, developed additional criteria not in the Business Round Table report and for which he did not have independent justification or support. The Business Round Table report had graphs for 50- and 60-hour work weeks. The report does not show a productivity curve for a 45-hour work week. There is no support for the 45-hour work week productivity figures prepared by OKA from the Business Round Table report. OKA used a two-week recovery period before productivity returned to normal. There is no evidence to support the use of this criterion. O'Brien decided no recovery was accomplished even if his analysis showed only a 41-hour work week. The Commission does not feel that this is a reasonable application of the Business Round Table report and finds this criterion is not justified by the evidence in the record. O'Brien averaged overtime over 12-week segments to develop average overtimes per week. Although the use of an average may be appropriate, O'Brien presented insufficient justification and evidence to support his decision to use a 12-week period to find his average.

UE had criticisms of the OKA study with regard to interpreting the Callaway data. Most of these criticisms related to the use of the 40-hour work week where UE says that its employees did not work 40-hour work weeks because of vacations, sick leave and other times off. O'Brien made certain adjustments based upon UE's indication that vacation days were allowed each employee. The other criticisms will not be addressed, since the Commission has found that the OKA study is not reliable based upon the criteria utilized to develop its analysis.

UE also criticizes OKA for not interpreting the data to determine any offset for time gained in construction by the use of overtime. The Commission finds that this is not Staff's responsibility. If UE wished to present evidence to offset any disallowance generated by an acceptable study, it could have produced that evidence and presented it at the hearing.

6. OKA Adjustment

OKA has recommended an "order of magnitude" adjustment associated with UE's failure to integrate design and construction. This adjustment is $522,000,000 using OKA recommended man-hours and $462,000,000 using Mr. Renken's recommended man-hours. This adjustment is offered as an alternative estimate of all costs associated with Staff's direct man-hours, overhead, overtime, and AFUDC adjustments.

Since the Commission has accepted the reasonableness of Staff's adjustments, except for overtime, the Commission concludes that the OKA adjustment should be rejected. The two adjustments are mutually exclusive and the Renken proposal was cogent and well documented.

7. SNUPPS/NPI Management Of Design Disallowances

a. Disallowance Of Twelve C/EWs

Staff has recommended disallowance of approximately $8.2 million of costs associated with 12 change/extra work (C/EW) orders submitted by Bechtel. The 12 C/EWs were 12 of those C/EWs reviewed by Touche Ross in its report. Touche Ross reviewed 54 of the C/EWs submitted by Bechtel to NPI for review, which accounted for approximately 50 percent of the additional man-hours budgeted by Bechtel. Touche Ross determined that the 12 C/EWs were not supported by sufficient documentation and that NPI did not review them to determine if the 12 were cost overruns of the definitive estimate or were changes or extra work.

Touche Ross reviewed NPI's method of controlling Bechtel's requests for design changes and the man-hours associated with those design changes. Touche Ross focused primarily on the formal system adopted by Bechtel for reporting additional costs and design changes to NPI and SNUPPS. Any work which was beyond the original scope as set out in the definitive estimate had to be approved by SNUPPS/NPI. The change/extra work method was developed by Bechtel in 1976 and incorporated the terminology used in the Bechtel contract. The forms were called change/extra work orders or C/EWs.

The contract with Bechtel is a fixed fee plus costs contract. This means Bechtel will be reimbursed for all reasonable costs associated with the contract, but will not receive an additional fee except as specified in the contract. The two categories for additional work where Bechtel might seek an increased fee are changes or extra work. "Changes" are modifications or additions to the project required by regulatory requirements. For any substantial changes Bechtel may request an increased fee. "Extra work" are additional requirements placed on Bechtel by the utility which were not within the general scope of the contract. If Bechtel performs any extra work, the parties, according to the contract, were to agree upon any additional compensation Bechtel was to receive.

Since 1976 Bechtel has submitted 1,605 C/EWs to NPI, totaling approximately 3,328,213 man-hours. The definitive estimate projected 4,230,000 man-hours for design. From these two amounts it can be seen that the C/EWs increased the design man-hours over 75 percent of the original projected man-hours. The substantial increase in man-hours had a significant impact on cost and schedule of work performed by Bechtel.

The report criticized NPI's review process of the C/EWs submitted by Bechtel. The report concludes the review process did not focus on whether the additional work was a change or extra work, but reviewed the work to determine whether it was needed. NPI thus did not adopt Bechtel's procedure for determining change and extra work, and NPI did not develop a procedure of its own.

UE witness Petrick admits this was the case. UE made a conscious decision not to adopt the C/EW format used by Bechtel and to make no determinations concerning whether additional work was a change or extra work. NPI never approved additional work as either change or extra work. A determination was not made apparently so Bechtel would have no claim for additional fees based upon those determinations.

The Touche Ross report by inference suggests that NPI did not approve the additional man-hours expended by Bechtel as reflected in the C/EWs. This was not the case. On cross-examination Petrick stated that all additional man-hours were approved by SNUPPS/NPI prior to Bechtel's performing the work. The NPI review of the C/EWs was merely to approve that the work needed to be done and to allow Bechtel to put the man-hours into its budget. The man-hours in the C/EWs were projected man-hours. NPI did not and has not reviewed the man-hours of each C/EW to see if Bechtel performed the work as projected or what man-hours were actually expended.

Touche Ross reviewed 54 C/EWs, which represented approximately 50 percent of the total man-hours expended for all C/EWs. Of these 54, there were 12 that Touche Ross felt were not properly reviewed by NPI. Staff's proposed adjustment in this case is based upon the costs associated with those 12 C/EWs. This issue was formed by Staff witness Werderitsch as follows:

> A. The issue that we have is really that, right now, the additional three-point-some man-hours and more specifically the 600,000 hours that we've identified in these 12 CEW's form the basis of a potential additional fee, that they fall within the definition and they have been tracked by Bechtel as changes or extra work and have been submitted to NPI, and they have not been resolved from that standpoint. And it was our basis that the ones we've identified, at least a good portion of them, can be thought or can be analyzed to be within the framework of the definitive estimate, and that the definitive estimate being based

on the technical scoped document as well as the agreement between the utility and Bechtel, that a certain portion of that work may be considered over the initial budget and not necessarily falling into the changes in extra work which could lead to additional fee requests. (Tr. 4427).

Werderitsch indicates the disallowance should be made because of the potential that Bechtel might seek additional fees for the work performed. Bechtel has made no such request. Staff in its brief requests the Commission to order an audit of all C/EWs' man-hours to determine if they are cost overruns or if the man-hours are justified. Staff asserts UE has paid Bechtel for this work and is passing these costs on to the ratepayers without justifying the expenditures.

The Commission cannot accept either Staff's disallowance or the request for an additional audit of all C/EWs. The disallowance is not justified since Bechtel has not yet requested increased fees for any of the 12 C/EWs. The Commission cannot justify an audit of all C/EWs without some indication the benefit would outweigh the cost and delay. Auditing the C/EWs will only increase the duration of the issues in this matter and prolong the uncertainty of the final impact of Callaway. The Commission finds an audit of the C/EWs is not justified.

b. Design Deficiencies

The contract between Bechtel and UE specifies that Bechtel's liability for work performed is limited to the correction of deficiencies which result from Bechtel's failure to perform in accordance with standards imposed by law upon professional engineers and architects. For those deficiencies Bechtel is responsible for the redesign man-hours and those costs should not be paid by UE. Petrick testified that UE was waiting until the completion of Bechtel's contract to determine whether to seek recovery of any additional amounts related to design deficiencies.

NPI kept only one formal list of design deficiencies. The list included 35 deficiencies reported to the NRC which were with regard to safety-related design. No formal list was kept of the nonsafety-related design deficiencies found by UE. Petrick testified that UE had informed Bechtel of certain design deficiencies which

UE had found, but that UE had elected not to act upon them at the time of the hearing.

Staff recommends an audit review of the intended disposition of the identified design deficiencies and a review of the process of identifying any additional deficiencies. The Commission is of the opinion Staff's request is justified. UE has chosen to delay seeking any recovery from Bechtel for design deficiencies until after Bechtel's work on the project is completed. This prevents the Commission, in this case, from reviewing UE's decisions and the ratepayers from receiving any current benefit of UE's potential future recovery. The Commission considers it UE's responsibility to seek recovery for all costs associated with design deficiencies for which Bechtel should not have been paid. The Commission will therefore order UE to provide Staff a complete list of all design deficiencies it has identified, both safety and nonsafety, a list of those design problems which UE would consider to be deficiencies, the costs associated with those design deficiencies listed, and a statement concerning UE's proposed action with regard to those deficiencies.

8. Budgeted Direct Craft And Overhead

At the time of the hearing, UE's cost for Callaway included $41,122,000 as budgeted craft and overhead costs not incurred as of fuel load. The Hearing Memorandum states that Staff agreed to true-up these costs at the true-up hearing.

At the true-up hearing the parties presented the Commission with a stipulation and agreement. With respect to budgeted direct craft and overhead costs not incurred as of fuel load, the true-up testimony indicates that the actual costs amount to $55,477,000. Staff audited overhead support and recommends that $18,434,000 be allowed. However, Staff was unable, because of time constraints, to audit the direct labor associated with start-up.

Staff and UE agree that the unaudited costs should not be included in rate base in this case, and that UE should be allowed to accrue AFUDC until such time as the approximate $17,000,000 in unaudited costs are addressed in the next rate case. Public Counsel concurs with this agreement.

The Commission concludes that $18,434,000 shall be allowed in this case and that the remainer of unaudited costs related to budgeted direct craft and overhead costs shall be allowed to accrue AFUDC until the costs are addressed in UE's next rate case.

9. Safety

This adjustment eliminates from the indirect cost codes certain man-hours and costs generated by safety meetings. Staff originally eliminated all safety meeting dollars from the indirect manual labor cost code. Staff modified its proposed disallowance based upon UE's evidence. Staff and UE agreed that based upon an acceptance of Staff witness Renken's schedule and associated man-hours, the disallowance would be $2,828,000.

UE contends the disallowance is not proper since safety meetings are associated with the actual manpower levels and since those were justified, the safety meetings were justified.

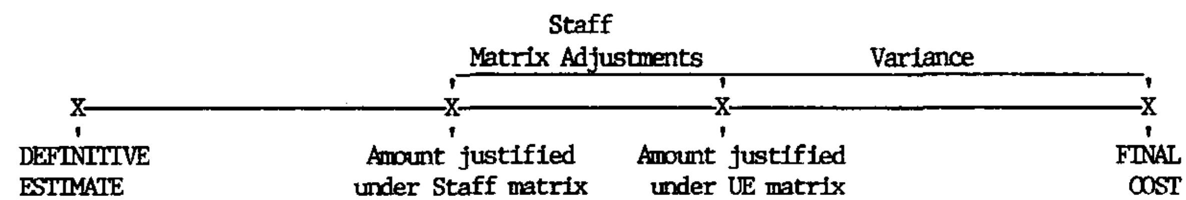
The Commission has already accepted Staff witness Renken's schedule and man-hour calculation, and believes it is only reasonable to disallow the safety meeting costs associated with the reduction in man-hours.

10. Indirect Costs

Indirect costs are those costs associated with indirect manual labor and indirect materials. Indirect manual labor means craft labor performed by DIC employees not actually performed on the physical plant. Indirect materials consist of materials and supplies necessary for the construction of the Callaway Plant but not considered part of the permanent plant structure. Staff has proposed certain disallowances with regard to both indirect manual labor and indirect materials.

To develop the amount of the disallowances proposed, Staff utilized a matrix format presented by UE in its reconciliation packages. The matrix relates indirect costs to schedule duration, man-hours, manpower levels and other variables of a construction project. Staff adopted UE's matrix as the best available method of comparing the costs projected in the definitive estimate with those of UE's 1983 forecast of Callaway investment. UE utilized the matrix by increasing the definitive estimate costs because of schedule duration and manpower adjustments, thus reducing the difference between the definitive estimate and the 1983 forecast.

Staff used the matrix in the same manner but used the calculations of Staff witnesses Renken and Winter for the schedule and manpower adjustments to the matrix. A simplified version of how Staff utilized the matrix is set out below. This chart is not drawn to scale and only serves as a model of what occurs (Exhibit C-248).



Using the above chart, it can be seen that Staff's adjustments to the matrix are less than UE's. This difference is shown as "Staff Matrix Adjustments". Staff has proposed adjustments based upon the difference between Staff's matrix adjustment and the final cost. Any variance between the "amount justified under UE matrix" and final cost was considered by Staff as unexplained and so was included in its proposed disallowance. The Commission has reviewed the matrix and its use by UE and Staff and finds it is a reasonable method upon which to compare the costs of the Callaway Plant.

UE stated in its Initial Brief - Part A that it had no objection to the matrix adjustments other than the inputs used by Staff. The Commission has adopted the inputs of Staff and so Staff's proposed adjustments in paragraphs 5 and 6 of the hearing memorandum involving indirect costs and indirect nonmanual labor costs are adopted. Paragraph 7 involving safety meetings is discussed earlier. The disallowance for paragraph 5 is $13,491,000 and for paragraph 6 is $12,071,000.

a. Indirect Manual Labor

i. Potable Water

Staff proposes a disallowance for the man-hours associated with the preparation and delivery of potable water to the construction crew working at Callaway. The amount proposed to be disallowed is based upon Staff's matrix and the actual labor rates.

The evidence indicates there were significant cost overruns in the cost code category for potable water beginning in 1979. Although UE reviewed the potable water distribution system two or three times a week, the system was not audited until 1983. In 1983 UE ordered an engineering study of the potable water distribution system. The initial report was made in May 1983, with a follow-up report in October 1983.

The purpose of the study as stated by the report is as follows: "Concerned at the cost of providing potable ice water, Industrial Engineering was instructed to determine: the number of ice water jugs currently provided; their location; how they are monitored and/or tended; operating costs; project responsibility for providing ice water as per labor contract agreement or OSHA standards; possible cost reductions."

The report then details what the existing conditions were and recommends improvements. The report concluded, first, that UE was providing ice water without specific OSHA or contractual obligation. The report concluded that there was a need for reorganization of delivery routes, better tracking of water jugs between shifts, duplication of water fountains and potable ice water jugs, reduced delivery in winter, reduction of manpower involved in making ice, reduction of overtime, and the possible purchase of ice from a private contractor.

The report made several recommendations based upon its conclusions. These recommendations resulted in improvements in delivery of the ice water and reduction in cost as evidenced by the follow-up report. New routes were developed and better control procedures were implemented.

Staff bases its proposed disallowance on the results of the engineering study. Staff proposes a disallowance of $1,309,000. This amount is based upon man-hours developed by the matrix, which is an overrun based upon Staff's schedule of 126,690 man-hours.

UE's witness Cole stated that the 1983 engineering study was conducted because of reduced manpower levels at the construction site. Manpower levels were down from a high in 1979. UE also contends Staff made no adjustment to the disallowance for any additional costs associated with increased monitoring. UE asserts it monitored the ice water distribution system two or three times a week and there is no suggestion this was not enough. This monitoring was conducted prior to the 1983 study, but no records were kept of the monitoring.

The Commission considers it UE's responsibility to ensure its operations are run efficiently and at reasonable cost. The issue of potable ice water distribution may sound inconsequential, but it is significant in total dollars. The 1983 engineering study found that the potable ice water distribution system was not functioning efficiently. UE made corrections based upon that study and cost savings were realized.

The Commission considers it unreasonable and imprudent for UE to have substantial overruns in cost code accounts and wait four years to determine the cause. The Commission is aware ice water is related to safety and the well-being of the workers, but there is no evidence the changes made because of the 1983 study caused any problems in those areas. The Commission finds that UE failed to properly ensure that its distribution system for potable ice water was efficient and the Commission therefore adopts Staff's proposed disallowance of $1,309,000.

ii. Temporary Power

Staff proposes an elimination from rate base of an amount associated with the category of temporary power. Staff bases its proposal on the original SNUPPS concept for use of temporary power at the Callaway Plant. The SNUPPS concept was to install a permanent power system early in the construction project, and this permanent system was to be used in lieu of temporary power.

UE was unable to install a permanent system as projected. This required the installation and use of an expanded temporary power system. Staff proposes to disallow from rate base the cost overruns as developed through the matrix for those costs between Staff's justified amount and the final cost. The reason for rejecting these costs is based upon the additional costs associated with the temporary fixtures of the temporary power system. Some of these costs occur because the temporary system would be exposed to more damage than the permanent system. This damage would occur because the lines and fixtures of the temporary system are exposed and not marked. The temporary system also must be moved to accommodate other construction work. More time was required for the installation and modification and removal of the temporary system as the need for power increased, and this increased the man-hours and material to install and move the temporary power system.

UE's response to this proposed disallowance was to contend that the installation and use of the permanent power system would have increased the cost for permanent power an amount comparable to the Staff's proposed disallowance for temporary power. UE, though, did not quantify this assertion. UE asserted this offset was obvious.

The Commission has previously noted the lack of coordination between what UE was projecting to happen at the Callaway construction project and what actually happened. Staff's proposed disallowance in this instance again reflects the failure of UE to anticipate and coordinate the construction as projected. The evidence shows that a temporary power system is inherently more costly than a permanent system, due mainly to its temporary nature. Installation of a permanent system occurs once; a temporary system is continually in flux and must be removed once a permanent system is installed. Based upon these considerations, the Commission finds Staff's proposed disallowance for temporary power is reasonable. The Commission cannot determine the amount of any offset that the cost of permanent power may have had without sufficient evidence. UE has presented no evidence from which to make an offset adjustment. The disallowance is $3,601,000.

b. Indirect Materials

i. Construction Equipment

This proposed disallowance by Staff is for costs associated with the Cost Code "Repair, Maintenance and Modification of Construction Equipment". The account includes the cost of servicing, maintaining and repairing construction equipment with a purchase price of over $2,000. This includes both job-owned and rental equipment and the parts, materials and labor involved for servicing or repair work.

Staff has proposed to disallow the costs associated with this cost code between the amount justified by Staff on the matrix and the final cost. Staff proposes this disallowance because (1) UE failed to have an effective audit program of its parts inventory from 1976 to the fall of 1980; (2) UE failed to adhere to procedures developed in 1982 for physical inventories; and (3) inadequate security.

Staff's evidence indicated that UE permitted persons requisitioning items to also pick those items up from the main warehouse. This prevented any accounting control because the person who might make an error in requisitioning was also the person who would pick up the part and therefore could cover up the error. Staff contended this was a more serious problem than anticipated when UE began construction, because of UE's substantial use of used equipment rather than new equipment. The use of used equipment increased the need for parts and repair.

In January 1982, UE developed separate inventory procedures for the equipment shop. Staff's evidence indicates these procedures were not followed. The procedures required a physical inventory of parts every three months and the resolution of any discrepancies. UE only inventoried the equipment shop when time permitted. Discrepancies between physical counts and records were not resolved as required by the procedures.

Staff's evidence indicated that physical counts were not conducted by persons independent of inventory control. This, again, was a failure to separate duties to ensure accountability. Only one complete audit was provided to Staff by UE. That audit indicated equipment was not properly marked, as well as the problems already indicated above.

Staff contended, finally, that UE's security was not adequate and this could have contributed to the cost overruns. Staff found that the equipment outside the equipment shop was not protected by a fence, and security was lacking for preventing theft of the equipment.

UE's response to this disallowance is, initially, that the Staff should have offset the cost codes with cost overruns against those that were less than the amount justified by Staff's use of the matrix. UE then asserts its procedures were adequate for the inventory control of the equipment shop and additional audits would have cost additional dollars. UE asserts the cost of additional audits would not have been justified by any savings that might have occurred. UE asserts that there were legitimate reasons for not spending money on audits every year. UE states the equipment shop was a minor operation early in construction and purchase orders were reviewed, which substituted for a formal audit. UE also denigrates Staff's requirement of an audit by pointing out the minor dollar value of discrepancies found in the 1983 audit.

UE asserts it increased its procedures in 1982 when the equipment shop increased in importance. UE states it had adequate control over its personnel, since those requisitioning and picking up orders were supervised and checked by purchasing personnel and warehouse personnel. UE states in addition that there was a project security fence with a guard to prevent removal of UE equipment, so no security fence was needed around the equipment stored at the equipment shed.

The Commission has considered the positions of UE and Staff with regard to this disallowance. The Commission believes that this is another example of UE's failure to properly prepare itself for the magnitude and requirements of building Callaway. The evidence is that UE obtained more used equipment than projected, thus increasing the need for parts and maintenance. This increased the importance of the equipment shop prior to 1982. UE did not implement procedures to adequately control its inventory in the equipment shop until 1982. Even when it adopted adequate procedures it did not follow them. The Commission finds there is sufficient evidence of inherent internal control weaknesses with regard to the equipment shop to support the disallowance proposed by Staff. The Commission does not believe an unrelated and unexplained reduction in costs in one cost code can be offset against an overrun in another cost code supported by competent and substantial evidence. The disallowance is $375,000.

ii. Potable Drinking Water Service

This proposed disallowance relates to Staff's proposed disallowance for the manual labor associated with potable drinking water. This disallowance is for the material in this cost code, which is the ice. Staff proposes this disallowance on the same basis as the proposed disallowance for the manual labor associated with this cost code. The Staff also indicated that there was an insufficient supply of ice at the beginning of the project until UE began making its own ice at its batch plant. UE asserts there is no evidence of inefficiencies with regard to the material cost of ice.

The Commission finds that the engineering study done of the potable drinking water system provides sufficient evidence of the problems concerning the ice portion of this cost overrun. If routes overlapped and services were duplicated, then ice was being wasted. The Commission finds the disallowance is reasonable based upon its findings concerning the manual labor costs associated with potable drinking water. The disallowance is $68,000.

iii. Telephones

Staff recommends a disallowance for telephone installation and billing. This disallowance is based on Staff's contention UE's monitoring and control of personal calls was inadequate and thus contributed to the cost overrun for this category. UE had its operators monitor calls on a random basis as time permitted. Operators would monitor the calls to determine if the calls were personal or business. UE took several other measures to reduce the number of personal calls. Some of those measures were: UE reduced the number of lines having outside access; UE restricted use of credit cards; UE increased security during nonworking hours to prevent persons from using the phones for personal use.

From review of the evidence with regard to this proposed disallowance, the Commission has determined that UE took sufficient measures to control the costs associated with the cost overrun for telephone calls. The Commission finds that the evidence does not support Staff's disallowance.

iv. Field Toilets

Staff proposes a disallowance of materials under the cost code "Portable Restroom Facilities". Staff bases its proposed disallowance on an engineering study performed by UE, UE correspondence and interviews with DIC personnel. Staff basically contends that there were 40 more portable facilities at the UE site than were necessary. Staff asserts UE failed to properly monitor the utilization and costs associated with field toilets and thus contributed to the cost overruns.

The engineering study was presented to UE management in April 1983. The study's stated purpose was to determine the number of field toilets being used, their location, how they were monitored, how many were required, and any possible cost reductions. The study indicated OSHA regulations required one toilet facility for each 50 workers. The OSHA study did not specify what was the appropriate distance a worker would have to walk to a toilet facility.

The engineering study concluded that the monitoring of the portable toilet facilities was adequate and that the number of toilets per number of workers was checked periodically and adjustments were made. The report concluded that OSHA requirements were being met, and in some areas exceeded. The study indicated that the areas were the number of toilets exceeded OSHA requirements were usually the outlying areas.

UE management's response to the engineering study was to remove nine restrooms and order further monitoring. UE asserts there is no evidence that it was imprudent or unreasonable in monitoring and maintaining field toilets for its personnel.

The Commission finds that the cost overruns in this cost code were not unreasonable when compared to the sanitary problems and work lost if adequate facilities were not provided. The engineering study found adequate monitoring was occurring and only nine toilets were removed based upon the engineering study. The Commission finds that UE's control of the cost and utilization of field toilet facilities was adequate and reasonable and that Staff's proposed disallowance is not supported by the evidence presented on this issue.

c. Subcontracts

The construction of the Callaway Nuclear Plant required the utilization of many subcontractors to perform specific work assignments. These subcontractors were generally under the supervision of DIC. UE as the owner utility retained approval of certain aspects of subcontractor performance. UE maintained responsibility for the requisition and award of subcontract work and the mobilization date of a subcontractor. Staff originally proposed to exclude costs from rate base costs associated with five subcontracts. Two of the five disallowances were settled, so only three proposed disallowances remained in dispute.

i. B&B Insulating Company

UE contracted with B&B Insulating Company (B&B) in July 1981, under a lump sum price contract, to furnish materials and equipment and labor for insulation of penetration closures. UE agreed to a mobilization date for B&B of August 3, 1981, based upon the number of penetrations ready to be sealed as projected by Bechtel. Three percent of penetrations were to be supplied to B&B by August 17, 1981, by DIC with drawings approved by Bechtel. B&B was not released to work until October 8, 1981, because the drawings had not received the appropriate approval until that date. Because of this delay B&B performed very little of its scheduled penetration closures during this time. The problems of providing enough penetrations for B&B to seal continued into November 1981. DIC recommended that B&B be demobilized at that time until March or May of 1982. The evidence indicates that many of the delays were incurred because of delayed Bechtel design. B&B, rather than be demobilized, proposed to remain on site and perform other work assigned to DIC. This was accepted by UE and DIC.

B&B's contract was modified in accordance with DIC and UE acceptance of B&B's proposal. The demobilization of B&B was extended due to required approval of the method used for sealing moisture out of penetrations. B&B began performing work under the contract modification in February 1982. B&B attempted to begin sealing penetrations in May 1982 under its original contract, but was delayed again because of the release of only a small number of penetrations. Because of this last delay B&B proposed additional modifications to its contract. UE approved one of the modifications proposed by B&B. The modification approved was the change of the contract from a lump sum to an actual cost plus 28.8 percent contract.

Staff proposes to disallow certain costs associated with the mobilization of B&B before work and specifications were ready and before drawings were approved by Bechtel. These costs result from a claim submitted by B&B and corresponding overhead during the time the claim covers. UE paid B&B $22,951 under this claim. Staff proposes to disallow the $22,951 plus $28,000 in overhead costs for the time period of the claim.

The second cost proposed to be disallowed relates to the expiration of shelf life materials procured by B&B for which UE had reimbursed B&B. These materials were requisitioned for the August 3 mobilization date and were made unusable because of the delays in providing penetrations to B&B. Staff proposes the disallowance for the shelf life materials of $42,226. Staff's total proposed disallowance is $75,000 Missouri jurisdictional.

Staff's disallowances are based on UE's failure to properly integrate the work and design at Callaway. UE proceeded to mobilize B&B even though design was not prepared to provide the drawings necessary for B&B to perform its work. This failure to know whether Bechtel was prepared to meet the requirements of B&B caused UE the additional costs proposed to be disallowed by Staff.

UE contends it was justified in mobilizing B&B when it did, given the then current knowledge. UE contends the penetration seals were required to be completed prior to fuel load, which was scheduled for October 1982. UE also contends that although B&B was not performing the number of closures as projected, it was performing some work which was beneficial to the construction project. UE contends finally that it was reasonable to bring the materials associated with B&B closures on in August 1981 so that the work to be performed by B&B could be done in an orderly fashion.

The Commission cannot accept UE's view of what is reasonable concerning the mobilization of B&B. UE's failure to properly integrate design and construction is again made painfully clear in this instance. Bechtel was not prepared to meet the requirements of B&B in August 1981 even though it participated in the decision concerning the mobilization date. UE had the responsibility of ensuring design was ready for construction before mobilizing B&B. The Commission finds it was imprudent management to let a subcontract for over a million dollars and not ensure the work was ready to be performed before the subcontractor was mobilized.

UE's focus on the fuel load date of October 1982 reinforces its complete failure to understand or realize how far from completion the Callaway project was in 1981. If UE had known how far behind design was, it would have known that the projected October 1982 fuel load date was unattainable. In fact, shortly after the mobilization of B&B the fuel load date was again rescheduled.

Staff's disallowance is based upon letters from B&B to DIC which outline the problems encountered because of early mobilization. The Commission finds this evidence is competent and substantial and finds that the evidence supports Staff's disallowance as reasonable.

ii. Owens-Corning Fiberglas

Staff's second proposed exclusion from rate base is for costs associated with the premature mobilization of Owens-Corning Fiberglas (OC). OC had two contracts with UE for insulation of nonmetallic thermal insulation. UE approved DIC and Bechtel's job mobilization for OC under the two contracts.

OC was mobilized in July 1981. This was nine months before work could be performed under one contract and fourteen months before work could be performed under the other contract. In August 1981 OC began billing UE one percent per month to cover the on-site expenses for a project manager and a quality control person, office building expense and storage warehouse expense. OC was paid $113,666 under one contract and $110,684 under the other contract for the periods prior to beginning work under the respective contracts. This is approximately $181,000 Missouri jurisdictional.

UE contends two people were on site during the period of alleged premature mobilization. These people, UE contends, were required for key administrative functions. UE contends further that a demobilization of OC would have cost more than paying OC the one percent payments. UE asserts finally that the $181,000 was part of the contract price and not an addition to it, and so was not an increased cost. UE witness Schukai indicated OC was mobilized in July 1981 because of the schedule, which projected that there would be sufficient work for OC at that time. Schukai did not know why the work was not ready as projected. The original contracts between UE and OC were changed to cost-plus contracts. Schukai stated the delay in having the piping ready for insulation influenced the decision to move to cost-plus contracts.

The Commission again cannot accept UE's explanation and rationalization for the premature mobilization of a subcontractor. In this instance UE took the schedule at face value and mobilized OC. This premature mobilization lasted nine months and fourteen months, respectively. During this time UE was forced to make payments to OC for personnel and expenses incurred. The eventual result of this delay was a change from lump sum contracts to cost-plus contracts.

UE would have the Commission reject the proposed exclusion based upon the cost savings of keeping OC mobilized as opposed to demobilization. This, the Commission believes, would reward UE for its lack of planning and failure to properly manage the project. The mobilization was premature because of UE's failure to integrate design and construction. Any savings UE made by not demobilizing are immaterial to this fact. Based upon the evidence presented on this issue, the Commission finds that Staff's proposed exclusion is reasonable.

iii. Diesel Generator

Staff proposes the Commission disallow $29,000 in costs associated with a 175 kw diesel generator installed in 1982 and replaced in 1983. The 175 kw diesel generator was replaced with a larger, 230 kw diesel generator. Staff proposes this disallowance because the 175 kw generator is not now being used and therefore is not used and useful. Staff also contends UE knew a year before it installed the 175 kw generator that the NRC was going to require the 230 kw generator.

The 175 kw generator was installed in the Technical Support Center. UE contends it proceeded with the installation of the 175 kw generator in order not to impact schedule and that UE did not know of the need for the 230 kw generator until after the 175 kw generator had been installed. UE contends that the change in the NRC requirement occurred after the installation and it had no control over that change. UE also objects to Staff's disallowance based upon the used and useful argument. UE states that the 175 kw generator is available for use as a portable power source in outage situations.

From the evidence, the Commission finds UE was aware of the changing NRC requirement concerning the size of the diesel generator for the Technical Support Center. The NRC changes were being proposed in February 1981. If UE witness Schukai was unaware of the change until mid-1982, it was something he should have known about prior to that time. The Commission finds that even if UE was not aware of the proposed change in the NRC requirement, the 175 kw diesel generator is not now used and useful and so the costs associated with that generator should be disallowed.

Based upon the above findings the Commission adopts Staff's proposed disallowance of $29,000.

11. NSSS Payments

The proposed disallowance on this issue involves the transportation of the steam generators manufactured by Westinghouse to be used by UE in Callaway I. NSSS is the Nuclear Steam Supply System, of which the four steam generators are an integral part. UE had responsibility for the transportation of steam generators from the point of shipment to the plant site. The contract between UE and Westinghouse provided UE could withhold 25 percent of each progress payment due during any delay of a major component if the delay was inexcusable. This is the only remedy provided in the contract in the event that Westinghouse failed to perform as agreed. The withholding of progress payments was a contract remedy to put pressure on Westinghouse to meet delivery dates. All withheld progress payments would be paid upon final delivery. The agreed-upon delivery date for the Model F steam generators was September 1978. In May 1978 UE became aware that Westinghouse could not meet this date. New shipping dates of October 2, 1978, for two generators and October 23, 1978, for the final two generators, were set. The steam generators were finally delivered to UE for transportation in May 1979 and September 1979.

UE had contracted with Reliance Trucking Company (Reliance) to haul the generators from the barge dock on the Missouri River to the Callaway plant site. UE mobilized Reliance in November 1978, May 1979 and October 1979. The three mobilizations were caused by the delays in shipment of the steam generators. UE attempted to backcharge Westinghouse for the cost associated with mobilizing Reliance. Westinghouse, though, refused payment, stating that backcharging for transportation was not a contract remedy. The only contract remedy available to UE was the withholding of the 25 percent of progress payments if there was a delay in delivery which was inexcusable.

Staff's proposed disallowance is the AFUDC related to withholding 25 percent of the progress payments from the original delivery date in September 1978 until the steam generators were delivered. The total amount of AFUDC is $242,442. Staff proposes this disallowance for several reasons, some of them briefed extensively. Although there may be some merit to Staff's legal arguments, the Commission believes it is more appropriate in this instance to address itself to UE's actions and whether those actions were reasonable under the circumstances.

Piecing together how UE made its decision to not withhold progress payments is essential in determining whether the decision was reasonable. The Commission has not found this process of piecing together the evidence easy, since there seems to have been no clear-cut decision concerning the withholding of progress payments. The March 3, 1981, Westinghouse/UE procurement meeting minutes indicate the original delivery date of March 1978 for Model D generators was changed to September 1978 with UE's agreement when the decision was made to accept the Model F steam generators. The September 1978 delivery date is the point at which Westinghouse failed to deliver major components under the contract. The delays were the result of engineering problems encountered by Westinghouse in the tubing of the Model F steam generators. UE was concerned with the delays in manufacturing the steam generators. The minutes of a June 13, 1978, meeting between Westinghouse and UE indicate UE in effect asked Westinghouse to show cause why manufacture of Callaway steam generators should not be stopped altogether.

At the hearing UE witness Schnell testified that in his professional opinion Westinghouse did everything possible to remedy the problem with the Model F generators and UE would have had extreme difficulty demonstrating the delays incurred were inexcusable. In Schnell's rebuttal testimony he states that UE balanced the need to expedite delivery of the generators against the right to delay and decided not to delay payments. Schnell, though, could not remember specifically when the decision was made and there was no documentation presented to show who made the decision or if and when a decision was made concerning the withholding of progress payments for the delay by Westinghouse. UE's position as stated in its brief is that the delays were excusable and that withholding payments would have been detrimental to expedited delivery.

The Commission has reviewed UE's position and the evidence presented by Staff. The Commission does not believe UE's final position in this matter is supported by the evidence, nor is it reasonable. As early as June 13, 1978, Schnell was threatening to cancel UE's order for the steam generators because of the delay (Exhibit C-125, Vol. 2, Appendix RJI-34, p. 11). Even if, arguably, the threat was only a negotiation tool, it is a serious threat and still indicates that UE thought Westinghouse was at fault for the delays. In addition, UE answered a data request from Staff which sought the reasons why progress payments were not withheld by stating that UE did not withhold the progress payments in order to better enable it to maintain its bargaining position with regard to certain transportation costs. (Exhibit C-125, Vol. 2, Appendix RJI-31 and Appendix RJI-31, p. 2). This reason does not support the testimony of Schnell.

The Commission is aware that UE had personnel at the Westinghouse facility to ensure the quality of the steam generators. This involvement of UE at the manufacturing level, though, is not dispositive of whether UE should have withheld the progress payments, as UE suggests. What it shows is that UE was concerned with the Westinghouse manufacturing process and wanted firsthand assurance that the steam generators were being built to specifications.

Based upon its review of the evidence as set out above, the Commission finds that UE should have withheld the progress payments as a means of ensuring that Westinghouse delivered the steam generators as soon as possible. The Commission is not convinced that withholding the payments would have interfered with the work on the generators or delayed expedited delivery. The Commission is not even convinced that this was a reason for the decision not to withhold the progress payments. There is no clear indication from the evidence why the decision was made. The Commission also is not convinced that the decision was made because of Schnell's professional judgment the delays were excusable. The responses to Staff data requests and the failure to provide any documentation or testimony of the actual decision are persuasive in refuting Schnell's testimony. The Commission believes it is a reasonable management decision to use contractual remedies to ensure performance. Based upon these considerations, the Commission finds that Staff's disallowance is reasonable. The disallowance is $242,000.

12. Operating And Maintenance

Operating and Maintenance (O&M) costs are those costs for the operation and maintenance of Callaway, other than wages, which relate to the first year of operation of the Callaway Nuclear Plant. These expenses are estimated since Callaway was not projected to go into service until early 1985. Staff and UE reached agreement on much of Staff's proposed disallowances of O&M expenses. The remaining issues are discussed below.

a. Rate Base Treatment Of Certain Capitalized Items

Staff and UE have agreed that certain O&M items should be capitalized rather than expensed. These items include a fuel inspection stand, underwater records, miscellaneous tools, shelving and pallet racks, miscellaneous racks, an order-picking vehicle, an electric forklift and an electric pallet lift. Staff contends these items have yet to be purchased and should not be allowed into rate base until they are purchased. UE contends that if the Commission capitalizes these items, which were originally expensed, the items must be included in rate base in this case. The amount in question would add $233,000 to UE's rate base.

Staff's basic argument is that these items have not been purchased and therefore inclusion of them in rate base would violate Section 393.135, R.S.Mo. 1978. Section 393.135 prevents any charge being made by an electric corporation which is based upon costs associated with owning, operating, maintaining or financing any property before it is fully operational and used for service. Staff asserts that since the items have not been procured, they are not operational and used for service.

UE contends that once Staff proposed to capitalize these items, they must be included in rate base. UE states that these items are for a budgeted test year and no assertion is made that they will not be purchased. UE argues there is no logical reason to allow projected year expenses but to disallow projected first-year capitalized items from rate base. UE points out this is another instance of regulatory lag, since after UE purchases the items it will not be able to include them in rate base until the next rate case.

UE also attacks Staff's reliance on Section 393.135 as misplaced. UE argues the Callaway Plant will be fully operational and used for service as of the date of the order. UE states that once Callaway is determined to meet the criteria of Section 393.135, the items to be purchased and capitalized cannot be excluded on that basis.

The Commission believes UE's reading of Section 393.135 is too restrictive. To follow that interpretation, UE can include the costs associated with any additional construction at Callaway before the ratepayers receive any benefit from the additional construction, once the Callaway Plant is determined to be in service. The Commission interprets Section 393.135 differently. In the recent Callaway II case decided by the Missouri Supreme Court, the court stated: "The manifest purpose of Proposition One (Section 393.135) was to make the utility wait until completion of new construction before including the cost in its rate base, or otherwise recovering its expenditures." State ex rel. Union Electric Company v. Public Service Commission of the State of Missouri (Docket No. 66014, decided February 26, 1985). The Commission believes that the Supreme Court statement means that where there is any new construction or items which are not operational and used for service at the time a Commission order is issued, a utility company may not charge ratepayers for costs associated with those items.

Even if Section 393.135 does not prevent the exclusion from rate base of the items in question until their purchase, the Commission believes the items should be excluded from rate base in this case because they are not used and useful until purchased.

b. NPI Costs In 1985

UE projects a cost of $2,310,000 for services to be provided by NPI during 1985. Staff proposes to disallow these costs. Staff's proposed disallowance is based on UE's failure to sign a contract with NPI for the services and the fact that the expenses for the services to be provided by NPI are not known and measurable.

UE contracted with NPI to provide certain services during the construction phase of the Callaway Plant. In 1981 it was recognized that NPI would be without work once the construction of Callaway was completed. NPI wanted a commitment that it would be retained after the commercial operation of Wolf Creek (the only other SNUPPS plant to be constructed). To make this assurance to NPI, UE, KCP&L and KG&E

signed a letter of intent in October 1981. No formal contract with NPI had been signed as of the date of the hearing regarding NPI's services during the operation phase of Callaway.

Staff has several reasons for its proposed disallowance. First, Staff states that since the legal obligations and derivative costs of a letter of intent are uncertain, it has little value as an auditing tool. Staff states that without a contract outlining the duties of NPI with regard to the operation phase of the Callaway Plant, the services to be performed by NPI are not defined and therefore the derivative expenses are not known and measurable. This is pointed out, Staff asserts, by the fact that UE based its projected expenses on its costs during construction and UE admits NPI's services will be different during operation of the plant than they were during construction. UE's witness Rinke admitted that one could not tell from the letter of intent what services performed by NPI during construction would be continued during operation. Rinke admitted further that at the time the letter of intent was signed there was no way to ascertain what services NPI would be asked to perform during the operation phase of the Callaway Plant.

UE's position is that the signing of a contract to formalize its relationship with NPI during operation of Callaway is not a high priority item. UE UE states it has worked with NPI very closely during construction and they have a long-standing trusting relationship. UE states the general nature of NPI's work at Callaway will remain the same during the operation phase of the plant. UE asserts NPI will perform the work projected, that it must have NPI's services, and that there is adequate evidence to justify the projected 1985 costs of the NPI work.

UE supports its position with several points. UE states that the Final Safety Analysis Report (FSAR) issued by the NRC requires UE to utilize NPI's services during the operation phase of Callaway. Second, the long-standing use of NPI's services, and especially those services from September 1983 to August 1984, allow UE to adequately project the cost of NPI services for 1985. Third, industry experience indicates NPI will have a similar number of contracts to administer as those NPI administered just prior to initial operation. Last, UE states that the letter of intent goes into some detail concerning NPI's work assignments during the operation phase of Callaway and this provides sufficient scope of work in order to review NPI's expenses to determine whether they are reasonable.

The significant point concerning this issue is whether the costs projected by UE are a reasonable projection of the costs of NPI's services for 1985. The Commission does not believe a letter of intent written in 1981 can provide the basis for reviewing the reasonableness of the work projected for NPI. On cross-examination Rinke admits that UE did not use the work scope set out in the letter of intent to develop the projected costs. UE used the September 1983 to August 1984 costs for NPI to project the 1985 amount. The Commission determines that this is not a reasonable basis for projecting NPI 1985 expenses in light of the changed circumstances of NPI's work. The switch from construction phase to operation phase will be a significant change in the scope of work of NPI. Although NPI's main activity of coordination will remain the same, the specific nature of that coordination will be different and there is no basis upon which to determine what those specific functions will be. The number of contracts to be administered may be the same, but their complexity and scope will change. Without a formal contract setting out specific duties and scope of work, the Commission is without a basis on which to judge whether the expenses associated with NPI are justified and reasonable. The Commission is aware it must make a reasonable forecast of expenses for 1985. State ex rel. Missouri Public Service Company v. Fraas, 627 S.W.2d 882 (Mo. App. 1981). The Commission, though, must have a reasonable basis for making such a forecast, and it finds the evidence presented by UE is insufficient for that purpose. The proposed disallowance of Staff will therefore be accepted.

13. Budgeted Nuclear Labor Costs

Staff's proposed disallowance is for unfilled positions in UE's Nuclear Operations Department. Staff proposes this adjustment because UE has included wages and expenses in its 1985 budget for positions to be filled. Some of these positions have not been filled. UE argues that use of projected numbers is an accepted procedure in ratemaking and it fully intends to fill the positions. UE states further that there is sufficient evidence in the record to allow the recovery of the costs associated with the unfilled positions.

The Commission finds that UE's projection is reasonable and that Staff's proposed adjustment should not be made.

a. Expenses Associated With Unfilled Positions

The disallowance proposed by Staff on this issue is for costs associated with unfilled positions in UE's Nuclear Operations Department. The expenses proposed to be disallowed are for such items as individual expense accounts, stationery and supplies, transportation, rental office equipment and miscellaneous. This disallowance is related and flows from the issue, Budgeted Nuclear Labor Costs. The Commission did not adopt Staff's disallowance for budgeted nuclear labor costs and so will not adopt the disallowance for expenses associated with those labor costs.

14. AFUDC Adjustments Not Related to Direct Man-hours

Staff has disallowed AFUDC associated with each of the adjustments not related to direct man-hours at the point in time or over the time period that the adjustment occurred. The Commission concludes that this adjustment is reasonable. This adjustment amounts to a $54,541,000 disallowance.

15. Callaway I And II Allocation

Staff and UE disagree as to the proper method to allocate SNUPPS/NPI architectural and engineering costs between Callaway I and the cancelled Callaway II plant. Staff proposes to allocate $20,392,000 to Callaway II. Public Counsel recommends that the cost be allocated on a 50-50 basis.

The difference between UE and Staff arises from the method of allocation. UE allocates only those A/E costs that are related specifically and used exclusively in support of Unit No. II. UE maintains that essentially all of the Bechtel A/E costs were required for Unit I whether or not there had been a second unit.

Staff uses an incremental cost approach. This approach is based on the SNUPPS agreement which required UE to pay a two-unit share of the design costs. Since UE commenced construction with a two-unit program, it incurred $26.9 million more in costs than if it had commenced with a one-unit plant.

The Commission concludes that Staff's allocation method should be adopted. Staff has established that UE's two-unit program resulted in greater A/E costs than if one unit had been planned. Thus, Staff's allocation to unit II of $20,392,000 represents the A/E costs incurred at Callaway that can be attributed to unit II by reason of the SNUPPS cost-sharing agreement.

The Commission determines that Public Counsel's approach should be rejected since it would attribute cost to Callaway II which exceed the incremental cost differences associated with a one unit versus a two-unit program. Public Counsel's method would improperly exclude costs associated with designs which were required for the construction of Unit I.

B. Public Counsel's Rate Base Proposal

Public Counsel presents an analysis of UE's cost estimates and UE's capacity planning efforts in the 1970s. Public Counsel also presents an analysis of the economic viability of the Callaway unit. Public Counsel concludes that the operation of Callaway over 30 years is projected to cost $3 billion more in present value dollars than if Callaway had never been built. Public Counsel recommends a rate base proposal designed to share the alleged $3 billion loss between shareholders and ratepayers.

Public Counsel asserts that UE was aware of the risks associated with nuclear power when it decided to proceed with the nuclear project and that UE failed to take into account risks and uncertainties related to the Callaway choice until UE cancelled Callaway Unit II.

Public Counsel focuses on UE's coal versus nuclear studies which were performed in 1974, 1977, 1979, 1980, 1981 and 1982. These studies employed nuclear capital costs which, as discussed in Section II C and D above, were severely underestimated in 1979, 1980 and 1981. In addition, these studies employed outdated and unrealistic O&M cost. As a result, UE's coal versus nuclear studies were still showing Callaway I as the least cost generation option when UE decided to cancel the unit. At the time UE cancelled Callaway II, UE recognized that its studies did not represent what was happening with regard to nuclear plant costs.

Public Counsel's description of UE's capacity planning efforts during the 1970s show that in 1972 UE predicted a need for 2000 megawatts of capacity after completion of Rush Island No. 1 and Rush Island No. 2 in 1975 and 1976 and before the operation of a 1200 megawatt nuclear unit in 1981. UE's studies indicated that the best economic alternative was 2000 megawatts of combustion turbines.

In 1973, UE determined that 1500 megawatts of capacity should be added between the completion date of Rush Island No. 2 and the completion date of Callaway I. The additions would include 300 megawatts of combustion turbines and two 600 megawatt coal cycling units, Rush Island No. 3 and Rush Island No. 4. Public Counsel takes the position that UE recognized in 1973 that its capacity plan was overly base loaded and the lack of peaking capacity would lead to minimum load problems at UE's base load units.

In 1974, UE's planning committee recommended 1700 megawatts of additions between Rush Island No. 2 and Callaway I, consisting of 500 megawatts of combustion turbines in 1978 and two 600 megawatt coal units for 1979 and 1980. Minimum load problems were again identified.

Late in 1974, Rush Island No. 3 and No. 4 were replaced with combustion turbines. One of the reasons cited for this decision was a higher percentage of base capacity causing serious minimum load problems which called for peaking capacity. In addition, UE identified reliability benefits since the megawatt amount of combustion turbines could be fine-tuned to meet changing load forecast at substantial cost savings over larger units, thus allowing delay or cancellation of units if load growths suddenly slackened with minimum or no economic detriment.

As it turned out, UE has constructed 150 megawatts of combustion turbines and one base load nuclear plant since the addition of Rush Island Unit II.

Public Counsel contends that UE failed to consider the economics of completing Rush Island No. 3 and No. 4 instead of the Callaway plant. In addition, Public Counsel suggests that UE should have considered replacing Callaway I with peaking capacity.

In the Commission's opinion Public Counsel is relying on hindsight and second guessing UE's capacity expansion plan which was established in 1974. The plan provided for both base and peak load units. Rush Island No. 3 and No. 4 had been cancelled by the time the Commission granted UE a certificate to construct Callaway. Thus, the Commission accepted UE's projections with regard to the economics of the nuclear plant in 1975. Although later in the project UE should have reassessed its capacity plan with regard to the economics of completing Callaway I, UE's plan in 1974 showed a need for base load as well as peaking capacity and the economic studies showing the advantage of nuclear over coal were deemed to be reasonable. Thus, the Commission finds no imprudence with regard to UE's original decision to construct the Callaway plant.

Public Counsel's analysis of the economic viability of Callaway was presented by Public Counsel witness Dr. Rosen. Dr. Rosen compared two required revenue streams over a 30-year period, one with Callaway completed and operating (the "Callaway in" case) and the other assuming that Callaway had never been constructed where alternative generating capacity provides the required energy and power to the system (the "Callaway out" case). Dr. Rosen identified seven components of required revenues which would be affected by the two scenarios: (1) Callaway capital costs; (2) nuclear O&M costs; (3) nuclear capital additions; (4) nuclear fuel expense; (5) spent fuel disposal costs; (6) decommissioning costs; and (7) replacement costs.

Dr. Rosen utilized UE's estimate of the completed costs of Callaway of $2.85 billion. Dr. Rosen employed a $64 million O&M expense for 1985 in contrast to UE's estimate of $34 million for 1985. Dr. Rosen projects O&M increases over 30 years at approximately one percent above inflation, whereas UE assumes the rate of inflation. This difference is substantial over 30 years.

Dr. Rosen assumes annual capital additions of $36 million in 1985, increasing to $52 million in 1999 and remaining at $52 million until the year 2009 and then declining to less than $10 million by the year 2014. UE's evidence with respect to capital additions is inconsistent. UE's construction budget estimates the total of $77 million in capital additions for the first nine years of Callaway, while UE witness Aikman projects approximately $80 million per year.

Dr. Rosen calculates nuclear fuel based on an assumed capacity factor of 66 percent for Callaway. He considers the assumption optimistic since, based on industry experience, average capacity factor of 56.7 percent would be expected in the first 10 years of Callaway operation. Dr. Rosen attempted to use UE's estimates of nuclear fuel costs where available. However, UE did not project fuel expenses beyond the year 2000. Dr. Rosen escalates the direct fuel component at a rate of seven percent annually through the year 2014, which is a real growth rate of one percent above the assumed inflation rate.

Dr. Rosen has adjusted the current DOE fee for spent fuel disposal costs assuming UE electricity use and assuming the fee will escalate at the rate of inflation throughout the plant life. This fee is related to the DOE charge for the disposal of spent fuel. DOE is responsible for the disposal of spent fuel and is in the process of selecting a disposal site. The current charge is one mill per kwh for this future service.

Dr. Rosen estimates $300 million in 1983 for decommissioning costs. This figure contrasts with UE's and Staff's stipulated amount of $120 million on a total company basis, which the Commission has accepted in this case.

The "Callaway out" scenario assumes UE's demand forecast, firm purchases and the addition of combustion turbines in the mid to late 1980s (810 megawatts of combustion turbines between 1984 and 1992), and three 400 megawatt coal plants to replace Callaway in 1996, 1997 and 1998.

Extensive testimony was presented by UE witness Dr. Hieronymous attacking the underlying assumptions utilized by Rosen in each category of his analysis.

As noted above, Dr. Rosen's analysis concludes that the construction of Callaway will result in approximately $3 billion in losses over the life of the plant.

Public Counsel recommends that these alleged losses associated with the Callaway plant be shared between shareholders and ratepayers utilizing a sharing concept which has been used for cancellation costs. Public Counsel points to UE's proposal in Case No. ER-83-163, regarding Callaway II cancellation costs. In that case, UE proposed that the cancellation costs be amortized and that no return be allowed on the deferred amount of cancellation costs over the amortization period.

Public Counsel argues that regardless of prudency questions, Callaway turned out to be a mistake. Thus, in Public Counsel's view the consequences of the mistake should be shared between ratepayers and shareholders. Public Counsel contends that this sharing approach is supported by the Commission's statutory duty to set just and reasonable rates.

Public Counsel proposes that the sharing of losses be accomplished by allowing one-half of the return on Callaway rate base and full depreciation and taxes on the entire Callaway investment.

In the Commission's opinion, 30-year projections are speculative even if the underlying assumptions are well reasoned. In this case, the Commission has accepted assumptions related to O&M costs and decommissioning costs which are not consistent with Dr. Rosen's assumptions. Upon the evidence herein, the Commission is unable to find that the Callaway nuclear plant represents a $3 billion loss.

1. Performance Standard

In his direct testimony, Dr. Rosen recommended the establishment of a performance standard for Callaway to give UE management an incentive to operate Callaway as efficiently as possible and protect ratepayers from poor plant performance. Public Counsel has recommended two alternate proposals regarding the establishment of a performance standard. Under both proposals, Public Counsel utilizes the availability rate for Callaway which the Commission adopts in this proceeding as the point above and below which the standard should apply.

If Public Counsel prevails on its recommended rate base exclusion of Callaway I, Public Counsel proposes that any net additional costs or savings due to the operation of Callaway at a lower or higher level than the availability rate for Callaway adopted by the Commission should be shared on a 50-50 basis between ratepayers and stockholders. Net additional costs refers to the difference between fuel and purchase power expense actually incurred and the level of these expenses as determined by the Commission in this case.

If Public Counsel's proposal regarding rate base exclusion is rejected, Public Counsel recommends that if Callaway operates at an availability rate below the availability rate for Callaway adopted by the Commission, anywhere from 50 percent to 100 percent of the net additional cost due to this poor operation should be borne by UE stockholders unless this unduly impairs the financial integrity of UE. Under this proposal, Public Counsel would not favor UE's receipt of any net additional savings should Callaway perform better than the level set by the Commission.

The Commission has considered the Public Counsel's proposal and adopts UE's argument that the performance standard is already inherently built into the calculation of fuel cost in this case. Test year fuel cost requires a specific value be set for the first year's availability rate for the operation of Callaway. Thus, if the plant operates above that availability range, then all else being equal UE will actually spend less than test year fuel expenses and will profit by the difference. If the plant runs at a lower availability rate then actual fuel costs will be higher than that allowed level and UE will lose the difference. In this case, the Commission has set a relatively high availability rate based on the evidence and recommendations of the various parties. Thus, the Commission concludes that a relatively strict performance standard is built into the rates to be established in this case.

C. Additional Rate Base Adjustment

The Commission has found herein that some aspects of UE's management of the Callaway project were inefficient, imprudent and unreasonable. In particular, the Commission has found that UE failed to adequately integrate the construction and engineering schedules, resulting in waste and inefficiency at the project. Secondly, the Commission has found that UE failed to correctly assess the remaining amount of work to be completed until very late in the project. In addition, the Commission has found that UE failed to fully implement an effective cost accounting system. Based upon these findings, the Commission has made specific adjustments to rate base related to inefficiencies, direct labor, indirect costs, and AFUDC associated with those costs.

In determining the price to be charged for electricity, the Commission must consider all relevant factors which in its judgment have any bearing upon the issue. After considering all the competent and substantial evidence in the record, the Commission finds that there are several additional factors that must be considered in arriving at the proper dollar amount to be included in the Callaway rate base.

At the time of the certification case and during the entire course of the construction project, UE has represented to the Commission that the Callaway unit would be rated at 1150 megawatts of capacity. However, it was adduced at the hearings in this case that the plant is licensed by the NRC at 1120 megawatts. UE plans to apply to the NRC for a "stretch" rating to achieve the 1150 megawatt rating sometime in the next five years. Thus, UE may receive a "stretch" rating sometime in the future although no assurance exists that the "stretch" rating will ever be granted.

Staff and Public Counsel argue that the ratepayers are being asked to pay for the capital costs of a generating unit with a potential net electrical capability of 1150 megawatts, when in fact the unit will be providing 1120 megawatts of capacity. Staff and Public Counsel have suggested that the Commission adopt a 1150 megawatt rating of Callaway for the purpose of determining overall fuel costs. The Commission has rejected the proposed adjustment since Callaway is presently licensed at 1120 megawatts. However, the Commission believes that it is appropriate to consider this reduced capacity rating in determining the amount to be included in rate base for Callaway. The Commission notes that 30 megawatts represents approximately 2.6 percent of the total capacity approved for Callaway Unit No. 1 by the Commission in Case No. 18,117.

The Commission has also found that UE and SNUPPS/NPI failed to adequately monitor Bechtel costs, although no specific adjustments for Bechtel manhours have been proposed.

In addition, UE's coal versus nuclear studies in the late 1970's were outdated and unreliable, and yet continued to be used by UE management to assess the viability of Callaway in relation to alternative capacity expansion options. Apparently, UE never seriously considered other options once it began construction on Callaway, even after the only SNUPPS partners with nuclear experience cancelled their nuclear projects in 1979 and 1980. The coal versus nuclear studies used by UE appear to have been specifically designed to justify the nuclear option already undertaken, rather than to objectively evaluate the nuclear plant in relation to other generation expansion alternatives. Based upon the changes that were occurring throughout the nuclear industry, UE should have known that its coal versus nuclear studies were not realistic and reliable.

UE exhibited a general inability to target the cost of the plant, as described in a detailed litany of budget and estimate changes elsewhere in this order. UE also exhibited a continuing inability to recognize the risks associated with increasing capital costs of new nuclear plants. For example, UE twice reduced its contingency allowance, apparently under illusion that future uncertainties related to the construction of Callaway had been reduced. The Commission believes that based upon the changes that were occurring in the nuclear industry, efficient, prudent management should have been able to recognize these increasing risks.

The Commission has a statutory duty to set just and reasonable rates and in doing so must consider all relevant factors while balancing the interests of shareholders and ratepayers.

> Ratemaking bodies, within the ambit of their statutory authority, are vested with considerable discretion to make such pragmatic adjustments in the ratemaking process as may be indicated by the particular circumstances in order to arrive at a just and reasonable rate. State ex rel. Valley Sewage Company v. Public Service Commission, 515 S.W.2d 845, 850 (Mo.App. 1974).

In considering all relevant factors concerning the prudence and efficiency of the Company's management in relation to the Callaway project, the Commission finds and concludes that an additional $100 million should be excluded from rate base. In arriving at this adjustment, the Commission has considered the interest of ratepayers in not being solely responsible for bearing the risks of imprudent management by the Company. The Commission has balanced this ratepayer interest with the shareholders' interest in the financial integrity of the Company.

IV. Real Estate Taxes

This issue has been partially resolved by the Missouri Tax Commission by assessing the Callaway Plant as distributable property prior to December 31, 1984. The Missouri Tax Commission has not ruled on the amount of tax owed by UE so this amount is still in question. At the true-up hearing Staff agreed that UE's real estate tax estimate of $35,673,000 should be used. The only remaining issue is whether to make the $35,673,000 subject to refund.

Even though UE witness Brandt during cross-examination agreed that a refund would be reasonable, Staff counsel indicated at the true-up hearing that such a refund might not be legally justifiable. The Commission has determined that UE may adjust the Phase II settlement agreement by the addition of $35,673,000 for real estate and personal property taxes. This amount shall not be subject to refund.

V. Income Taxes

This issue was raised by UE in the Phase III portion of this case over the objection of Staff. Staff's objection was stated as follows:

> MR. HARRELSON: At this time I would like to preserve for the record an objection to Exhibit C-177. It is the position of the staff that the issue of interest synchronization is not one related to Callaway. It is simply an issue involving the construction of the Internal Revenue Code and Regulations promulgated pursuant to it, and it's an accounting issue not unique at all to the Callaway situation or the fact that Callaway is being brought into rate base. On that ground, this issue should have been raised in Phase II which was settled, and I would move to strike the testimony of Mr. Brandt on that basis. I think the issue is improperly raised in this phase of the proceeding.

UE's response to the objection was:

> MR. AGATHEN: ... I would agree with Mr. Harrelson that on a philosophical view, I guess it is an accounting issue not unique to Callaway. The only reason the company is presenting this issue to the Commission in the Callaway Phase III portion of this case is that certain information came to us, as indicated by Mr. Brandt's testimony, after the signing of the Phase II settlement. Therefore, we thought it important that this additional information be brought to the attention of the Commission so that they may decipher the matter themselves on the basis of all the available information at the present time.

Since UE agrees this issue is not unique to Callaway and therefore should have been settled in Phase II of these proceedings, the Commission is sustaining Staff's objection. UE will treat its income taxes as stipulated in Phase II of these proceedings.

VI. Depreciation

Part of the revenue requirement sought by UE in this case is for depreciation expense of the Callaway Plant. The depreciation expense is determined by developing an annual depreciation accrual rate and multiplying that percentage times the depreciable base of Callaway. The annual depreciation accrual rate is developed primarily from four factors. Neither party utilized historical data in this case to develop its rates, because no historical data exists for the Callaway Plant. The four factors utilized are:

(1) estimated date of plant retirement;

(2) estimated future interim retirement activity;

(3) estimated future interim additions; and

(4) estimated net salvage value.

UE and Staff agree on the estimated date of plant retirement of 39.5 years. This is arrived at by adjusting the 40 years operating license by the six months required for start-up testing. UE and Staff agree on the negative net salvage value of 10 percent for units of property retired in the future.

UE and Staff differ over the estimated future interim retirement rate and the estimated future interim addition rate and therefore over the annual depreciation rate to be used in this case. UE developed a 3.53 percent annual depreciation accrual rate based upon the agreed-upon 10 percent net salvage value, an estimated retirement date of 39.5 years, and a 28.6 year average service life. The average service life was computed based upon a .03 percent average interim retirement rate and a 2.8 percent annual interim addition rate. The contested portions of this issue involve the interim retirement rate and the interim addition rate.

UE's witness Aikman presented the calculation of UE's annual depreciation rate. To develop his rate Aikman prepared a study involving ten Westinghouse pressurized water reactors. Callaway uses a Westinghouse pressurized water reactor, and Aikman determined that these plants would provide data similar to what Callaway would experience in the future. Aikman chose the specific ten plants in his study because he could obtain the data he needed about those plants. Aikman collected data concerning each of the ten plants and from that data developed his .03 percent rate for interim retirement activity and 2.8 percent rate for future additions.

Staff proposed a .01 percent interim retirement rate and argued that no adjustment of service life should be made for interim additions. Staff witness Love used his own judgment to reach the .01 percent interim retirement rate. Love performed no study to support this percentage.

Staff did attack UE's .03 percent figure on the basis of the data used by Aikman to develop the percentage. Staff witness Rosenbaum analyzed the plants used by Aikman in his study and the data used by Aikman to determine what were the causes of the high percentages of retirements and additions for those plants. What Rosenbaum discovered was that four of the ten plants used in Aikman's study had major retirements and additions because of regulatory changes. The plants used in Aikman's study were built prior to some of the major accidents in nuclear plants, and therefore were subject to major modifications to meet the requirements resulting from those accidents. Rosenbaum felt that UE's advanced design made the possibility of these major modifications occurring at Callaway improbable.

Rosenbaum recalculated the interim retirement rate by removing the four plants he felt were affected by abnormal circumstances. Rosenbaum also removed the four plants which he felt had interim additions caused by abnormal circumstances. Using the remaining six plants, Rosenbaum found that the interim retirement rate was approximately .01 percent and the interim addition rate was approximately 1.9 percent. Rosenbaum testified he would not have conducted a study to determine the interim retirement rate or interim addition rate in a manner similar to the method used by Aikman, but that based upon Aikman's data, the percentages he developed better reflected industry experience. Rosenbaum testified he would have used a random sample rather than selecting plants on the basis of the availability of data and this would have provided a more statistically sound study.

Staff's primary objection to using an interim addition rate to adjust the service life of Callaway is the prohibition in Section 393.135, R.S.Mo. 1978. Staff argues that the additions are future plant replacements and as such come within the purview of Section 393.135. Staff argues the future additions cannot be used to compute a depreciation rate, since this is a method of recovering costs, until the additions are fully operational and used for service.

Staff argues further that even if Section 393.135 does not prevent the use of an interim addition rate in determining an annual depreciation rate, Aikman's percentages should be rejected on two bases. The first is Aikman's inclusion of the four plants with abnormal conditions and the second is the significant difference between Aikman's yearly addition rate and the costs projected for retrofits by other UE personnel. Aikman's rate predicts for the period 1986 to 1988 that UE will experience $239,400,000 in additions. UE's projected retrofits and plant replacements over the same period of time are $3,680,000. Staff suggests that this significant difference points out the unacceptability of Aikman's rate.

The Commission has reviewed the evidence as presented by UE in support of its proposed depreciation rates. The Commission has determined Aikman's study is seriously flawed because of his failure to randomly select the plants used in his study and his failure to deflate his rates sufficiently for the large retirements and additions associated with certain of the plants used in the study. The Commission considers the adjustments made to Aikman's study by Rosenbaum reasonable and justified based upon the causes of the abnormal circumstances at the plants he excluded. Based upon Rosenbaum's adjustments, the Commission finds the interim retirement rate for Callaway should be .01 percent. The Commission finds the interim addition rate of 1.9 percent, as developed by Rosenbaum, is also justified. The Commission, though, considers that the depreciation rate in this case cannot reflect an interim addition rate because of the prohibition of Section 393.135. The Supreme Court has stated that the purpose of Section 393.135 is "to make the utility wait until completion of new construction before including the cost in its rate base, or otherwise recovering its expenditures." State ex rel. Union Electric Company v. Public Service Commission of the State of Missouri, (Missouri Supreme Court, Docket No. 66014, decided February 26, 1985).

Thus, the Commission cannot impose on current ratepayers a depreciation cost for new additions until those additions are fully operational and used for service. Based upon the above discussion, the Commission therefore adopts Staff's annual depreciation rate of 2.6 percent.

Staff has also proposed that UE be required to maintain its depreciation reserve by primary plant account. According to Staff witness Love, the primary plant account method is necessary in order to have the data needed to develop a remaining life rate. The Commission considers this request reasonable and finds UE should maintain its depreciation reserve by primary plant account for the Callaway Plant.

UE, as part of its proposed phase-in, has requested that the Commission allow it to utilize units of production for the first three years of the phase-in. At the true-up hearing UE witness Brandt testified that because he had based his units of production depreciation on a lifetime capacity factor of 70 percent and that 70 percent was to be the capacity factor in the first year, that the units of production method would have no revenue requirement benefit as originally proposed. Brandt did suggest there were a variety of other reasons for utilizing the units of production method. The Commission has decided to allow the units of production method to provide UE flexibility to adapt to any significant changes in the operation of Callaway for financial statement purposes.

VII. Decommissioning Fund

Because a nuclear power plant contains radioactive material, it requires special procedures for guarding against any contamination once the plant is no longer in service. This decommissioning process associated with the safeguarding of the plant is expensive and uncertain. The cost of decommissioning far exceeds any salvage value the plant might have. As part of the rates the ratepayers pay during the operation of the plant, UE will collect funds for the decommissioning of the plant. Staff and UE have agreed upon the amount to be collected. The remaining issue is how the funds should be handled.

UE proposes to collect the funds in a manner similar to depreciation and use them to operate the plant. This method is called net negative salvage value. This method, UE states, will reduce the operating costs of the plant. UE then proposes to borrow the funds required for decommissioning at the end of the service life of the plant.

Staff proposes the use of an external fund to collect the moneys for decommissioning. This would be an external trust fund kept by a trustee separate from other UE funds and usable only for decommissioning costs. Staff proposes this approach because this method would ensure the moneys would be available for decommissioning. Staff also proposes the fund to take advantage of the 1984 tax law which allows a utility to deduct certain deposits to the fund in the year the deposits are made.

Both UE and Staff weighed their proposals in light of similar criteria. UE chose the net negative salvage approach because of the lower cost and the availability of the funds for use during the life of the plant. Staff chose its approach because of the need for assurance that the money would be available for use when decommissioning occurs. Staff's method is approximately $10 to $12 million more costly, discounted to present value, than UE's, while UE's method lacks assurability that UE could borrow the money for decommissioning when the plant goes out of service.

There are several reasons which support UE's proposal. The lower cost is significant, as well as the fact that the use of the money would require UE to borrow less externally during the life of the plant. UE also raises some concerns about the implementation of the 1984 tax law. UE states the law is uncertain and there are no guarantees the external fund would be acceptable to the IRS. UE also is concerned that only funds for decommissioning the radioactive part of the plant will be considered tax deductible.

The Commission has considered UE's proposals and concerns but agrees with Staff that the dominant requirement of the decommissioning fund is assurability. The risk and costs involved in nuclear plant operation and decommissioning far outweigh the additional costs of Staff's method. The Commission wants to ensure that the moneys paid by ratepayers during the life of the plant are available for decommissioning. UE's proposal provides no real assurance the funds will be there when they are needed. The Commission also believes that UE can meet the requirements of the 1984 tax law and that they are not as uncertain or unattainable as UE speculates.

Staff has proposed that UE (1) be required to design the fund so all deposits qualify for the tax exemption; (2) select a responsible person to act as trustee for the fund; (3) consider selecting a brokerage firm to serve as custodian of the fund to avoid the possible payment of two commissions for the same bond purchase; and (4) be required to follow the three investment criteria of Staff witness Smith.

The Commission has reviewed the Staff's recommendations for establishing the fund. The Commission has adopted Staff's recommendation that an external fund be required of UE. The Commission is of the opinion that the requirements placed on the fund in order to receive the tax deduction are sufficient guidelines to ensure proper investment of the fund. The Commission also believes that UE has sufficient expertise in dealing with trust funds to properly establish the fund to take advantage of the tax requirements. The Commission therefore will not set out specific investment guidelines for UE to follow. The Commission, though, requires that UE establish the external fund to take the maximum advantage of the 1984 tax law and follow the requirements of the tax law in making investments for the fund.

In order to ensure the lowest cost fund, UE will solicit bids of at least five potential trustees. UE will be required to review the possibility of having a brokerage firm act as custodian of the funds to prevent the possibility of paying two commissions for the same bond purchase. UE must select an interim trustee to hold the fund until the permanent trustee is selected. The Commission believes UE should make payments to the fund in accordance with IRS regulations and does not oppose the use of the funds by UE between each payment if IRS regulations permit. The parties have agreed, and the Commission concurs, that the deferred tax balance arising from the external fund be added to rate base.

The Commission has also determined UE should have the trustee report to the Commission on an annual basis concerning the receipt of the funds, the investments made, the costs incurred and the income of the trust. The trustee must prepare the federal and state income taxes for the trust and file a copy of all documents filed with any other state or federal agency with the Commission.

VIII. Fuel Inventory

This issue is interrelated with Nuclear Fuel Costs and Total Fuel Costs. The issues set out under the topic Fuel Inventory in the hearing memorandum are all dealt with under the other two topic headings except for the treatment of the unamortized portion of the Westinghouse nuclear fuel credits. The credits are those received by UE from its settlement with Westinghouse. The amortization of the credits is discussed as a separate issue. The issue here is the treatment of the unamortized balance of the credits during the period of amortization.

Originally, UE proposed to offset the nuclear fuel inventory by the unamortized Westinghouse credits. In rebuttal testimony UE changed its position and proposed to continue to record negative AFUDC on the Westinghouse credits until the time these credits are flowed back to the ratepayer. UE states that because of this treatment it is inappropriate to reduce its rate base for these unamortized credits.

In its brief UE asserts the negative AFUDC method in effect accrues a carrying cost or interest for ratepayers in the value of the credits just as AFUDC is accrued on construction work in progress. UE states this is the current method of treating the credits and there is no valid reason to switch at this time just because a portion is now being flowed back to ratepayers.

Staff proposes the Commission adopt UE's original position. Staff asserts it is not appropriate to include the unamortized balance of credits in rate base. Staff witness Rackers set out Staff's position as follows: "The Westinghouse credits represent funds which are available to the Company for use at their discretion. In fact, nearly half of the accumulated credits represent direct cash payments which have been available to the Company since 1980. Including these credits in rate base merely recognizes the carrying cost associated with these funds on a current basis." (Exhibit C-118). Staff states UE is not flowing through the carrying cost of the credits on a current basis, but instead is proposing to include it as an offset to future fuel loads.

The Commission has considered the two proposals and has determined the more appropriate method in this instance is to continue the accrual of negative AFUDC as proposed by UE. The Commission does not believe there should be a reduction in rate base to offset carrying costs on a current basis.

IX. Nuclear Fuel Costs

This topic involves several subissues which are related but require separate discussion and analysis. Those subissues are discussed in the separate sections below. This overall issue is the result of a contract settlement between UE and Westinghouse based upon Westinghouse's failure to fulfil a contract for uranium. The settlement agreement between UE and Westinghouse resulted in UE's receiving a certain amount of uranium from Westinghouse, cash and credits as compensation. The issues discussed below involve how to treat those credits for ratemaking purposes.

A. FIFO Versus Average Cost Accounting

This subissue involves how UE should value its nuclear fuel inventory for ratemaking purposes. UE proposes to value its nuclear fuel inventory on a weighted average cost basis. Staff proposes to use the first in, first out (FIFO) method. UE proposes the weighted average method because it is widely used throughout the public utility industry and it tends to smooth the costs of nuclear fuel over time. This prevents sharp increases or decreases in the costs associated with nuclear fuel inventory. This is also the method most widely used for fossil fuels. UE argues that the FIFO method should not be accepted because "if the carrying cost rate exceeds the escalation rate of the fuel, FIFO would produce a higher price than would weighted average." UE states further that FIFO leads to a rate increase of $16,647,000 in this rate case over weighted average. UE concludes that it is looking at the accounting method for valuing nuclear fuel inventory over the next 40 years and the weighted average method is the most appropriate long term method to utilize.

Staff proposes FIFO mainly because of its matching of costs with cost occurrence. Staff supports FIFO because it is systematic and easy to apply, and it assures the lowest price during periods of escalating costs. Staff states that one of the principal advantages of the FIFO method is its combination with Staff's proposal for the treatment of Westinghouse credits. Staff matches the Westinghouse credits with the higher priced first and second fuel loads, thus reducing the effects of the higher priced early fuel loads. The majority of the Westinghouse credits are proposed to offset the higher priced fuel. Staff contends, finally, that the weighted average method allows UE to manipulate the costs of the nuclear fuel inventory by moving the cutoff date for averaging.

The Commission has considered the two methods proposed for valuing UE's nuclear fuel inventory. The Commission has determined the weighted average method is the more reasonable method to be utilized over the life of the Callaway Plant. As pointed out by UE, the FIFO method would increase rates in this case approximately $16 million. Since there is substantially no difference between Staff's and UE's treatment of the fuel credits, Staff's reliance on that connection in support of FIFO is misplaced. The Commission has determined further that smoothing costs of the nuclear fuel inventory through weighted average is preferable to the fluctuation of costs that would occur using FIFO.

B. Westinghouse Credits

It is agreed between UE and Staff that the traditional method for feeding back the Westinghouse credits received in settlement would be over the same period as the contract. This period was the initial core plus ten reloads. As part of its phase-in proposal, UE would amortize the credits already received over a two-year period. Staff witness Wilson proposes substantially the same result. Wilson's method of reaching the result is based upon generation and splitting the credits into two categories. His separation of the credits and treatment thereof is rather involved.

The Commission has determined Staff has unduly complicated the matter with regard to amortizing the Westinghouse credits while reaching a result similar to UE's. The Commission determines that UE's straightforward two-year amortization is the more appropriate method for feeding back the credits. The Commission believes a set time period for feeding back the credits is preferable to one based upon generation.

C. Westinghouse Nuclear Fuel Settlement

The Staff has made three recommendations in this case concerning the Westinghouse settlement agreement which have no revenue impact. Even though these recommendations have no revenue impact in this case, Staff proposes the Commission resolve these matters for future rate cases. These three issues are: (1) a credit against nuclear fuel costs of $30,550,000 based upon UE's tying of certain

Westinghouse credits to the operation of Callaway II; (2) a cap of $35 a pound on uranium purchased by UE from Western Nuclear and allocated to Callaway II; (3) that UE obtain from Westinghouse an accounting of the gross and net proceeds received by Westinghouse from its antitrust litigation and made a part of the UE settlement.

The three issues concern the failure of Westinghouse to honor its contract with UE for uranium and the subsequent settlement. As pointed out by Staff, the significant dates in this matter are: (1) September 7, 1975, when Westinghouse claimed it was excused from fulfilling its contract to supply uranium to UE; (2) October 7, 1978, the date the U.S. District Court ruled in a companion case that Westinghouse was not excused from performance of its uranium contracts, and subsequently, the court's ordering Westinghouse to supply UE with 2,007,000 pounds of uranium; (3) January 15, 1979, when UE entered into a long term contract with Western Nuclear for uranium; and (4) January 30, 1980, when UE and Westinghouse settled their contract dispute.

Staff contends UE should have gotten a better settlement from Westinghouse. Staff's primary objection to the settlement is UE's acceptance of a provision tying $77.3 million in credits to the completion and operation of Callaway II. Staff states the key issue is whether UE was prudent in conditioning the settlement credits on the construction and operation of Callaway Unit II. Staff contends UE should have received unconditional compensation for having to cover the loss of uranium allocated to Callaway II. Staff contends that although Westinghouse's obligation to UE for damages associated with Callaway II ceased to exist once Callaway II was canceled, UE still had damages because of the Western Nuclear contract. The $30,550,000 is based upon a calculation performed by Staff witness DeSalvo. Staff ties its proposed offset to the result of Callaway II litigation.

UE attacks Staff's $30,550,000 figure based upon Staff's change in position regarding the deficiencies in the settlement and the corresponding dollar amounts as determined by DeSalvo. When DeSalvo came up with his figure he based it on three separate deficiencies. In its brief Staff only based the $30 million figure on the Callaway II credits. Using DeSalvo's figures, UE contends that Staff's figure should now be $15.58 million.

UE contends further that no offset should be made since the evidence is that the credits received entirely cover the difference between the Western Nuclear contract and the Westinghouse contract. UE states it has no right to compensation for damages it did not incur, so it is due no compensation for Callaway II. The issue, as UE postulates, is whether the credits received totally compensate UE for the damages associated with the failure of Westinghouse to fulfil its contract.

The Commission has reviewed this rather detailed presentation of nonrevenue items. The Commission agrees with UE that the crux of this issue is whether the credits received from Westinghouse fully compensate UE for the higher costs of uranium in the Western Nuclear contracts. The issue of any damages from the cancellation of Callaway II appear moot. UE could not be compensated unless it was damaged. Since there were no damages associated with Callaway II, the Commission does not consider UE imprudent for not receiving compensation for those damages. The evidence in this case is that the value of the settlement plus certain concessions made by Western Nuclear completely offset the damages from the cancellation of the Westinghouse contract. (Exhibit C-115, Confidential). If this continues to be the case, there seems to be no basis for any further offset. If not, it will have to be presented at a later time.

Staff's second proposal is a cap of $35 on uranium allocated to Callaway II. This cap is proposed because of the higher price UE will be paying for uranium in the Western Nuclear contract. Staff contends UE should not have contracted on a long term basis with Western Nuclear at the height of the uranium market. This is not an issue in this case since no Western Nuclear fuel is used in the initial core.

This portion of Staff's nonrevenue proposal is discussed at length in relation to UE's decision to enter into a long term contract with Western Nuclear. UE contracted for uranium to be supplied over the period from 1984 to 1995. The contract is a requirements contract and UE must take delivery whether it needs the uranium or not. Staff contends this could lead to a substantial uranium inventory being held by UE.

The Commission does not believe it can resolve this issue in this case. The evidence raises questions as to whether UE was prudent in entering into a long term contract for nuclear fuel at the highest prices of uranium in history. The requirements provision of the contract make it even less advantageous to UE. The long term effect of the contract, though, cannot be foreseen at this time and the Commission does not want to prejudge this issue. The contract may eventually turn out to be favorable. The Commission has determined that no decision need be made in this case on a cap on the price of Western Nuclear uranium.

The final proposal of Staff is that UE obtain an accounting from Westinghouse of the payments received by Westinghouse for its antitrust litigation. The Commission considers this a reasonable request, since part of the settlement UE received from Westinghouse are payments based upon the antitrust litigation. The Commission considers it reasonable for UE to obtain an accounting of the proceeds received by Westinghouse in order for UE and the Commission to determine whether UE is receiving the portion as called for in the settlement agreement.

X. Total Fuel Costs

A. Callaway Availability Rate

In an ordinary rate case UE would utilize its SSP model to calculate total fuel costs based upon historical availability rates of fossil plants. Since there is no historical data for the Callaway Plant, the parties have developed availability rates based upon industry data. The availability rate of the Callaway Plant will be used to forecast the cost of nuclear fuel, and the forecast of fossil fuel will vary depending upon the rate adopted. Fossil fuel will be forecasted to generate remaining energy requirements. If Callaway is actually available a higher percentage of the time than the rate chosen, UE will use less fossil fuel and then save on fuel costs. Conversely, if Callaway is not available and is utilized less than the rate, UE will spend more on fossil fuel costs.

The availability rate is described by Staff witness Proctor as the amount or percentage of time the plant is expected to be available to generate power, taking into account both full and partial outages. Staff and UE calculate their respective availability rates in a similar manner. Both developed a percentage for full outages, which are scheduled and forced, and a percentage for partial outages. Partial outages are when the unit is available for service but due to some equipment or regulatory constraint it is not available for full output. Full outages are when the unit is completely out of service and no power is available from the unit. Staff's proposed availability rate is 77.57 percent, while UE's changed from 52.5 percent to 70 percent during the course of this case.

Staff based its calculation of the full outage rate on the data of 20 other nuclear plants. Staff witness Watkins developed a percentage for full outages, using the data found in the United States Nuclear Regulatory Commission publication NUREG-0020 (Gray Book). The Gray Book is a periodic publication put out by the NRC which contains statistical data on nuclear plants. The full outage rate as computed by Staff is 18.7 percent.

The Gray Book codes the various down times or outages for each nuclear plant. There are separate codes for maintenance and refueling. Watkins testified he only excluded those outages coded as refueling. Watkins calculated the full outage rate based upon the lifetime averages of each plant after determining a start date for each plant based upon when that plant would have met the Commission's in-service criteria.

UE in rebuttal testimony presented by witness Buchmeier obtained a full outage rate of 23.9 percent. To obtain this rate UE updated its data from its earlier prefiled testimony, partially based upon Staff's prepared testimony. To arrive at the full outage rate Buchmeier interpolated between the first and second year of operation of the sample plants to arrive at a median range of outages. Buchmeier also used the first full year outages of the sample plants to account for what he terms "plant immaturity". Buchmeier states that both his and Staff's data bases are flawed but that his calculations are more representative of the potential outages at Callaway during the first year of operation.

UE attacks Watkins' study on the basis he failed to take into account unit immaturity, he used lifetime averages for sample plants rather than the first two years, and he excluded certain maintenance outages because of his use of the codes in the Gray Book. These problems with Staff's data, UE asserts, cause Staff's full outage rate to be understated and thus, its availability rate to be overstated.

The Commission has reviewed the data presented by UE and Staff and the supporting testimony. The Commission is aware of the flaws in each study and so must weigh their inherent problems in determining what is the proper full outage rate for the Callaway Plant. The Commission is not convinced that unit immaturity exists and, even if it does exist, whether UE made the proper calculation for that factor. The Commission, though, finds that Staff's use of the Gray Book codes is the most serious flaw in the data presented. This flaw leads the Commission to accept UE's full outage rate. Staff failed to review its data to remove the maintenance outages that extended refueling. This caused Staff to understate its full outage rate since there were significant maintenance-related outages which were coded in the Gray Book as refueling. The number of weeks for some of those outages were obviously due to maintenance in addition to refueling. Staff's failure to adjust for these maintenance outages seriously undermines the results of its calculations and prevents the Commission from adopting Staff's full outage rate.

The disagreement between UE and Staff over the partial outage rate is similar to their disagreement over the full outage rate. UE attacks Staff's data base, and Staff attacks UE's results because they are not arrived at through an independent study but are dependent on other assumptions.

Staff's partial outage rate is 4.6 percent and was developed from a data base using National Electric Reliability Council (NERC) data. Staff used data from the life of sample plants, where available, and used the full year of partial outages from the year the plant met the Commission's in-service criteria. Staff witness Proctor, who did the study, testified that individual plant data was not available from NERC so he used total group data. He stated that there were problems with the data but that it was the only data available. Proctor testified he thought this was the same data base used by UE.

Buchmeier provided the NERC data to Staff but he then looked at individual plant data if he could find it. Buchmeier used data obtained from an EPRI data base. Even though Buchmeier used the EPRI data, he calculated his partial outage rate using assumptions concerning Callaway's capacity factor and utilization rate rather than working independently with the EPRI data. The capacity factor, as stated by Buchmeier, is a measure of the actual output of a unit as a percent of the output possible if no outages occur; and the utilization factor is the ratio of capacity factor to equivalent availability rate.

Buchmeier arrived at his partial outage rate by comparing the utilization factor derived from Staff's figures to values calculated from industry sources. Buchmeier attributes the difference between the EPRI data and Staff's data to additional partial outages not in the NERC data. The difference occurred because the NERC data did not account for (1) unit ramping, (2) core physics, (3) water temperatures, and (4) inadequate reporting of load reductions. These factors, Buchmeier asserts, mean Staff's partial outage rate is understated.

Proctor states that the calculations and application of the partial outage rate to service hours should be accomplished without any assumptions regarding the level chosen for service hours. He states that Buchmeier's calculations are dependent on assumptions concerning the proper level for both the capacity factor and service factor (utilization factor). The use of different assumptions would change Buchmeier's partial outage rate. Proctor states his calculations are independent of these assumptions and are consistent with his data base and this is the proper method for doing the study.

As with the data used by Staff and UE for full outages, the data used for partial outages is not perfect. There are admitted gaps in the data used by Staff which are not completely rectified in UE's data. UE has chosen to work outside of the data to reach its partial outage percentage. This may have some intuitive appeal, but the Commission does not believe the partial outage rate should fluctuate based upon assumptions of capacity factors and utilization rate. These factors are outside the data base. Staff's analysis is more statistically sound than UE's on that basis, even with the admitted data problems. The Commission finds Staff's 4.6 percent partial outage rate is the more reasonable on that basis.

Proctor testified that if the Commission adopted UE's full outage rate and Staff's partial outage rate, the resulting availability rate would be 72.6 percent. The Commission has adopted these positions and finds that 72.6 percent is the proper availability rate for Callaway.

B. <u>Callaway Rating</u>

This subissue concerns the electrical rating to be used for the Callaway Plant as a component of the total fuel costs as produced by the SSP model. The disagreement between Staff and UE is whether Callaway should be rated as an 1150 megawatt plant or as an 1120 megawatt plant. The Callaway Plant was designed to operate at 1150 megawatts. The NRC has licensed the Callaway Plant to operate at

1120 megawatts. The rating in the SSP model will determine how much fossil fuel ratepayers will have to pay for to operate UE's system.

UE's position is basically that it has the NRC license to operate at 1120 megawatts and cannot operate any higher. Since this is the license rating, that is the rating that should be used in the SSP model. UE s states it always intended to ask for the 1120 megawatt rating initially, even though it used the 1150 megawatt rating in discussing the Callaway Plant, both at the certification proceedings in 1974 and subsequently.

UE stated it does intend to apply for the 1150 megawatt rating from the NRC at some time in the future. Originally it stated it expected to wait five years to apply. At hearing, Schnell testified that this may have been conservative and UE could seek the uprating of the Callaway Plant sooner than five years.

Staff has attacked the use of the 1120 megawatt rating on basically two grounds. First, Staff argues that UE has consistently utilized an 1150 megawatt plant rating in prior regulatory proceedings before the Commission, but now it is only licensed to be a 1120 megawatt plant. Second, Staff argues that ratepayers should not have to pay the costs of an 1150 megawatt plant which is only licensed to generate 1120 megawatts in power. In its brief Staff emphasizes the second ground as the primary reason for opposing the use of the 1120 megawatt rating. The cost of the fossil fuel to make up the 30 megawatts difference in power will be borne by the ratepayers if the 1120 megawatt rating is used. Staff feels the ratepayers should not have to pay for this fossil fuel when the Callaway Plant should have been capable of producing more power.

The Commission views this particular issue in the limited context of the proper rating to be used in the SSP model. The Commission has determined that UE is only licensed to operate at 1120 megawatts and that is the rating which should be used in the SSP model. The Commission is concerned about the testimony of Schnell that UE would wait five years to seek an uprating. This seems to be a very conservative approach and the Commission will review what it considers to be the proper rating of the Callaway Plant in the next rate case based upon UE's efforts to uprate its license for Callaway.

The Commission is of the opinion that UE promised the customers an 1150 megawatt nuclear power plant and it should achieve that rating as soon as possible. As stated earlier, the Commission is adopting the 1120 megawatt rating only for the SSP model and this in no way indicates an acceptance that 1120 megawatts is the appropriate rating to be used for Callaway on all issues.

C. Forecasted Fossil Fuel Costs

This issue was originally to be resolved in Phase II of this case and in the order in Case No. ER-84-168. By agreement, the issue of forecasted fuel costs was omitted from Case No. ER-84-168 and held over for resolution in this case. The agreement indicates UE is obligated to refund any overcollection with interest, and cannot recover for any deficiency. This matter was addressed in the true-up proceedings held on March 7, 1985. A stipulation and agreement was entered into by the parties which resolved this issue. The true-up stipulation is set out separately in this order. The Commission finds that the agreement between the parties concerning the amount stipulated to for forecasted fuel costs is appropriate and that the method of collecting the money subject to refund is also appropriate, and therefore will adopt the stipulation and agreement between the parties on this issue.

XI. True-Up

At the true-up hearing, the parties presented a Stipulation and Agreement resolving all true-up issues. The Stipulation and Agreement as amended by the parties is set forth below:

STIPULATION AND AGREEMENT FOR
TRUE-UP HEARING

I. The parties hereto agree that the amounts allowed in rate base for the true-up in this proceeding, and the amounts allowed pursuant to the agreement regarding forecast fuel costs, shall be as set forth in the Staff testimony filed on February 26, 1985, subject to the following modifications and explanations:

1. The Company shall be allowed to accrue AFUDC on the $17,126,000 (Missouri jurisdictional) not audited and thereby disallowed by Staff. To the extent this disallowed amount is allowed in rate base in a subsequent rate case, the associated AFUDC shall also be included in rate base.

2. The nuclear fuel inventory shall be $45,518,000 (Missouri jurisdictional).

3. $721,000 (Missouri jurisdictional), of purchased power and interchange sales shall be shifted from the November "base" fossil fuel costs to the fuel cost component subject to refund. Therefore, the amount of fuel cost subject to refund will be $10,598,000 or .053¢/KWH.

4. The dollar amounts in items 2 and 3 above were calculated assuming a capacity factor for the Callaway Plant of 77.5% and Staff's nuclear fuel costs and treatment of Westinghouse fuel credits. If the Commission adopts the Company position on these items, the above figures would be revised accordingly.

II. The capitalization and costs of debt and preferred stock shall be as follows:

	Capitalization Ratio	Cost
Long-term debt	50.88%	10.22%
Preferred stock	11.75	9.65
Common equity	37.37	
	100.00%	

III. The terms of this agreement are for settlement only, and do not represent an agreement as to underlying methodologies or principles by any party hereto. The parties to this stipulation shall not be prejudiced, bound by, or in any way affected by the terms of this stipulation and agreement in any other proceeding.

Respectfully submitted,

STAFF OF THE MISSOURI
PUBLIC SERVICE COMMISSION

By /s/ William C. Harrelson

OFFICE OF THE PUBLIC COUNSEL

By /s/ Richard W. French

UNION ELECTRIC COMPANY

By /s/ Paul A. Agathen

March 7, 1985

The Commission determines that the Stipulation and Agreement of the parties is reasonable and should be adopted.

XII. Rate Of Return

The Commission determines that the agreed-to cost of debt, cost of preferred stock and capital structure set forth in the True-Up Stipulation are reasonable. Therefore, the issue to be addressed herein is the appropriate return on equity for UE reflecting the in-service status of the Callaway plant.

UE is proposing a return on equity of 15.62 percent assuming proper recognition of all Callaway costs and the adoption of a phase-in substantially similar to the plan filed by UE.

Staff recommends return on equity ranging from 15.00 to 15.75 percent. Staff witness Parcell recommended a range of 15.5 to 16.4 percent for the Phase II increase. Staff's recommendation for return on equity once Callaway is in service is based on an adjustment to Mr. Parcell's short-term and long-term discounted cash flow (DCF) studies. The adjustment was calculated by Staff witness Ileo and is an attempt to quantify the reduced risk perceived by investors once a nuclear plant goes into service.

Dr. Ileo analyzed 98 electric utilities utilizing value line 1984 data. Value line categorized these companies into three distinct groups: group 1 is composed of electric utilities without nuclear plants; group 2 is composed of those electric utilities with only operating nuclear plants; and group 3 is composed of electric utilities which are constructing nuclear plants. Dr. Ileo further segregated group 3 into group 3A and group 3B. Group 3B is composed of those companies which because of troubled nuclear construction programs have suspended dividend payments or greatly reduced such dividend payments and/or the likelihood of such event appears significant.

Dr. Ileo's analysis reveals that group 1 has the highest market to book ratio while group 3B has the lowest. Group 3B had a lower market to book ratio than 3A. However, due to the dividend problems associated with construction programs, Dr. Ileo has not considered 3B as comparable to UE. Dr. Ileo's results showed a variance in the spot DCF as well as a five-year DCF for group 2 and group 3A. Dr. Ileo concludes the data suggests financial markets have placed a risk premium on nuclear power and that the risk is perceived as being greater for electric utilities with nuclear power under construction than utilities which have made the transition to successful operation.

In addition to the comparative analysis, a statistical analysis was performed by Dr. Ileo to determine if there were factors responsible for the risk perceptions of the market other than the association with nuclear power. Dr. Ileo concluded that while some aspects of utility operation have an influence on risk perception and market performance their significance is generally less than that which could be attributed to the mere fact that a utility is involved with nuclear power.

In addition the specific type of involvement in nuclear power appears to be important since the results of the statistical analysis indicate that the reduction in risk perceived by the market when a nuclear project makes the transition from construction to successful operation is equivalent to a reduction in a market determined cost of equity of 54 basis points to 250 basis points depending on whether a long or a short-run DCF analysis is adopted. Dr. Ileo compared the spot DCF, the five-year DCF and the market to book ratios for the three groups. The spot DCF was based on the May-June value line data. With respect to the spot DCF, the average figures indicated a differential in expected return of 57 basis points for group 2 over group 1 and a differential of 116 basis points for group 3A over group 2. The differential of 116 basis points was statistically significant at the 95 percent confidence level. This was not true for the 57 basis point differential for group 2 over group 1.

Regarding the five-year DCF averages, the differential was 35 basis points for group 3A over group 2 and 54 basis points for group 2 over group 1. However, Dr. Ileo noted that the variances were not statistically significant at the 95 percent confidence level.

Market to book ratios were statistically significant at the 95 percent confidence level among all groups except between groups 1 and 2.

Dr. Ileo attempted to determine other factors that might explain the observations by performing various regression analyses. Dr. Ileo analyzed the 91 electric utilities contained in the value line survey excluding group 3B using both linear and non-linear regression analyses. Since the non-linear regression models produced poor results they were not pursued.

The results of Dr. Ileo's linear regression led him to conclude that the group designation for a company had a statistically significant impact on the five-year DCF analysis and market to book ratio results. However, Dr. Ileo concludes that this group designation did not provide the only explanation of variations of market performance measures. Dr. Ileo found that the independent variables associated with bond rating, percent of construction work in progress, and actual earned returns, also had a significant impact.

Dr. Ileo then performed a step-wise linear regression analysis for all 91 companies individually as well as in groups. This was performed to determine which set of independent variables taken in all possible combinations had the most explanatory power with respect to the dependent variables, spot DCF return, five-year DCF return and market to book ratios. Dr. Ileo observed that the group designation decreased market to book ratio by 6.402 percentage points as a utility makes the transition from one group to another. Further, Dr. Ileo determined that the market to book ratio decreased by 2.9165 percentage points for each unit of downgrading in the company's bonds. Additionally, Dr. Ileo observed that the market to book ratio increased by .143 percentage points for each percentage point increase in a utility's percentage of electric revenues. Finally, market to book ratios decreased by .199 percentage points for each percentage point in a utility's construction work in progress percentage.

Utilizing this model for the Union Electric Company, Dr. Ileo found that the predicted market to book ratio for UE would be 79.1 percent. This compares to UE's actual market to book ratio of 79.1 percent. Based on a further utilization of this model Dr. Ileo concluded that when UE moves to group 2 it should experience a vast reduction in its CWIP balance, an increased bond rating, and UE's market to book ratio would rise to 92.8 percent.

Dr. Ileo then performed a cost of equity calculation for UE utilizing this predicted market to book ratio of 92.8 percent. The resulting spot DCF calculation revealed a return of approximately 15.8 percent for UE in 1984 had Callaway been in service. This is compared to the calculated spot cost of equity for UE of 18.2 percent. From this Dr. Ileo concluded that the spot cost of equity to UE would have been 240 basis points lower had Callaway been in service in May of 1984.

Dr. Ileo's analysis discovered four statistically significant models for group 2 companies. The four models were used to analyze the company. Dr. Ileo made the following assumptions: that Callaway would be successfully placed in service and make the transition from group 3A to group 2; that the Commission would adopt Staff's disallowances and phase-in proposals; an authorized rate of return of 15.62 percent, and financial results for the over-all company as estimated by Staff witness Skirpan; that certain operational and structural characteristics conform to the forecasts made by UE; and that UE's bonds would either be upgraded or remain at their present level. The model which predicts five-year DCF estimated a range of 12.43 percent to 15.95 percent. These predictions were within a 95 percent confidence level. Dr. Ileo concluded that although the lower bound is within the realm of statistical possibility it is not realistically consistent with the economic and financial theory and therefore he gave primary weight to the upper end of the range of 14.19 to 15.95 percent. Dr. Ileo noted that the result is consistent with the two earlier observations that the average five-year DCF for group 2 companies is 14.90 percent, which is 35 percent basis points lower than for group 3A companies and that a shift from group 3A to group 2 status decreases the five-year DCF by 54 basis points.

Dr. Ileo concluded that his model 17 provided the best estimate of UE's market to book ratio since model 17 had the highest R^2 of the three models and because it contained bond rating as a significant explanatory variable. Utilizing this model to estimate UE's market to book ratio once Callaway becomes operational, Dr. Ileo assumed Mr. Skirpan's forecasted 1985 book value of UE, the value line growth rate of 4.5 percent and a $1.80 dividend for 1985, which is consistent with value line's growth rate. This analysis resulted in an expected spot DCF value of 15.69 percent. Consequently, Dr. Ileo concluded that the placement of Callaway into successful operation would reduce the spot DCF return for UE by 250 basis points.

Dr. Ileo compared this result with his earlier findings and concluded that an adjustment for successful operations should be greater for a spot DCF than for a DCF which relies on data for a longer period. The earlier findings showed that (1) the May-June, 1984 average spot DCF differential between groups 2 and 3A was 116 basis points and statistically significant with 95 percent confidence; the August, 1984 average spot DCF differential between groups 2 and 3A was 121 basis points and the spot DCF for the 91 companies based on the step-wise regression results resulted in a 240 basis point differential.

Based on Dr. Ileo's findings, Mr. Parcell utilized a 35 to 54 basis point adjustment to his long-term DCF finding and 121 to 250 basis points to his short-term finding. Mr. Parcell used a ratio analysis and an average of eight possible costs of equity to arrive at his recommended adjusted equity return.

UE's rebuttal testimony raised several errors which are contained in Dr. Ileo's studies. In surrebuttal, Dr. Ileo corrected the data set and utilized Mr. Skirpan's revised forecasts based on UE witness Brandt's accounting position. Based on these changes, Dr. Ileo revised his regression analysis which resulted in a larger reduction in UE's cost of equity due to placing Callaway in service than were contained in his original results.

In the Commission's opinion the evidence establishes that an electric company which has a nuclear plant under construction should be perceived as having greater risks than a company which has completed construction and is successfully operating a nuclear plant. UE concedes that this is the case in its brief.

In the Commission's Phase II Report and Order in Case No. ER-84-168, the Commission authorized a return on equity of 16.1 percent. The Commission determines that a downward adjustment of the previously authorized 16.1 percent return should be made to reflect reduced risks associated with successful Callaway operation.

In this case the Commission has included all prudent Callaway investment in rate base. In addition, the Commission has essentially adopted a fixed year phase-in plan in order to reduce uncertainties and perceived risks related to Callaway recovery.

In light of the foregoing, the Commission determines that UE's recommended return on equity of 15.62 percent should be adopted in this case. This results in an overall return of 12.17 percent.

XIII. Fair Value Rate Base

The Commission concludes that UE's fair value rate base shall be the trended original cost less depreciation of UE's Missouri jurisdictional electric properties which is $4,055,088,934 without Callaway I. Adding the original cost of the Missouri jurisdictional portion of UE's investment in Callaway I of $2,013,361,000, results in a fair value rate base of $6,136,030,934.

XIV. Revenue Requirement

Based on the findings and conclusions herein, UE's total revenue requirement is $1,440,875,000, requiring increased revenues of $454,809,000.

XV. Financial Impact

In arriving at the revenue requirement found reasonable herein, the Commission has reviewed its effect on UE's financial condition. The record contains financial projections for UE assuming Staff's, PC's and UE's positions in this case. Exhibit Nos. C-304, C-305 and C-308 were provided to the Commission at the Commission's request by Staff witness Skirpan. These exhibits show financial projections for 1985-1989 assuming the Commission's findings in this case under three scenarios related to accounting and tax treatment for Callaway disallowances.

The Commission determines that UE will be in a strong cash flow position, will be able to maintain adequate interest coverages and will be in a position to earn its authorized return during the phase-in period. Thus, UE should be able to attract capital and preserve its financial integrity.

XVI. Rate Phase-In Proposals

UE, Staff and Public Counsel have submitted various methods for phasing in the rate increase adopted in this case.

UE's phase-in plan is based on the following proposals:

(1) Deferred return on equity on a portion of Callaway rate base.

(2) Accelerated amortization of certain Callaway-related deferred income taxes.

(3) Accelerated amortization of Westinghouse nuclear fuel credits.

(4) Substitution of the units of production depreciation for straight line depreciation during the first three years of Callaway's commercial operation.

UE proposes that the increase be spread over five years with a first year increase of 25 percent followed by increases of approximately eight percent for the subsequent four years. Because of the Commission's order allowing the Phase II increase, the eight percent increase over the last four years would be adjusted.

The deferred equity would continue to be recovered for two years after the implementation of the five proposed increases.

UE proposes that the Commission approve tariff sheets authorizing the first year increase as well as the remaining increases under the plan which would automatically take effect in the succeeding years of the phase-in.

Staff recommends that the phase-in be implemented based on the following proposals:

1. The percentage of Callaway capacity cost which would be included in each year of the phase-in should be based on the cost associated with the Callaway capacity required to meet a levelized reserve margin of 21.37 percent plus the fuel savings generated by having the total Callaway plant available to meet load.

2. The length of the phase-in period should not be determined in this case, rather the percentage of Callaway capacity costs included in each year should be determined on an annual basis depending on the actual growth in UE's peak demand.

3. The deferred earnings associated with the first year of phase-in should be put into rate base over the next seven years in equal increments and accrue a carrying cost at the authorized return on equity.

4. The determination of UE's capability to meet peak demand should be based on a total capacity of 8,189 megawatts. This includes ratings of 960 megawatts at the Sioux plant, 2,372 megawatts at the Labadie plant, 1,206 megawatts at the Rush Island plant, 71 megawatts at the Ashley plant, and 1,150 megawatts at the Callaway plant.

Staff's proposal assumes that 38.5 percent of Callaway-related revenue requirement would be recovered the first year of the phase-in which would be equal to a 9.52 percent rate increase.

If Public Counsel prevails on his rate base proposal, then Public Counsel recommends either phasing in the increase in three equal amounts over a three-year period or allowing the entire increase in one year but rapidly amortizing the deferred taxes over a two-year period. Either approach would keep Callaway-related increases in the 10 to 13 percent range.

If the Commission does not accept Public Counsel's rate base proposal, Public Counsel recommends that UE begin earning a cash return on 10 percent of Callaway investment in 1985 and on further portions of Callaway investment in subsequent years. This proposal produces an increase of 15 percent in the first year with increases in the 10 percent range in subsequent years.

Alternatively, Public Counsel recommends accelerated amortization of deferred taxes and/or the Westinghouse settlement credits to reduce the first year increase.

It is Public Counsel's position that any annual increase remain in the 10 percent range. Public Counsel contends that 10 percent is the upper limit that a ratepayer could afford to pay in any one year.

The Commission has carefully reviewed the record and arguments pertaining to the various phase-in plans and finds that the phase-in shall be adopted as follows:

1. The phase-in shall be over a period of 8 years; 6 years of rate increases followed by 2 years of recovery of deferred equity.

2. The increase in year one shall be 14 percent followed by an increase of 10 percentage in year 2. The increase in years 3, 4, 5 and 6 shall be 7.29 percent.

3. The phase-in shall be accomplished by deferring equity return on Callaway rate base. Recovery of deferred equity shall commence in year 5 and continue through year 8.

4. Callaway-related deferred income taxes shall be amortized over a two-year period.

5. Westinghouse nuclear fuel credits shall be amortized over a two-year period.

6. Tariff sheets implementing the phase-in will automatically take effect in succeeding years.

7. Deferred equity will be fully recovered by the end of the eighth year requiring a 12.49 percent decrease in rates.

The Commission has rejected a first-year increase of 25 percent because of ratepayer impact. UE presented no justification for its 25 percent first-year proposal.

The Commission notes that an approximate one percent increase subject to refund has been authorized for 1985, reflecting forecasted fuel costs. Adding the one percent to the phase-in results in a 15 percent increase for 1985.

The Commission believes that an upper limit of 15 percent is appropriate for 1985. Greater increases in the first two years of the phase-in will result in a lower amount of deferred equity in later years than if the first year increase was in the 10 percent range.

The Commission determines that a definite phase-in period and the authorization of tariff sheets which would automatically take effect is appropriate for three reasons: (1) ratepayers will be able to plan their budgets for electric costs and alter their consumption patterns accordingly; (2) UE will have an incentive to postpone rate filings for several years; and (3) UE and the investment community will have an assurance that the phase-in plan is in effect, thereby eliminating any perceived risk or uncertainties regarding the ultimate inclusion in rates of the allowed Callaway capital costs and deferred equity. The elimination of uncertainties will enable UE to obtain a lower cost of capital benefitting both shareholders and ratepayers.

The Commission determines that an eight-year phase-in is appropriate as it is generally consistent with Staff's theory of achieving the levelized reserve margin. The levelized reserve calculation is based on the minimum reserve recommended by the Mid-America Interpool Network Regional Reliability Council as UE has applied that criteria to their own system. The use of the 18 percent as UE's long-range planning minimum reserve margin is appropriate. The levelized reserve of 21.37 percent is in excess of the 18 percent minimum reserve margin since the levelized reserve is the determination of the average level of reserves for each type of capacity. The average level of reserves for each type of capacity is based on the 18 percent minimum reserve requirement as well as the load growth of peak demand over a 12-year period. Because of the size of the Callaway unit, UE is bringing capacity on line which is in excess of what is required to meet load and reliability criteria. Based on the UE load forecast and Staff's calculation of the levelized reserve margin, UE should achieve a levelized reserve margin by the end of the phase-in period. Even though Staff's total capability includes 1,150 megawatts for Callaway rather than 1,120 and 71 megawatts for the Ashley plant, the Commission still believes that eight years is appropriate because of uncertainties regarding UE's load forecast.

Based on the foregoing, the Commission determines that Staff's levelized reserve margin theory is an appropriate basis for determining the length of the phase-in period since it assumes that revenues should follow the benefits accruing to the ratepayers. This principle is based on the traditional used and useful theory utilized in utility ratemaking.

The Commission determines that the phase-in plan adopted herein meets the requirements of the 1984 enactment of the General Assembly:

> 393.155. If, after hearing, the Commission determines that any electrical corporation should be allowed a total increase in revenue that is primarily due to an unusually large increase in the corporation's rate base, the commission, in its discretion, need not allow the full amount of such increase to take effect at one time, but may instead phase-in such increase over a reasonable number of years. Any such phase-in shall allow the electrical corporation to recover the revenue which would have been allowed in the absence of a phase-in and shall make a just and reasonable adjustment thereto to reflect the fact that recovery of a part of such revenue is deferred to future years. In order to implement the phase-in the commission may, in its discretion, approve tariff schedules which will take effect from time to time after the phase-in is initially approved.

In compliance with the statute, the Commission has allowed a return on deferred equity which results in a total revenue increase over the period of the phase-in of $652,382,000.

XVII. Intervenor Proposals

A. State of Missouri

The State of Missouri proposes a rate "cap" such that the maximum rate increase for any individual account would be not more than five percent above the system average increase. Staff and UE oppose the State's recommendation, and further contend that this is a rate design proposal and should have been submitted in Phase II of these proceedings.

The Commission also considers this to be a rate design issue. If it is not a rate design issue then it is a proposal that any costs in excess of the five percent cap simply not be recovered.

The Commission concludes that the State of Missouri's proposal should be rejected. The Commission has considered the impact of all rate increases authorized in this case and has addressed them in both the phase-in and the rate design portion of this order.

B. Missouri Public Industry Research Group

MoPIRG proposes an excess capacity adjustment to reflect additional excess capacity which would exist had UE management pursued conservation and load management.

Since the record contains no basis for such an adjustment, the Commission concludes that MoPIRG's proposal should be denied. The Commission notes that under cross-examination Mr. Cornelius stated that after reviewing the current load forecast he estimated the need for more generating capacity between the years 1993 and 1995. Based on the evidence concerning the accuracy of UE's load forecasts the high capital cost of base load generating facilities, and the possibilities of conservation and co-generation, the Commission will be extremely interested in how conservation efforts are addressed by UE in Docket No. EO-84-105.

C. Electric Ratepayers Protection Project and Missouri Coalition for the Environment

The Missouri Coalition for the Environment and Electric Ratepayers Protection Project (Coalition) did not participate in the hearings of this matter other than to appear on the last day of the hearing and offer the entire record of Case No. EO-80-57, which offer was denied by the Hearing Examiner.

In its brief, Coalition provides several alternate recommendations. Coalition recommends that the entire cost of Callaway be excluded from rate base; that if some of the initial costs are allowed, a large portion of the cost should not be allowed because they were imprudently incurred; that the Callaway plant is in fact economically not useful and constitutes excess capacity; that much of the cost overruns, especially financing costs, are attributable to UE directly and therefore should not be recoverable in rate base.

The Commission has considered the Coalition's arguments in making its determination concerning Callaway rate base inclusion. Coalition's excess capacity adjustment is not supported by the record. The Commission's determination with regard to Callaway rate base inclusion have been decreased in Section III-A through C above.

XVIII. Rate Design

This proceeding offers the Commission an opportunity to make a comprehensive assessment of the allocation of the total revenue requirements of Union Electric Company (UE) to its customer classes and within those classes. The Commission has not considered the overall design of UE's rates within a proceeding since Case No. EO-78-163. Even in Case No. EO-78-163 the parties stipulated to the issues and no decision was made by the Commission concerning the rate design or ratemaking principles underlying the stipulation. Subsequent rate proceedings have dealt with some specific part of UE's rates, but none addresses the validity of the principles upon which the current rate design is founded.

The parties participating in the rate design portion of these proceedings are: Union Electric Company (UE), Missouri Public Service Commission Staff (Staff), Office of Public Counsel (PC), Industrial Intervenors (Industrials), Dundee Cement Company (Dundee), State of Missouri (State), Jefferson City, et al. (Cities), City of Cape Girardeau, City of Kirksville, City of St. Peters, Missouri Retailers Association (Retailers), Metropolitan St. Louis Sewer District (MSD), Laclede Gas Company (Laclede), Missouri LP Gas Association and Missouri Limestone Producers Association. Hearings were held involving the rate design issue from September 10 through September 14, 1984. The parties submitted initial briefs and reply briefs setting out their positions on the issues involved.

The parties to this proceeding have directly addressed and made an issue of the proper cost of service method for assigning the total revenue requirement to the various classes and within those classes. In order to perform a class cost of service study, a party must first functionalize costs into cost categories. There is uniform agreement that these categories, generally, are: (1) production, (2) transmission, (3) distribution, and (4) other costs. These functionalized costs are then classified by each party as to the nature of their origin. UE, Industrials and Retailers use "fixed" and "variable" classifications, while Staff uses "capacity" and "running" costs classifications. Each party then develops allocation factors to divide the costs among the customer classes. These allocation factors are used to allocate those costs which cannot be directly assigned to a particular customer class. It is the allocation factors which generate the controversy.

The parties are in fairly uniform agreement that the proper method chosen to allocate costs should assign costs based upon cost causation as closely as practical. The parties here present two basic theories concerning what causes costs and how to assign those costs. The two approaches of the parties separate over the issue of whether capacity is built to meet system peak demand or total system demand. Staff and PC support the theory that the need for generating capacity is caused by total system demand. UE, Industrials, Dundee and MSD support the principle that generating capacity is caused primarily by system peak demand. Retailers agree with Staff and PC on the causation issue, but reject Staff and PC's method of allocating costs. Staff, PC, UE, Industrials and Retailers have presented cost of service studies for allocating the total revenue requirements among the customer classes.

Although the parties have approached the allocation of cost to the classes on a cost causation basis, there are other influences which affect the ultimate rates to be charged individual customers. The Commission agrees that allocating the costs of providing service to the classes and customers who cause these costs is the basic function of the rate design of a public utility company. The Commission, though, is also aware of other influences which affect the ultimate decision of what price a customer should pay for electric service. The straight assignment of costs to customers based upon any allocation method chosen by the Commission will be tempered by attempts to ensure the efficient use of the service and social policies regarding use of the service.

Rate design in this case involves two concerns. The first concern is the impact rate design will have upon the various classes where any change is made in the method of allocation. The other concern is that the rate design adopted will be the method by which the substantial increase in rates caused by the Callaway Plant will be allocated. All parties have addressed rate design from the Callaway perspective. Because rate design in this case involves the allocation of the production costs of the Callaway Plant, the major focus of all arguments concerning the proper method to use is upon production costs. The Commission will address itself to production costs first and then to the other functionalized costs.

A. Production Costs

1. Union Electric

UE performed eleven cost of service studies for this case. UE, though, does not propose any of the studies as the proper method for allocating the costs of the Callaway Plant. UE has proposed that the Commission allocate the revenue requirement determined in this case among the various customer classes on an equal percentage basis except for Lighting. UE proposes the Commission maintain the current rate design because of the magnitude of the increase requested.

All but one of the cost of service studies performed by UE are coincident peak (CP) methods. These methods are based upon the underlying principle that the Company's capacity requirements are determined by peak demand. To allocate costs on a causation basis, UE contends, one must look both at the amount of capacity needed to meet the system peak and the amount of energy needed to meet the system energy needs. UE's position is that capacity costs are fixed and are related to demand. These costs do not change with kilowatt hour consumption. Variable costs are those associated with fuel costs (energy) and do vary with kilowatt hour consumption. UE contends that fixed production capacity should be allocated on a demand basis and not by a kwh or variable basis.

UE contends that the coincident peak method of allocation places the cost of additional capacity on the customers causing increased peak demand. Offpeak customers do not cause the additional capacity, but in fact make the system more efficient by using capacity during nonpeak periods, thus increasing UE's load factor. UE contends these offpeak customers benefit the system by increasing the load factor of the system and thereby reducing overall costs. Since these offpeak customers do not cause additional capacity, they should not be allocated costs for their offpeak use. UE views its system as having fixed capacity; any new capacity is constructed to meet peak use and peak users should bear the cost of its construction.

2. Staff

Staff developed its own cost of service study for this case based upon UE's total revenue request. Staff used similar functionalized costs to those used by UE in its cost of service study, but classified those costs differently. Staff then developed its allocation factors to support its concept of the causation of the costs. Staff's position is that production capacity costs are caused by the total demand placed on the system. The total demand on the system varies from hour to hour throughout the year. The generating units are categorized as base load, intermediate and peak. The utilization (mix) of these different types of generating units will vary throughout the year in relation to such factors as hourly system demand, unit availability, incremental running costs of available units, and the availability of power on UE's interconnect system. Staff contends that as the mix varies, so do total costs vary.

Staff's cost of service study is based upon these variations of plant mix and customer usage throughout the year. It asserts the theoretically most correct approach to designing rates is based on this condition and is a method that determines the production costs of meeting system demand in each hour of the year. Thus the method should create 8,760 power pools to be allocated to customer classes based upon their use of the system during the hourly pools. This method is described as a time-of-use (TOU) method. Staff states, though, that there is insufficient load data to determine hourly demand for the UE system. Staff has thus proposed a TOU/average-and-peak (AP) method which it considers most closely approximates the preferable hourly TOU method. The AP method allocates the monthly production (capacity and running) costs to the classes based upon the class contribution to system average and to system peak demands. Production capacity costs related to average demand were allocated to classes based on their monthly contribution to energy measured with losses, and production capacity costs related to peak demand were allocated to classes based upon their monthly contribution to coincidental peak demand. The separation between average and peak demand was determined by use of a monthly loading factor for each power source (plant). Average demand was determined by multiplying the monthly plant loading factor times the monthly capacity costs. This figure was then subtracted from total costs to give the peak demand figure.

Staff developed a TOU production costing model to simulate operations of the UE system. Staff's production costing model was then used to allocate production capacity and running costs to the months. Staff then allocated the monthly costs to the classes through the AP method, since hourly load data was not available for a TOU allocation. Staff contends the AP method most closely matches the TOU hourly method. Underlying Staff's cost of service study are the principles of cost causation Staff feels are correct. Staff states the CP methods answer the wrong question concerning production capacity costs. The question is not the timing of future capacity additions and megawatt amount of those additions, but rather the responsibility of each customer class for the causation of the utility's embedded production capacity costs. The proper method for answering the question is to determine how UE's power sources (plants) are utilized by the classes. Staff asserts its TOU/AP method accomplishes this goal.

Staff bases its position on the premise that capacity utilization throughout the year is the proper method to allocate costs. It has classified production costs as capacity costs and running costs. Capacity costs are the replacement costs for each source of supply (plants); running costs are fuel and variable operating and maintenance costs. Staff's method views the UE system from a standpoint of what types and how much capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year.

3. Public Counsel

The Office of Public Counsel (PC) presented a cost of service study which allocates costs based upon its view of their causation. PC expressed a position similar to Staff's with regard to method of allocation of production costs. PC rejects the peak demand, after the fact view utilized by the CP method. PC asserts that production capacity is planned and installed by first preparing a load forecast and then determining mix of generating units that minimize costs of projected load.

A utility's first concern is system reliability. PC asserts the combustion turbine is the cheapest, most reliable form of production capacity for ensuring system reliability. The combustion turbines, though, are not designed to run full-time. Since a company's secondary planning goal is minimization of total costs, it will build intermediate and base load plants if they reduce overall costs.

To allocate the costs under its cost of service study PC disaggregated total fixed capacity costs into energy and demand components by examining the fixed costs associated with base load and peaker plants. PC then obtained energy and demand costs for each month and then allocated those costs for classes through an energy allocation and the July and August coincident peaks. PC asserts its method is a refinement of the AP method of allocating energy costs. PC's position is that only a portion of production capital costs is demand-related. The remainder is justified by the expected consumption of electrical energy which justifies the construction of base load plants.

4. Industrials

The Industrials propose the Commission adopt a 2CP method for allocating production capacity to the classes. This method uses the two highest peaks on UE's system for allocating costs among the classes. The method is based upon the principle that the peak responsibility theory accurately reflects the causation of UE's capacity costs. Industrials contend, as did UE, that capacity costs do not vary with output and should be regarded as demand-related. Production capacity, once installed, is fixed and not variable. Industrials contend there is no real-world relationship between either total capacity or offpeak capacity use and capacity investment. Industrials contend further that all empirical evidence and testimony of UE's witnesses indicate UE only constructs new production capacity to meet system peaks. This method supports the allocation of production capacity costs to those that use the system during peak, and that offpeak users need only pay energy costs. Industrials state that even where a utility needs to meet peak demand, it may construct a base load unit. The higher cost of a base load unit is justified by the need to serve peak users and the cost savings of cheaper fuel to serve existing customers.

Industrials contend the 2CP method most accurately reflects and accounts for additional capacity costs on UE's system. Industrials contend UE is a summer peaking utility and additional production capacity is only added to meet increased summer demand. Industrials reject other CP methods (4CP and 12CP) on the basis that once capacity is installed to meet summer peak demands, it can be utilized to meet all other monthly peaks without additional investment. The use of any other method, Industrials contend, causes unfair rate increases to Primary and Large General Service Class customers; that the use of any other method will prevent UE from attracting and keeping high load factor customers and will encourage demand during peak periods. The result of other methods would be to force the higher load factor Primary customers off the system.

Industrials' arguments can be summed up in their diagram reflecting how high load factor customers would be treated under a TOU system. (Exhibits B-39, B-40 and B-41). Industrials' primary emphasis is on the difference between its stand-alone system and a merged system using the same customers. Industrials' position assumes that those already in a system have some prior right to their existing allocation. Industrials contend the sharing of costs required by the TOU method penalizes high load factor customers whose use is mainly offpeak. The basis of this argument is that the system is already in place for peak users and offpeak users add no additional demand on the system.

5. Retailers

Retailers are proposing the adoption of the 4CP/average-and-excess (AE) method. This was one of the eleven cost of service studies produced by UE. Retailers contend that the 4CP/AE method represents a reasonable middle position on the issues involved in this case. Retailers agree that the appropriate method to select for allocation of costs to customer classes is one that most closely identifies cost with its cause. Retailers reject the CP methods, especially 2CP, because those methods ignore the fact that while total generating capacity of a utility may be determined by the definition of the peak used, the generating mix and the corresponding cost to the utility result from both peak and offpeak use.

Retailers recommend the Commission not adopt the TOU method because of the dramatic impact it would have on UE's rate structure. Retailers' 4CP/AE method is offered as a middle ground between the extremes of TOU and 2CP, and thus would arguably provide a method for moving to cost-based rates without a major change in Commission position on rate design. Retailers feel this case is not the appropriate vehicle for a major policy change concerning rate design.

6. Metropolitan St. Louis Sewer District

MSD basically took a position supporting the 2CP method presented by Industrials. MSD considers the rate structure issue in this case to be the most significant issue addressed. MSD asserts the 2CP method properly reflects cost causation of UE's system. MSD echoes the arguments addressed by Industrials concerning the proper method of allocating costs in UE's system.

7. Discussion

The decision of what cost of service study most closely reflects the class responsibility for the UE system most dramatically impacts on the distribution of production generation costs. In this case all studies were performed using the total revenue requirement requested by UE for the inclusion of the Callaway Plant in rate base. A decision concerning which method properly allocates these costs will determine how much each class will pay for the Callaway Plant.

Below is a chart showing the allocation of production costs using the parties' cost of service studies (Exhibit B-32, Schedule JP-R):

A COMPARISON OF ALL METHODS

	Staff	Union Electric (12 CP)	Union Electric (Avg.)	Union Electric (Avg. 4 CP)*	Industrials (2 CP)	Public Counsel
Residential	$ 509,177	$ 528,420	$ 560,830	$ 576,065	$ 589,253	$ 509,551
(Percent)	(41.33)	(42.89)	(45.52)	(46.76)	(47.83)	(41.36)
Small G.S.	177,808	180,556	170,865	166,035	173,159	177,247
(Percent)	(14.43)	(14.66)	(13.87)	(13.48)	(14.06)	(14.39)
Large G.S.	237,130	239,332	224,424	221,053	218,325	217,434
(Percent)	(19.25)	(19.43)	(18.22)	(17.94)	(17.72)	(17.65)
Primary	295,684	274,647	265,590	259,272	245,871	313,147
(Percent)	(24.00)	(22.29)	(21.56)	(21.04)	(19.96)	(25.42)
Lighting	12,192	9,036	10.282	9,566	5,381	14,612
(Percent)	(0.99)	(0.73)	(0.83)	(0.78)	(0.44)	(1.19)
TOTAL	$1,231,990	$1,231,990	$1,231,990	$1,231,990	$1,231,990	$1,231,990

* No column was prepared for Retailers' 4CP/AE method. This column is an average of all 4CP methods prepared by UE and Industrials.

The main objection of UE to the TOU/AP method is its effect on high load factor customers. UE contends, as do all CP supporters, that fixed generation costs vary with peak demand and once they are incurred they remain the same and do not vary with energy consumption. UE contends Staff's method shifts the costs of new production capacity from those who cause it, peak users, to those who help balance the system, high load factor customers. UE contends, further, that Staff's renaming of the classification from "fixed" to "capacity" and "variable" to "running" is merely semantics; what is really occurring, UE contends, is allocating demand costs as energy costs. It contends this shift of costs to energy penalizes offpeak users and high load factor customers.

Industrials make similar arguments against Staff's method and for the CP method. The Industrials are generally high load factor customers and they contend that they will be penalized under Staff's method. Industrials contend new investment in capacity is made to meet system peak demand and those using offpeak are making no additional demands on the system. Industrials contend the true relationship is between peak load and total investment, not average load and total investment.

Industrials attack Staff's method as not being based on real-world experience. They contend UE is a summer peaking system and the 2CP method properly allocates costs to those creating the need for more summer peak capacity. Industrials contend there is no evidence hourly average data accurately track costs. They contend the AP method double-counts high load factor customers and that Staff's cost of service study has serious technical flaws.

Finally, Industrials contend that Staff's cost of service study and the resulting allocation factors are not supported by competent and substantial evidence. They contend that only the 2CP method is based on competent evidence and that any party wishing to change an existing rate design has the burden of proof. Industrials cite Section 386.430, R.S.Mo. 1978, for the latter proposition. Section 386.430 relates to judicial appeals of Commission decisions and not to the burden of proof of a party in a rate case. All persons seeking adoption of specific rates within a rate case bear the same burden of proving that the proposed rates are just and reasonable. There is no additional burden in trying to change an existing rate structure.

Industrials' primary argument in support of its 2CP method rests on the contention that capacity generation costs are fixed and do not vary with kilowatt hour production. These fixed costs should be looked at in the short run with regard to their efficient utilization of existing facilities. Industrials contend that once new fixed generation capacity is in place, it should be allocated on the basis of who caused it to be built, i.e., peak users. They also contend that even in the long run the costs for new generating capacity are fixed and not variable as contended by Staff.

Industrials offered a statistical study of witness Chalfant to show an industry-wide correlation between production investment and a utility's peak demand. The results of the statistical study were brought into question by Public Counsel witness Finder. Finder performed certain revised studies which raised serious questions about the validity of Chalfant's conclusions.

Industrials cite the testimony of UE officials that new generation facilities are built to meet system peak. This testimony is contradicted by UE's Chief Executive Officer, William Cornelius, who stated that Callaway was built because UE needed new base load capacity in the 1980s. The testimony of UE officials merely demonstrates that Callaway was built for both peak and total demand. It does not amount to competent and substantial evidence to support the 2CP method.

The Industrials would have the Commission believe that somehow the peak responsibility method of allocating costs is more related to real-world experience than Staff's TOU method. Industrials do this by focusing on the fixed nature of generation capacity costs and the supposedly empirical data that peak demand causes additional generation capacity investment.

The Commission cannot accept this "real-world" argument of Industrials. First, the concept of generation capacity costs as fixed does not answer the important question of what causes the costs and how they should be allocated. Second, the 2CP method is just as theoretical as the TOU/AP method proposed by Staff. The argument that peak responsibility causes new generation capacity to be constructed is a theoretical argument.

The main concern of the Commission is to determine which theory most reasonably reflects the causation of production costs on the UE system. As stated earlier, the Commission has accepted in prior decisions, and again accepts, the TOU method as the most reasonable method for allocating the production costs of serving the various classes. The Commission thinks that Staff's position concerning causation is the most accurate and reasonable concerning the UE system. The Commission finds the evidence in this case supports the adoption of the TOU method. To adopt a CP method, one must first accept the contention that UE only builds new capacity to meet peak demand. The Commission cannot accept this. It is obvious

Callaway was built to meet both base load and peak demand, and its cost should be shared on that basis. The Callaway plant is the first plant in UE's loading order and UE will operate the Callaway plant as long as possible year-round.

Once one accepts the TOU theory and adopts the AP method as the closest approximation without the actual load data, the question of double counting as charged by Industrials becomes academic. The double counting alleged by Industrials only occurs if the peak responsibility theory is accepted. Under the TOU/AP method utilized by Staff and adopted by the Commission herein, there is no double-counting. Each class is allocated costs based on utilization of capacity at both peak and average loads. The double counting allegation comes from Industrials' position that specific demands cause additional capacity to be constructed. The Commission finds that the existing customers have no property rights in any particular rate or rate design and that it is the Commission's responsibility to determine what method most accurately tracks the cost of the UE system caused by the customer classes. Staff states the chronological occurrence of the load has nothing to do with the principal of cost causation as it relates to cost responsibility. The Commission agrees with this position.

Industrials contend the use of the 1989 load projections by Staff is a fatal error to the reliability of Staff's study. The Commission does not find the use of the 1989 load projections unreasonable. Staff has attempted to more accurately reflect the utilization of the various plants in the UE system and to ameliorate the impact of the Callaway Plant on UE's system. By using 1989 load projection the Staff has presented a more reasonable representation of the mix utilized by UE to produce power. The 1989 data is used as the average load over the next ten years. The Commission finds this is more reasonable than using only 1985 projections, where Callaway would completely dominate those projections. This is also reasonable based upon the Commission phase-in of the revenue requirement and rate design.

Industrials argue that true-up over five years is too long. The Commission considers that the impact of the Callaway Plant on the UE system is unique, and that it is reasonable to expect the impact of the Callaway Plant to be readjusted over a phase-in period. These adjustments may occur over a period of years, which is not unreasonable under these circumstances.

Industrials' argument concerning the unfairness of the allocation of average costs to primary service customers is a restatement of their position that existing customers have rights in the current structure. This is not true, as stated earlier. The Commission has found Staff's method to most closely associate costs with utilization and the results are not unfair on that basis.

Industrials attack Staff's use of the 12-month costing period as not "real-world". The Commission finds that the 12-month costing period is a reasonable approach to allocating costs to the utilization of the UE system during the entire year. Staff's method looks to what types and how much generation capacity would be purchased to meet demands in every hour of the year if it is assumed no production plant exists at the beginning of the year. The use of the monthly costing data by Staff to determine the use of the UE system over a year is reasonable and the Commission finds this method most accurately reflects how the UE system is used. The Commission again finds that the 2CP method is not the appropriate method for allocating those costs.

Although PC's cost of service study is based upon a similar theory as Staff's approach, the Commission believes Staff's approach is preferable in this case for several reasons. The Commission has previously adopted the Staff's approach in other rate design proceedings. Secondly, the Commission believes that the TOU/AP method is more precise than the method presented by PC and should be utilized until sufficient load data is available to complete a TOU study. Thirdly, PC also used 1985 load forecast data. The Commission finds that the use of load data farther into the future is preferable to ensure that the new base load addition (to the extent practicable) does not completely dominate the cost of service study. PC witness Finder also agreed that Staff's 1989 load data was more appropriate for use in a cost of service study in this case than the 1985 data used by PC.

Retailers presented what it considered a middle position between the extremes of Staff's TOU method and Industrials' 2CP method. Retailers made several recommendations concerning how the Commission should approach the rate design of the UE system. The recommendations involved in this part of the rate design issue are that the Commission should adopt customer class rates which recover all costs of providing service to the class, and that the 4CP/AE method is the middle ground which should be adopted for this case.

Retailers pointed out defects in the cost of service studies proposed by the other parties. Retailers attacked UE's across-the-board increase as unreasonable since it perpetuated the inequities that already exist in the UE rates. Retailers recommend the Commission adopt a reliable cost of service study to provide guidance to UE in balancing class costs and rates. Retailers support a method that brings the class rates of return within a 10-percent range of the system rate of return. Retailers support Staff's position that the UE system is built to meet total demand throughout the year, and investment in production capacity depends upon both the amount of capacity in megawatts and upon fuel type. The costs of production capacity should be apportioned between demand and energy. Retailers state that peak responsibility methods ignore the fact that generating mix and costs to the utility result from both peak and offpeak usage. Retailers support Staff's position concerning the utilization of production facilities and the cost causation of that utilization. Retailers, though, said Staff's AP method double-counts class average demands. In stating that Staff's AP method double-counts, Retailers is adopting the same position as did UE and the Industrials. That position is based upon a peak responsibility theory. If one accepts Staff's TOU/AP method, there is no double counting since Staff's method is based upon an allocation of costs for each hour of usage depending upon the class's utilization of the plant during that hour.

Retailers then argue that Staff's TOU/AP method has several serious flaws which make it unreliable. The flaws cited by Retailers are mostly those raised by UE witness Kovach in his rebuttal testimony. The criticisms concerning Staff's method and underlying data were answered by Staff witness Proctor in his rebuttal and surrebuttal testimony. Kovach's criticisms are based largely on misconceptions of the underlying theory behind Staff's method. Kovach's criticisms, and thus, Retailers', are based on the misconception that Staff's method allocates fixed generation costs by kilowatt hours and is thus subject to fluctuation and is inappropriate. The Commission finds these criticisms were addressed by Staff and do not undermine the adoption of the TOU/AP method.

Staff's TOU/AP method does not allocate fixed generation costs by kilowatt hour (kwh). Fixed generation (production) costs are allocated by utilization of capacity. Staff's method took UE load projection forecasts and developed a cost model, and then developed utilization of plants for 1989. This allocated capacity costs based upon plant utilization, not plant generation. Plant generation would be on a kwh basis. For most plants, this difference results in an allocation differential between kwh and Staff's capacity utilization method. In the case of the Callaway Plant, which has a 100-percent loading factor, the utilization and generation will be the same and thus, Callaway will be allocated on the same basis as energy or kwh. This does not render Staff's method inappropriate; it merely points up the effect that a large base load plant such as Callaway has on a system such as UE's, and also points up the reasonableness of using the 1989 load forecast. The discussion by Proctor in his rebuttal and surrebuttal testimony (Exhibits B-29 and B-30) and the supporting schedules succinctly illustrate the differences between Staff's method and allocation by kwh, and show that Staff's method does not allocate costs based upon kwh.

Staff uses replacement costs as a basis for allocating costs in its study, rather than historical costs. This case is the first time Staff has presented a study based upon replacement costs. Staff contends that this is a more appropriate method of determining the costs of a utility system because it more accurately reflects what the costs of that system would be if it were to be replaced or to be built to meet system needs. The Commission finds that it is reasonable to use capacity replacement costs instead of fixed costs and that those figures used by Staff are reasonable. Staff's method is based upon the concept that each class is responsible for its utilization of the system at any given hour. This means a utility system is viewed as starting from zero plant and that plant is built to meet need, with each class being responsible for its share of the costs of that capacity for each hour.

Retailers' final attack on Staff's method is the impact it will have on UE's customers. The Commission is concerned about the effect of the rate increase upon all ratepayers. Without any rate design change, Callaway will have a major impact on rates. Because of the impact of Callaway on UE's rates, the Commission will phase in whatever increase is granted. The Commission will phase in changes in the rate structure to minimize the impact of these changes upon customers within the major rate classifications. The impact argument, therefore, is not a sufficient reason to choose a less desirable method for rate design. The Commission can phase in any dramatic impact that is caused by any rate design adjustment because of the method which it adopts. The Commission, though, has found and believes that it is its responsibility to choose what it considers the most accurate method which matches costs with the causation of those costs. The Commission has determined Staff's method most properly allocates production costs to the classes. The Commission finds that further evidence of the reasonableness of Staff's method is the similarity in results it has with the 12CP method. The Commission views the 12CP method as the most appropriate coincidental peak method since it allocates costs throughout the year. The Commission finds that UE's 12CP results lend support to the reasonableness of Staff's TOU/AP method.

The Commission has indicated in recent cases that it believes the TOU cost of service study most closely reflects cost causation of a utility's production and transmission facilities. Staff presented the same method to the Commission in Case No. ER-81-364 involving Arkansas Power & Light Company (AP&L), issued April 20, 1982. In that case the Commission was presented with the same question of which theory properly reflected cost causation, TOU or CP. The Commission adopted the TOU/AP method. The Commission also adopted the TOU over the CP method of allocating the costs in Case No. EO-78-161, which involved Kansas City Power & Light Company.

The AP&L system was very similar to UE's. Most of AP&L's capacity costs were associated with base load units. Base load units generally operate year-round, with intermediate and peaking units added at various times to meet peak demand. The Commission found it was inappropriate to assign causation for the total cost of a system on the basis of class contribution to one hour of demand, as the 1CP method requires. The Commission then adopted the AP method because it most closely approximates the TOU hourly method. The Commission adopted the AP method because it allocated costs partially on the basis of class contribution to average demand and partially on class contribution to peak demand. The Commission felt this method would most closely allocate cost causation to the classes where the hourly load data necessary for a TOU allocation is not available.

The same arguments concerning the CP method versus the TOU/AP method appear in this case. The UE system is made up mostly of large base load units which are designed to run year-round. The Commission considers its reasoning from the AP&L case to be supported by the evidence in this case. The Commission reaffirms its position that costs are caused by the utilization of the system each hour, and the proper method of allocating those costs is on an hourly basis. Here, as in AP&L, there is no hourly load data, so Staff's study utilizing TOU monthly data and AP allocation within the month is found to most closely approximate the more preferable hourly TOU.

There were questions raised by several parties concerning the reliability of the data used by Staff to develop its allocations. Staff witness Pyatte testified she could not statistically verify the available data. This was because of the procedures followed by UE in collecting the data. Several parties characterized the data as unreliable and therefore argued Staff's entire study was unreliable.

Pyatte's testimony is not that the data is unreliable: she testified the data was unverifiable; that is, it could not be checked to determine its reliability. This data, though, was used by all parties in developing their cost of service studies. Pyatte testified this was the only data available and this data was better than no data in making judgments concerning the UE system. UE contends its data is not a problem.

The Commission has determined the data used in this case is sufficiently reliable for the purposes for which it was used. The Commission, though, believes that more accurate data should be kept by UE and made available to Staff so that a complete hourly TOU cost of service study can be performed. The Commission will order UE to collect the appropriate data.

B. Transmission Costs

Production and transmission costs are so closely linked that usually they are considered together when determining how those costs should be allocated. Because of the Callaway Plant, the Commission has separated production costs from transmission costs, as well as other costs, for purposes of determining the impact of Callaway on production costs. The Commission, though, does not consider it reasonable to adopt one method for production costs and a different one for transmission costs.

The Commission has determined that Staff's TOU/AP method is the appropriate method for allocating production costs, and the Commission also considers Staff's method the appropriate method for allocating transmission costs.

C. Distribution Costs

Distribution costs are separated into Plant Account Nos. 360, 361 and 362 (land, structures and substations), Nos. 364 and 365 (poles, towers, fixtures and overhead conductors), Nos. 366 and 367 (underground conduits and conductors), No. 368 (line transformers), No. 369 (overhead and underground services), No. 370 (meters), No. 371 (installation on customer's premises), and No. 373 (street lighting).

The Commission has reviewed the various proposals for allocating distribution costs. There is no real disagreement among the parties with regard to Account Nos. 370, 371 and 373. Those accounts will be allocated to customer classes based upon UE's method of allocation. The major differences between the various proposals concerning the other accounts involve the treatment of land, structures and substations (Account Nos. 360, 361 and 362) and the treatment of costs associated with the minimum system concept (Account Nos. 364, 365, 366, 367, 368 and 369).

UE allocated the costs associated with Account Nos. 360, 361 and 362 on the basis of class noncoincident demand (NCD) at the primary voltage level. UE's allocation was based on the allocation made in the NARUC "Electric Utility Cost Allocation Manual".

Staff contends that the land, structures and substation costs in Account Nos. 360, 361 and 362, except for "other distribution land", should be allocated on an average-and-peak (AP) basis. Staff argues that the AP method should be used because the distribution substations interface with the transmission system and so a method similar to the method used for allocating transmission facilities should be used.

The Commission finds that Staff has failed to provide sufficient evidence concerning the interface between the distribution system and the transmission system to justify the adoption of an AP method for allocating the costs associated with Account Nos. 360, 361 and 362. The Commission determines it more reasonable to allocate those accounts on the basis of class NCD as proposed by UE.

Both Staff and UE propose to allocate the remaining accounts by use of a minimum system concept. The Commission considers this to be a reasonable approach to allocating these costs. The costs associated with the minimum system are allocated on a per-customer basis. The minimum system concept, as viewed by UE, is that a certain minimum system must be built just to make service available to customers. UE contends this minimum system is not built to provide any demand or kwh. Staff defined the minimum system as if each customer were receiving service at the same minimum level of usage (kwh) and rate of usage (kw).

Staff and UE disagree regarding the allocation of the costs in excess of the minimum system. UE contends all of the excess should be allocated to customer classes based upon class NCD. Staff contends that a portion of the demand is related to the minimum system and this minimum demand should be removed before the allocation is made to the classes based upon class NCD.

There is little explanation or discussion of the minimum plant concept on a theoretical basis in the evidence. UE makes its assertions concerning the concept and Staff's makes different assertions. The Commission, in considering the minimum plant concept, cannot accept UE's position. It is only reasonable and logical that if a minimum system is established, it will meet a certain minimum demand. The Commission finds that Staff's method of determining the minimum demand system and Staff's allocation of the costs in excess of the minimum system is the most reasonable approach presented by the parties and is just and reasonable based upon the evidence.

PC offered a proposal for allocating the costs associated with Account Nos. 364 through 367. These accounts are allocated by use of minimum systems by UE and Staff. PC's method allocated the costs associated with these accounts on an AP basis. PC used an AP method as a proxy for a method that gives recognition to the existence of economies of scale in the distribution system. The Commission is not convinced by PC's evidence that its method is the preferred method for allocating distribution costs. The Commission has rejected the AP method of Staff for Account Nos. 360, 361 and 362 and does not believe it is reasonable to adopt an AP method for those other accounts proposed by PC.

Industrials contend that investment in distribution equipment is totally dependent on demand and not related to kwh usage. Industrials contend that since a large portion of Primary Class is served by UE-owned substations on the customers' property, there should be a reduction in the allocation for those customers. UE and Staff assert that even though Industrials may be right, there are some distribution costs associated with primary service usage and UE does not separate those customers receiving service in this manner in its accounts. The Commission finds it would be unfair to reduce the allocation as proposed by Industrials for the reasons stated by UE and Staff.

D. Customer Expenses

Customer-related expenses include meter reading, billing and records, uncollectable accounts, customer assistance and customer advances. UE and Staff presented different methods of allocating the costs associated with these services. Industrials and PC generally adopt UE's allocation.

The Staff and UE have only two major areas of dispute, meter reading and billing and records. There is general agreement on the allocation of the other costs and the Commission will adopt the allocation methods proposed by UE for those costs.

1. Union Electric

In allocating Account No. 903, billing and records, UE allocated 20 percent of the expenses associated with this account to Account No. 904, uncollectable accounts. The remaining 80 percent UE allocated to each customer class based upon its weighted meter allocation factor. UE allocated meter reading expenses by the same weighted factors. Those factors are:

Residential		1.0
Small General Service		1.9
Large General Service		10.7
Primary		86.1
Lighting	(composite)	43.2

UE contends its weighting factors take into account the differences in meter reading and billing and records for the various types of meters. The factors account for the differences in complexity between the various classes in these two areas.

2. Staff

Staff developed a separate allocation factor for meter reading and one for billing and records. Staff allocated meter reading costs to customer classes based upon a weighted number of meters. The weighting factors were developed from a UE meter cost study and from meter reading difficulty weights taken from a study done by Arkansas Power & Light Company in Case No. ER-83-206. The two studies were combined to develop "rough class weighting factors". The weighting factors were then applied to the number of customers in each class, and for lighting, to the number of meters.

Staff's position is that these weights only partially substitute for a meter reading study. No such study is available for UE. Staff contends its weights better reflect relative costs for meter reading than weights based on meter costs.

For billing and records Staff allocated costs based upon the average number of customers. Staff contends without a suitable study to develop accurate data, the best course is to allocate these costs to all customers equally.

3. Discussion

The Commission has considered the two positions concerning allocation of meter reading and billing and records costs. The Commission understands Staff's concern regarding the proper allocation of costs. In regard to these two cost accounts, the Commission cannot accept Staff's proposed method of allocation for meter reading costs. The Commission is not convinced that the "rough" weighting factors developed by Staff are sufficiently related to UE's system to utilize. The Commission considers the weighting factors used by UE to be a more reasonable method of allocation for these costs. The weighting factors based upon cost of meters give consideration to the increased complexity for meter reading associated with more complex meters. The Commission does not consider either of the two methods the best possible method, but has chosen what it considers to be the more reasonable approach, based upon the two methods presented.

UE would have the Commission adopt a method for allocating costs of billing and records based upon costs of meters. There seems to be little direct correlation between costs of meters and billing and records. Staff would have the Commission allocate the costs to all customers equally. This is based upon a concept that all should share equally when no proper data exists.

The Commission must decide which is the more reasonable method based upon its own judgment of how the costs should be allocated. The Commission has reviewed the factors used by UE, set out earlier, and cannot without further justification adopt a system which allocates billing and records costs on an 86:1 ratio between primary and residential customers. Of the two methods, the Commission considers that treating all customers alike is a more reasonable approach.

Staff has indicated a study should be made to determine the proper allocation of costs for meter reading and billing and records. The Commission does not consider such a study advisable unless Staff can show the benefits outweigh the costs. On that basis no study will be ordered in this case.

E. Taxes

Laclede Gas Company (Laclede) and Industrials have proposed different methods for allocating income taxes to each class. Industrials propose to allocate income taxes to each class on the basis of net taxable income. Laclede proposes to allocate income taxes to each class and then to seasonal subgroups within the

Residential Class on the basis of net taxable income. Neither party addressed this allocation of income taxes in its briefs.

UE, Staff, PC and Retailers allocate income taxes on the basis of net original cost rate base. UE contends that a large portion of income tax deductions is related to investment in plant and that ignoring rate base investment, as did Laclede and Industrials, is wrong. UE contends further that Laclede's and Industrials' methods overallocate income taxes to above-average rate of return classes and underallocate income taxes to below-average rate of return classes.

The Commission, having considered the methods proposed for allocating income taxes, agrees with the method proposed by UE. The Commission finds that UE's method is the most reasonable method to allocate the income taxes to the various classes.

F. Administrative and General

PC, Staff and UE took different positions with regard to allocation of administrative and general (A&G) expenses. UE's position is that except for the expense associated with the Electric Power Research Institute (EPRI), the A&G expenses should be allocated on the basis of direct labor. EPRI expenses were allocated based upon a formula incorporating UE's kwh sales and revenues during a previous year.

Staff's position is that all A&G expenses should be allocated on the basis of total cost of service less A&G expenses. PC allocated A&G expenses as follows: pensions and benefits - labor; EPRI - rate base; properties insurance - rate base; and payroll taxes - labor. These categories are indicated in the hearing memorandum as expense items for which specific allocation factors were developed by PC. PC witness Finder in his testimony (Exhibit No. 48, Schedule AEF-9) does not list payroll taxes but does list Account No. 928, which is regulatory commission expenses, which he proposes to bill by kwh. PC allocated all remaining A&G expenses in proportion to each class's share of total allocated costs.

The Commission has reviewed the positions of the parties on this issue. The Commission has determined that UE's position is the proper method for allocating A&G expenses, including EPRI expenses. The underlying rationale of UE's position is that it is through its employees that the coordination and management of all facets of its operations are conducted, and that therefore the proper method to allocate costs associated with those employees' expenses is by direct labor. The Commission considers this method to be the most reasonable of those proposed.

G. Rate Structure

The Commission has determined the proper allocation of costs associated with providing electric service to the various classes as set out above. The next step in assigning rates is to determine the rates that will be paid by the individual customer in each class. In establishing the rate structure within each class to produce the required revenue, the costs allocated to each class are assigned as they relate to customer-related costs, demand-related costs and energy-related costs. These costs are assigned to a monthly customer charge, an energy charge per kwh, and a demand charge per kw. The Residential and Small General Service Classes on UE's system will have rates that include only a monthly customer charge and a kwh energy charge, since they are not demand-metered. The rates set out in the graphs in the following sections are based upon UE's total request. The rates are for comparison purposes only. To arrive at the rate structure for each class, the Commission submitted hypotheticals to the parties. These hypotheticals and the reply data enabled the Commission to see the impact of proposed adjustments to the rate structure on individual customers. The hypotheticals and responses have been made a part of the record in this case.

H. Residential Rate Structure

UE, Staff, PC and Laclede addressed the issues of intraclass rate structure for the Residential Classes.

1. Union Electric

UE proposes a rate structure including a $7.50 monthly customer charge, 11.10 cents per kwh for all kwh consumed during the summer period and, for the winter period, a charge of 7.30 cents for the first 600 kwh, 6.50 cents for the next 400 kwh, and 5.00 cents for all additional kwh. UE states the customer charge should be $10 per month, but it proposes limiting the increase to the cost of establishing, maintaining and servicing the customer's account and the monthly costs associated with the customer's meter service, wire or cable, and a minimum level for transformer capacity. Those costs not included in the customer charge are included in the energy charge for summer kwh and in the initial winter block kwh charge. UE states it is proposing a flat summer rate since a flat rate was agreed to in its last rate case.

UE performed a seasonal cost of service study to develop the demand portion of the Residential rate. UE divided residential customers into subgroups based upon kwh usage, with the summer period a separate subgroup. UE used the 12CP/AE method to determine the production and transmission portion of costs which should be allocated to the summer period and those which should be allocated to the winter period. UE performed similar seasonal analyses to determine the individual customer noncoincident demand (NCD) for allocation of distribution costs. These were determined for the summer and winter periods using the AE allocation method. Energy-related costs were allocated on the basis of kwh sales of each subgroup. Remaining costs were allocated in a similar manner.

UE then developed a revenue target for each subgroup, using an equal rate of return within each subgroup. This overall Residential Class rate of return was 9.29 percent based upon the total increase in rates being requested by UE. The total of all costs plus rate of return was compared to existing rates to determine the amount of increase required within each subgroup, taking into account the increased monthly charge.

UE then developed its rate structure based upon the results of this process. UE states its method shows summer period costs should increase approximately 82 percent and there should be a winter block at the 600 to 1,000 kwh level. Usage over 1,000 kwh for the winter period was proposed to be increased by 60 percent.

UE justifies its residential rate structure on the basis its study indicated that customers with higher winter consumption have increased load factors. UE asserts load factor is an indication of efficient utilization of the fixed facilities of its system for which an individual customer, subgroup or customer class is responsible. UE asserts the rates necessary to recover fixed costs not containing a demand charge will go down as load factor improves. This accounts for the declining block rate in the winter period. UE's rate structure was developed to take into account seasonal differential to encourage improved load factor for customers.

2. Staff

Staff proposed a residential rate structure which based rates on billing units directly associated with the customer load information used in Staff's cost of service study. Staff proposes a monthly customer charge of $5 and seasonal energy charges for summer and winter periods. The summer rate has an initial block of 0 to 600 kwh, with a charge of 10.929 cents per kwh and a declining block above 600 at a charge of 9.208 cents per kwh. The winter rate has three blocks. The initial block is from 0 to 600 kwh, with a charge of 8.256 cents per kwh; a middle, declining block from 600 to 1,000 kwh at a charge of 6.535 cents per kwh; and an inverted tail block of 1,000 kwh and above, with a charge of 7.123 cents per kwh.

Staff states that three components go into the base rates of all classes. These are: (1) minimum system distribution costs, (2) additional distribution demand costs over minimum system to cover all base usage, and (3) general overhead and other nonrelated costs. The costs associated with the base rate for the Residential Class are to be collected through the initial winter block charge. The tail block of over

1,000 kwh for the winter period is to collect the additional demand Staff contends is caused by space heating customers.

Staff determined a minimum system demand, a base demand and a summer demand to design its rates. The base demand is equal to the minimum system demand for most residential customers. For the other residential customers, base demand is the customer maximum demand in October or May, whichever is lower. Then the difference between the base demand and minimum system demand and the base demand and summer maximum demand are calculated. The percentages arrived at are used to allocate distribution demand costs between base rate and summer rate. These calculations measure the additional demand caused by additional demand in the summer.

3. Public Counsel

PC proposes a monthly customer charge of $5.75. This charge includes the cost of service and a meter, customer accounts expense, and customer service and informational expense. PC proposes a summer flat rate of 9.27 cents. PC stated that it proposed a winter differential of 1.2 cents per kwh between the winter and summer rates, and a winter tail block of 6.33 cents per kwh. A chart prepared by Laclede's witness in Exhibit B-74 shows PC's composite winter rate at 8.07 cents.

PC's differential between summer and winter rates is to recover the seasonal differential in energy costs, the Residential Class share of generation demand costs, and the demand costs associated with power purchased in the summer months. The winter tail block rate is designed to recover average generation and transmission costs per kwh during the winter period, adjusted for administrative and general costs. The proposed winter tail block rate does not include a contribution for distribution and customer costs.

4. Laclede Gas Company

Laclede utilized UE's total revenue requirement for developing its proposal for residential rates. Based upon its adjustment of UE's residential class cost of service study, Laclede proposes a monthly customer charge of $7.50, a summer flat rate of 9.34 cents per kwh, and a winter initial block charge of 7.86 cents for usage from 0 to 1,000 kwh and a declining block charge of 7.17 cents for usage above 1,000 kwh.

Laclede adopted UE's monthly customer charge. Laclede states its summer charge is the rate needed to recover summer energy costs plus the portion of the summer customer costs not recovered by the customer charge. Laclede asserts there is no justification for a substantial decline in the tail block in the winter period. The initial winter block is developed to collect the portion of the winter customer costs not recovered by the customer charge. Laclede adjusted UE's intraclass cost of service study to arrive at its residential rate structure. Laclede asserts its results indicate there is no justification for a substantial decline in winter rates for usage over 1,000 kwh.

5. Discussion

Below are set out the various proposals for residential rate structure. These rates are not comparable for all parties since some parties used different total class revenue requirements. The best way to compare the result or impact of each proposal is by comparing the percentage seasonal differential within each proposal and the current percentage seasonal differentials. There are several ways to compute differentials. The parties have used a differential which shows the percentage increase the summer rate is over the winter rate. The Commission will use this differential.

Below are the current and proposed rates for the Residential Class:

	Current	UE	Staff	PC	Laclede
Customer Charge Monthly	$4.30	$7.50	$5.00	$5.75	$7.50
Summer Energy Charge (kwh):					
0 - 600	6.10¢	11.10¢	10.929¢	9.27¢	9.34¢
601 - 1,000	6.10¢	11.10¢	9.208¢	9.27¢	9.34¢
1,001 +	6.10¢	11.10¢	9.208¢	9.27¢	9.34¢
Winter Energy Charge (kwh):					
0 - 600	4.75¢	7.30¢	8.256¢	8.07¢*	7.86¢
601 - 1,000	4.75¢	6.50¢	6.535¢	8.07¢*	7.86¢
1,001 +	3.10¢	5.00¢	7.123¢	6.33¢	7.17¢

*composite

The percentage seasonal differentials as compared to the current percentage seasonal differentials are shown below.

% Rate Differential Summer/Winter By Block	Current	UE	Staff	PC	Laclede
0 - 600	28%	52%	33%	15%	19%
601 - 1,000	28%	71%	41%	15%	19%
1,001 +	97%	122%	29%	47%	23%

The differentials between winter and summer rates for the parties are based upon the parties' application of their own cost of service studies to the rate structure. To allocate costs to the various classes, UE proposed an average increase across the board. UE, though, within the Residential Class, has used a 12CP/AE cost of service study to allocate production and transmission costs. UE's method allocates those costs 55 percent to the summer period and 45 percent to the winter period. There are four months in the summer period and eight months in the winter period. Staff's TOU method allocates 45 percent to the summer period and 55 percent to the winter period. Staff contends that the 12CP/AE method is acceptable if there is no TOU method available, but since Staff proposed a TOU method in this case Staff contends that the 12CP/AE method is not the most appropriate method in this case. There is a 10 percent difference in cost allocation for the Residential Class between Staff's and UE's methods. Staff states that this difference is caused by its allocation of the higher-cost base load plants over the entire year, and therefore to the winter period, under its capacity utilization concept. The difference occurs also because UE uses Class load factors in its computations instead of system load factors.

Another reason for the substantial difference between the rates proposed by UE and those of Staff is due to the allocation of distribution costs. UE allocated distribution costs based upon the AE method and subclass noncoincident peak. Staff points out UE's allocation method is unclear but the results are to allocate a substantial portion of distribution costs to the summer period; thus, UE must be using summer peak demand to allocate distribution costs.

Staff argues that NCD is proper for allocating distribution demand costs to the Classes, but that within the Classes certain subgroups peak in the winter period and the allocation of distribution costs should take this into account. Staff's method allocates a portion of distribution costs to the winter period. Staff contends that UE is assuming that its distribution system is sized to meet customer NCD for the summer period and that high load winter period customers place no additional demands on the distribution system. Staff asserts there is no evidence this is true. Staff also asserts all-electric subdivisions are where this is not true. Staff contends that, under UE's rates, the high summer usage customers will subsidize higher winter usage customers.

Staff contends that without considering distribution costs, UE's proposed winter rates do not recover the minimum energy cost and demand cost associated with winter usage. Staff asserts UE improperly applied the 12CP/AE method. Staff states it has serious reservations about UE's intraclass cost of service study because of its improper application. Staff asserts that customers who have air conditioning and gas heat will subsidize those customers with no air conditioning and electric heat under UE's rates.

UE has contended that Staff has failed to take into account the increased efficient use of the system and benefits from high load factor customers, and the impact on the customers of its TOU method and proposed rates. Staff states that it has considered the impact of its proposed rates, but those impacts should be viewed in terms of annual bills rather than just winter bills as proposed by UE. Staff asserts that higher winter bills will be offset by lower summer bills for those customers who are affected by Staff's rate structure. Staff also asserts that it does not have the individual billing data for the Residential Class to determine the exact impact of its proposed rates. Staff also asserts that the information is not available to determine whether load factor will be improved by the adoption of UE rates or will be disadvantaged by the adoption of Staff's rates. Staff does state that seasonal load factor is a concern for the residential customer and is a short-run goal in structuring rates for the residential customer. However, Staff states that UE does not address the problems or provide support for its contention that its rate structure will improve seasonal load factors for its customers. Staff asserts that the seasonal differentials of UE's current rates are not cost-justified and that it cannot, in good conscience, propose that the current intraclass subsidies continue or increase by accepting UE's proposed structure, and that the current subsidies should not be continued just to improve seasonal load factor. Staff asserts this is especially true noting the substantial increase in rates proposed in this case and the high probability that even UE's rates will not provide a substantial improvement in load factor because of those increases.

Laclede points out the same problems as does Staff with UE's cost of service study. Laclede also makes an analysis of that study and makes adjustments it considers proper, and comes up with what it considers to be the proper rate structure based upon the 12CP/AE method. Laclede points out that UE develops a

55/45 allocation of costs to summer/winter periods. Laclede then points out the problems with UE's cost of service study, especially the problem of only using four winter months to determine the peak demand, rather than the eight months which are actually in the winter period. Laclede asserts, therefore, that UE's study does not accurately reflect the results of the 12CP/AE method. Laclede states that the results it obtains from the adjustments of the corrections made to UE's 12CP/AE method are an allocation of production and transmission costs on approximately a 50/50 basis to summer/winter periods. Laclede also asserts that UE misapplied its study when it developed its rates. Laclede states that UE's subgroups which were used to develop the percentages were then transposed directly to the rate blocks. Laclede asserts that there is no direct relationship between the subgroups and the rate blocks. Laclede also asserts that UE's rates will undercollect for the winter period and overcollect for the summer period. Laclede supports Staff's position that one should look at the annual bill to determine the impact of the proposed rates, rather than just the winter bills. Laclede states there is no price elasticity study to support UE's load factor arguments and there is no real justification for declining rates in the winter blocks. Laclede states that using the 12CP/AE method with its adjustments, as can be seen by the charts above, results in proposed rates closer to those of Staff than to those of UE.

The Commission has reviewed the various proposals for the intraclass rate structure for the Residential Class. The Commission has already adopted Staff's method for allocating production and transmission costs among the classes. The Commission has determined that Staff's proposal for changing the rate structure provides the basis for structuring UE Residential Class rates. The Commission, though, cannot accept all of Staff's proposals. The Commission will adopt those portions which it finds reflects the proper structure in the Residential Class.

Staff has proposed a declining block in summer rates and an inverted tail block in winter based upon a strict application of its allocation of production, transmission and distribution costs. The Commission believes Staff is correct in assigning more costs for the production and transmission costs to the winter periods. Winter customers should bear their proper share of the costs of the UE system.

The Commission, though, must weigh other considerations in the relationship between rates paid by customers. The Commission cannot accept Staff's proposal of a declining block in summer. The Commission can find no justification for the declining summer block other than Staff's application of its allocation method. Even though the rate increase from this case will be substantial, there should be no signal to summer users that using more power costs less.

The Commission does not believe Staff's middle declining block and inverted tail block in the winter rate are justified. The Commission does not believe Staff has sufficiently supported its assertions about the distribution system to create an inverted tail block in the winter. The Commission believes that a declining block at the 1,000 kwh usage level is the structure supported by the evidence and which best reflects the usage of UE's system.

The Commission considers UE's proposal for the customer charge to be too high. Even though a lower monthly charge may not recover all costs associated with customer expenses, the Commission does not believe the low usage customer should bear such a large portion of the rate increase in the form of the customer charge. The Commission has therefore adopted PC's proposal of a customer charge of $5.75 per month. The customer charge will not be phased in.

The Commission has adopted Staff's basic concept for cost causation and so believes the rates should move in that direction. Since the entire rate increase in this case will be phased in, the Commission has determined the move to the final rates adopted for the Residential Class should be also phased in. The phase-in should be in increments for each year of the phase-in until the rates reach the proposed level at the end of the phase-in period.

The Commission has used the initial winter block as the starting point for setting rates. The initial winter block rate will increase to 8.00 cents/kwh at the end of the phase-in period. The phase-in is illustrated in the chart in the Summary Of Rate Design.

The summer and winter tail block rates will be determined based upon the initial winter block rate. The Commission has determined the differential between the summer and winter tail block should be 75 percent at the end of the phase-in period. The current differential is 97 percent. UE proposed a 122 percent differential and Staff a 29 percent differential. The Commission has already rejected UE's proposal and although it is adopting Staff's allocation of costs, it believes Staff's movement is too extreme. Also, Staff's differential is based upon an inverted winter tail block which has been rejected.

The summer/winter tail block differential will move in equal increments from the current 97 percent to the final 75 percent each year of the eight-year phase-in period. Each year rates for summer and winter tail block will be adjusted accordingly.

The Commission has set out a chart in the Summary Of Rate Design section which shows the yearly change in rates.

I. Small General Service Rate Structure

As with residential rates, Small General Service (SGS) rates include only a monthly customer charge and energy charge, since SGS customers are not demand-metered. UE and Staff are the only two parties that proposed a specific rate structure for the SGS Class. Cities and State addressed the issue of the size of any rate structure increase for SGS Class in conjunction with the specific issues each presented.

The parties agree that the SGS Class should receive a smaller overall increase than other customer classes based upon the cost of service studies, which show the rate of return for the SGS Class has been substantially higher than the rate of return for other classes.

The current rates and the proposals of UE and Staff are set out below.

	Current	UE	Staff
Customer Charge Monthly			
Energy Charge	$7.15	$12.00	$7.15
Summer:			
Base	6.96¢	12.00¢	9.185¢
Seasonal (Excess)			7.825¢
Winter:			
Base	5.68¢	9.00¢	8.094¢
Seasonal (Excess)	2.88¢	6.30¢	6.734¢

UE has proposed to continue the current rate structure and increase the rates. Staff has proposed to establish a base and seasonal charge for the summer period rather than the current flat rate. UE's and Staff's rates are based upon their own views of how the costs within the SGS Class should be allocated. Both have agreed to a designation of the charge over the base charge as a "seasonal" charge rather than an "excess" charge. Both UE and Staff define seasonal usage as "all kwh in excess of 1,000 kwh per month and in excess of the lesser of a) the kwh use during the preceding May billing period, or b) October billing period, or c) the maximum monthly kwh use during any preceding summer month."

UE objects to Staff's method of allocation, as it does in all instances, because of Staff's allocation of production and transmission costs to the winter period. UE again asserts Staff's allocation method imposes a more severe impact on high load factor customers and does not account for the benefits to the system of the high load factor customers.

In its base rate Staff proposes to recover certain costs which are incurred regardless of a customer's load. The costs to be recovered are minimum system distribution costs, additional distribution demand-related costs over minimum system to cover all base usage, and general overhead and other nonrelated costs. Staff justifies its summer seasonal charge because it does not include the costs associated with the base rate.

The chart below sets out the difference between the current rate differentials and UE's and Staff's proposals. UE is proposing to increase the differential between the summer and winter rate, while Staff proposes to decrease the differential. Staff recommends a maximum differential of 25 percent if a flat rate is retained for the summer period. Staff proposes a range of 20 percent to 40 percent differential between the summer rate and the winter seasonal rate, if the summer flat rate is retained.

% Rate Differential Summer/Winter	Current	UE	Staff
Base	23%	33%	14%
Seasonal	142%	86%	16%

The Commission has reviewed the two positions concerning SGS rate structure. As with Residential, the Commission does not believe a substantial increase in the customer charge is justified. The Commission agrees the SGS Class has been earning a rate of return substantially above the system average rate of return. Therefore, SGS should receive a lesser percentage increase overall than the other classes. The Commission adopts UE's proposed "seasonal" designation for usage above base and adopts UE's definition of seasonal usage.

The Commission has determined the monthly customer charge should remain the same for the SGS Class. The current rate is $7.15. The Commission does not believe a declining block in the summer rate is supported by the evidence or is justified based upon the proper signal concerning usage to be sent to the customers.

The Commission, as with the other classes, has determined that Staff's method of allocating production and transmission costs is the appropriate method. This increases winter rates more than summer for SGS customers in this case. The Commission has determined this move should be made over the eight-year phase-in period. The Commission has adopted a flat summer rate and a two-step declining block rate for the winter period for the SGS Class. For a customer to be eligible for the winter seasonal rate, a customer must have a minimum base usage level of 1,000 kwh.

The Commission has used the winter base demand as the known rate for determining the summer flat rate and winter seasonal rate. The winter flat rate will be 8.00 cents at the end of the phase-in. To reach the 8.00 cents the winter rate will increase in increments each year of the eight-year phase-in. The Commission has determined the differential between the summer flat rate and the winter seasonal rate should be 42 percent at the end of the phase-in period. The current differential is 142 percent. To reach the 42 percent differential, the differential should be reduced by equal increments each year of the eight-year phase-in period.

The Commission has set out a chart in the Summary Of Rate Design section which shows the yearly change in rates.

J. Large General Service Rate Structure

UE, Staff and Retailers have addressed the Large General Service (LGS) rate structure.

1. Union Electric

UE proposes to alter the structure of current LGS rates. UE proposes a customer charge of $50.00 per month and a kwh charge of 2.85 cents for all months. UE proposes a demand charge of $20.00 per kw for the summer period, and a $14.60 per kw demand charge for base kw and a $9.00 per kw demand charge for seasonal kw for the winter period. UE arrived at these rates by segregating the cost components of the LGS Class and dividing by the number of customers and kwh billing. UE then assigned approximately 15 percent of fixed production costs to the kwh charge. This 15 percent, UE states, is generally related to higher demand caused by higher load factor customers.

UE developed its seasonal demand charges through an analysis similar to that used for its proposed Residential and SGS rates. UE's analysis indicated that

45 percent of production costs should be allocated to the summer period and 55 percent to the winter period. UE redesignated its rate above the base rate as a "seasonal" rate rather than "excess". UE also redefined base demand as follows:

> "The base demand shall be the lesser of a) a customer's demand established during the preceding May billing period, or b) October billing period, or c) the maximum demand established during any preceding summer month, but in no event less than 100 kw."

This change, UE contends, will result in a more equitable recovery from high load factor LGS customers.

UE proposes to change its rate limiter for LGS customers. A rate limiter sets a maximum charge per kwh which a customer must pay regardless of what the bill would be if calculated with the other provisions of the rate. UE contends that rate limiters are unjustifiable economically and create subsidies between customers within a class. UE states that rate limiters favor the poor load factor customer.

The current rate limiter is based upon 150 kwh per kw, which is a 21 percent load factor, and applies to both energy and demand charges. The rate limiter guarantees a customer a rate based upon at least a 21 percent load factor even if the customer's load factor is less than 21 percent. UE proposes in this case to retain the limiter for the demand charge. Based upon a usage level of 100 kwh per kw, or a 14 percent load factor, UE proposes the rate limiter to require payment of demand charges based upon the lesser of (a) the actual billing demand at the applicable demand charge or (b) the applicable cents-per-kwh rate limitation. UE is also proposing the minimum billing demand of 100 kw at the applicable seasonal demand rate will always be the monthly minimum demand charge under (a) and (b).

UE proposes, additionally, to remove the option for a customer receiving service on Primary voltage to be billed on the LGS rate. LGS is a secondary voltage rate. UE asserts this is a move to simplify the administration of its rates by charging a customer by the customer's rate classification.

2. Staff

Staff proposes an LGS rate structure with a monthly customer charge of $65.00, an energy charge of 4.731 cents/kwh, a demand charge for summer of 12.536 cents/kwh for base demand and 9.076 cents/kw for seasonal demand, a demand charge in winter of 11.228 cents/kw for base demand and 7.82 cents/kw for seasonal demand, and a rate limiter for all kwh of 12.72 cents/kwh for summer and 11.945 cents/kwh for winter. Staff states the current customer charge is based upon the assumption that billing costs are the same for all customers. Staff states its cost of service study shows all allocated customers' costs to be $50.00 a month, but Staff is only proposing a $65.00 charge in this case because it wishes to obtain more detailed billing and meter-reading data before moving to the $50.00 charge. Staff proposes to retain the current rate limiter.

Staff developed its energy costs by its TOU allocation of production and transmission costs as well as average-related distribution substation costs. Staff developed its demand costs by use of its TOU allocation of production and transmission costs and included summer-related distribution costs. Staff suggests that other rate component levels could be consistent with its cost of service study, but that for LGS, if the rates include all Callaway-related costs, the rates should not be lower than those proposed by Staff. The rate can be lowered on a percentage basis excluding customer charge if Callaway is phased into rates.

Staff states its seasonal rate differentials are the result of the allocation of distribution demand costs. The seasonal allocation of production costs, under its method, does not result in a very large seasonal differentiation in rates. The rates proposed by Staff are the lower boundary on seasonal differentials. Larger seasonal differentials can be obtained by allocating less distribution demand costs to the base component and more to the summer component. Staff suggests taking impacts of rates into account in establishing summer and winter differentials.

3. Missouri Retailers Association

Retailers propose that any increase to LGS customers be spread equally to demand and energy components of LGS rates. Retailers contend there is no justification for increasing the demand charge component of the LGS rate substantially. Retailers state to the extent demand charges are designed to reflect marginal cost signals, they should probably be reduced rather than increased. Retailers assert that for the LGS Class, every charge should reflect the possibility that UE will sell low-cost nuclear power over the interconnect grid. Retailers state that their proposals closely reflect their 4CP/AE allocation method.

Retailers presented a rate structure for the first year of a phase-in period. Retailers proposed a monthly customer charge of $50.00; a demand charge, all kw, of 12.21 cents; an energy charge, all kwh, of 2.882 cents; and a rate limiter of 12.21 cents for the summer; and in the winter period a base demand charge of 7.84 cents/kw; a seasonal demand charge of 5.21 cents/kw; an energy charge, all kw, of 2.882 cents; and a rate limiter of 7.84 cents. Retailers state their proposal reflects their cost of service study method and their proposal would have a more uniform percentage increase to LGS customers than does UE's proposed rates.

4. Discussion

UE attacks Staff's rate structure on the basis it has opposed Staff's allocation method. UE contends Staff's proposals place excessive amounts of fixed production and transmission costs in the energy kwh charge and on the winter period. UE again asserts the longer winter period does not mean that period causes increased demands on the system. Since winter kwh exceeds summer by 70 percent and winter billing demands exceed summer by 79 percent, UE states that Staff allocates substantially more fixed production and transmission costs than is proper to the energy charge.

UE opposes Staff's energy charge, claiming it exceeds Staff's average running costs. UE contends its allocation of 15 percent of demand costs to the energy component is more appropriate. UE again contends that Staff's allocation of costs will impact heavily on high load factor customers. This impact is felt heavily, also, by winter customers since high winter usage means improved load factor for UE customers. UE also objects to Staff's rate limiter proposal.

Below are set out charts which show the rates proposed for LGS rates and the seasonal differentials of the proposals as compared with current rates.

Chart A

	Current	UE	Staff	Retailers*
Customer Charge	$85.00	$50.00	$65.00	$50.00
Energy, All kwh	2.35¢	2.85¢	4.731¢	2.882¢
Demand Charge (per kw):				
Summer - Base	$10.48	$20.00	$12.536	$12.21
- Seasonal			$9.076	
Winter - Base	$6.03	$14.60	$11.228	$7.84
- Seasonal	$4.01	$9.00	$7.828	$5.21

*This is only a first-year phase-in increase.

Chart B

% Differential Summer/Winter	Current	UE	Staff
Demand - Base	73.8%	37%	12%
- Seasonal	161%	122%	16%

Staff asserts the differences between its proposals and UE's are reflections of the differences in their respective methods of allocating production and transmission costs to demand and energy charges. UE allocates 15 percent of fixed production and transmission charges to energy and Staff allocates 50 percent. This difference results in the extreme differences in the summer and winter differentials of the proposals. Staff asserts that significant reductions in the seasonal differentials are required to reduce the misallocation of costs within the LGS Class. Staff states it will support a maximum 25 percent seasonal differentiation.

Staff supports the base seasonal charges for the LGS Class on the same basis as its SGS proposal. Staff contends the base demand charge recovers nonweather-sensitive costs, which do not vary with changes in customer loads. Staff opposes UE's restriction of the rate limiter without a study showing the effect that restriction would have on LGS customers. Both Staff and UE agree to a lower customer service charge, as does Retailers. Staff would only go part-way until more data is available.

The Commission has already found that for the inclusion of the Callaway Plant into rates Staff's method is the most appropriate. Callaway is a base load plant and will be used all year round as the first source of power on UE's system. The Commission has found this means customers who use UE's system should share the cost of Callaway based upon their year-round usage, not just peak usage.

The Commission finds that Staff's method of allocating production and transmission costs is appropriate for intraclass allocation of costs and the appropriate basis for designing a rate structure. The Commission, though, must weigh impact on customers and other concerns in designing rates. The Commission therefore does not believe a full move to Staff's proposal is appropriate. Even Staff did not contend a strict application of its method should be adopted, but presented what it felt were the acceptable parameters.

Based upon its findings concerning the appropriate allocation of costs intraclass and its concern with the impact on customers, the Commission will phase in the rates it has found to be most reasonable. The Commission has found that a movement toward Staff's rates is necessary, but has determined that a full move is not justified based upon the evidence concerning the impact on higher load factor customers.

The Commission has adopted Staff's monthly customer charge because it agrees with Staff that a full movement is not justified at this time without further data. The customer charge adopted is $65.00.

The Commission has adopted the same flat energy charge for the summer and winter periods. The Commission does not believe the energy charge increase should be as great as that proposed by Staff or as little as that proposed by UE. Since there is a relationship between the PS rate and the LGS rate, that relationship will be maintained through the energy charge. The LGS energy charge should be set to reflect this relationship. The Commission has determined the energy charge should be increased the first year in relation to the PS energy charge from its current rate of 2.35 cents/kwh, and should increase in increments for each year thereafter during the eight-year phase-in period until it reaches the final amount of 3.502 cents, as set out in the chart in the Summary Of Rate Design.

The Commission has adopted a flat summer demand rate for LGS as it has for the other classes. The summer rate will be determined based upon the winter base rate. The summer demand rate will change each year based upon the differential between it and the winter base demand rate.

The winter base demand rate will be $13.224 at the end of the eight-year phase-in. The current rate is $6.03. The winter base rate will increase in increments each year of the phase-in period until it reaches $13.224.

The winter seasonal rate will be developed based upon the calculation of the winter base rate and the summer demand rate. The winter seasonal rate will change with the other two rates.

The Commission has determined the differential between the summer flat rate and the winter base rate should be 37.5 percent at the end of the phase-in period. The first year differential will be 69.26 percent and the differential will move in equal increments each year of the phase-in period until it reaches the 37.5 percent.

The current differential is 73.8 percent. The Commission has set out a chart in the Summary Of Rate Design section which shows the yearly change in rates.

The Commission has determined, based upon the results of its hypotheticals, that the current rate limiter should be retained. The impact of the substantial increase in this case plus a reduction in the rate limiter would be too severe on those LGS customers affected. The Commission finds the current rate limiter should be retained.

The Commission has also determined that the LGS Class should be structured as follows:

(1) There will be a 100 kw minimum monthly billing demand which will apply to all customers, including those eligible to be billed on the rate limiter.

(2) UE's proposed definition for seasonal demand will be adopted.

(3) There will be a minimum usage level of 100 kw before a customer is eligible to be billed on the seasonal rate.

(4) The 100 kw minimum usage for (3) above is calculated thus:

base demand = 100 kw
seasonal = 0 kw

The Commission bases the four provisions above upon its review of the evidence and the responses to its hypotheticals. The Commission has determined these provisions are reasonable provisions for establishing rates for LGS usage.

K. Primary Service

1. Union Electric

UE proposes a customer charge for Primary Service (PS) of $135.00 a month, a kwh charge of 2.70 cents for all months, a demand charge for the summer period of $19.00/kw and a demand charge of $15.27/kw for the winter period. UE's rate structure for the PS Class is similar to that proposed for the LGS Class. The differences between the two are: (1) the proposed PS rate eliminates the rate limiter entirely, (2) the proposed PS rate has a minimum billing of 100 kw, where LGS has a minimum billing demand of 150 kw, and (3) present time-of-day billing provisions for PS are retained.

UE developed the components in its PS rate in a manner similar to the development of the components in its LGS rate. UE's AE analysis indicated that

38 percent of production costs should be allocated to the summer period and 62 percent to the winter period. UE also considered the revenue impact of the Rider B credits in its proposed PS rate structure. Rider B applies to PS customers taking high voltage service.

UE contends it can eliminate the rate limiter for PS customers, while only phasing it out for LGS customers, because the rate limiter affects a very few customers in the PS Class (approximately one-third of 1 percent as opposed to 1.5 percent for the LGS Class). UE is proposing level rates for the summer and winter demand charge in the PS Class to make the rate structure more understandable to its customers. UE also states that a smaller summer/winter differential is justified for PS customers than for other classes because of the stability of usage over the year.

2. Staff

Staff proposes a customer charge of $135.00 per month, an energy charge for all kwh of 4.536 cents, a summer demand charge for all kw of $11.696 and a winter demand charge for all kw of $10.638. Staff also proposed voltage discounts at different voltage levels. Staff proposed discounts for customers receiving service at the different voltage levels but, based upon an agreement concerning Rider B credits between the Industrials and UE, Staff has dropped this part of its proposed rates.

Staff's seasonal demand charges do not contain a base component. Staff stated it expects base demand for PS customers to equal total demand. Staff asserts the level of cost included in the energy rates for PS customers, if all Callaway costs are included, should be no less than that proposed by Staff if the rates are to be consistent with Staff's TOU/AP cost of service study. Staff states its seasonal rate differentials for PS should be the lower bound for rates. Higher seasonal differentials can be obtained by allocating more distribution costs to the summer period. Staff states it would recommend larger seasonal differentials only if its proposed rates resulted in certain customers receiving significantly higher annual increases than others.

3. Industrials

Industrials propose a $260.00 a month customer charge; an energy charge of 2.61 cents/kwh; summer demand declining block charges of $18.94 for 0 to 1,000 kw, $18.27 for 1,000 to 10,000 kw, and for all above 10,000 kw, $17.57; and winter demand declining block charges of $10.82 for 0 to 1,000 kw, $10.09 for 1,000 to 10,000 kw, and for all above 10,000 kw, $9.34.

Industrials developed these rates based upon their view of the proper allocation of fixed production and transmission costs between demand and energy charges. Industrials made an adjustment for the increase in Rider B voltage level credits. Industrials developed a percentage which they applied to the existing customer charge, to each block of the demand charge, and to approximately 12 percent of the energy charge. A variable component was then added to these figures. The totals were then adjusted to match Industrials' target revenue levels for the PS Class.

Industrials justified the three-step declining block demand charge because of the diversity of customers receiving primary service. Industrials assert that the three-step declining block rates reflect the characteristics of those customers who take service from UE-owned substations and who are thus not eligible for Rider B credits. These customers, Industrials contend, do not impose the same demand-related costs on UE's system.

Industrials propose a $260.00 customer charge based upon UE's cost of service study which, Industrials contend, indicates the customer charge should be over $300.00. Industrials contend that since summer peak causes new capacity, demand charges should be placed primarily on summer demand. Industrials assert any movement to higher demand charges for winter usage would adversely affect UE's load factor for PS customers.

4. Discussion

Below are charts indicating the current rate structure for the PS Class and the proposals made in this case.

Chart A

	Current	UE	Staff	Industrials
Customer Charge	$135.00	$135.00	$135.00	$260.00
Energy Charge: All kwh	2.261¢	2.70¢	4.536¢	2.61¢
Demand Charge:				
Summer				
0 - 1,000 kw	$10.08	$19.00	$11.696	$18.94
1,001 - 10,000 kw	$ 9.72	$19.00	$11.696	$18.27
Over 10,000 kw	$ 9.35	$19.00	$11.696	$17.57
Winter				
0 - 1,000 kw	$ 5.75	$15.27	$10.638	$10.82
1,001 - 10,000 kw	$ 5.36	$15.27	$10.638	$10.09
Over 10,000 kw	$ 4.96	$15.27	$10.638	$ 9.34
Rate Limiter:				
Summer	9.02¢			
Winter	6.11¢			

Chart B

% Differential Summer/Winter	Current	UE	Staff	Industrials
0 - 1,000 kw	75%	24%	10%	75%
1,001 - 10,000 kw	81%	24%	10%	81%
Over 10,000 kw	86%	24%	10%	88%

UE objects to Staff's PS rate structure because of its impact on high load factor customers. UE asserts its allocation method properly reflects increased fixed costs in the demand rate and thus the energy rate is not affected. Under Staff's method the demand charge is not affected but the energy charge is increased substantially. This shift, UE asserts, could have disastrous economic consequence within its service territory.

UE proposes to eliminate the option of the PS customer to be billed on the LGS rate. The elimination of this option makes Industrials' proposals of a $260.00

customer charge unfair to those customers who lose that option. The excess customer costs not collected in the customer charge are collected within the rates. UE contends that this is a more reasonable and fair approach based upon the elimination of the option. UE has proposed reducing the seasonal demand charge differential to 25 percent for the PS Class. Existing differentials are 75 to 90 percent and continuing them would result in a summer demand charge of 25 percent/kw. UE's 25 percent is based upon a reasonable judgment, while Staff's differential is based upon Staff's class cost of service study.

Industrials have proposed that the declining block rate should be retained because of certain economies of scale and the requirement of only a single step down in voltage for the PS customer. UE states that a variety of considerations are involved in determining whether any actual savings exist because of the primary customer taking only a single step down in voltage. Shorter primary voltage lines do exist, but there is probably a longer extension of the 34 kv line where there is the shorter primary voltage line. UE states the major portion of economies associated with serving high voltage customers is the absence of secondary voltage lines, transformers and services. UE contends any savings associated with these costs should be shared within the class because of the overall tradeoff.

The major differences between UE, Industrials and Staff occur over the allocation of fixed production costs to the energy charge. UE and Industrials allocate approximately 15 percent, while Staff asserts its TOU/AP method allocates 50 percent of average costs to the energy charge because those costs are related to average demand.

Staff states that distribution costs have been included in base demand costs in its winter demand costs for PS customers. Without this allocation of distribution costs, the differences between the summer and winter customer rates would be substantially greater. Staff states further that UE's 25 percent differential is not "out of order". Staff is opposed to the elimination of the rate limiter. Staff states the rate limiter is the only mechanism for correcting for the rapid drop in coincidence factor for the low load factor customers.

The Commission restates its adoption of Staff's method overall, and therefore for the PS intraclass rate structure. The Commission has determined that Staff's method properly allocates the costs within the PS Class. Based upon the adoption of Staff's overall method the Commission has found PS intraclass rates should move in the direction of those proposed by Staff. That movement, though, will be tempered by the phase-in period and by customer impact.

The Commission has determined that UE's proposal to eliminate the option of PS customers to take service at LGS rates is reasonable and so will adopt that proposal.

The Commission has determined that Industrials' customer charge is too high, and as UE contends, the higher rate is not justified based upon the elimination of the right of PS customers to be billed at the LGS rate. The Commission adopts a customer charge of $135.00.

The Commission has determined that Staff's method of allocating production and transmission costs is appropriate and reasonable. This means the energy charge for the PS customer will increase more than if Industrials' or UE's method were adopted. The Commission, though, does not believe a full move to Staff's proposal is warranted. The Commission is aware of the impact a higher energy charge will have on PS customers, and therefore has not adopted a full move to Staff's proposed rates. The Commission, though, has proposed a phase-in of this and other PS rates to allow for a reconsideration at some later time.

The Commission has determined the energy charge should be the same for both the winter and summer periods. The Commission has determined the PS energy charge should be set between UE's proposal and Staff's due to the impact a full move to Staff's energy charge would have on PS customers. The Commission will increase the energy rate for the PS customers to 3.38 cents at the end of the phase-in period. To reach the 3.38 cents the energy charge will increase each year of the phase-in period as set out in the chart of the Summary Of Rate Design.

The Commission has determined the final differential between the summer rate and winter rate should be 25 percent as agreed upon by Staff and UE. The current differential is 75 percent. The Commission has determined it should first move all PS customers to the flat winter demand rate the first year. The Commission will adopt the 75 percent differential for the first year differential between summer and winter demand rates. The differential will then move by equal increments each year the remaining years of the phase-in period to reach the 25 percent differential at the end of the phase-in period. The yearly change in rates is shown on a chart in the Summary Of Rate Design section.

As with the LGS Class, the Commission has determined the current rate limiter should be maintained in the PS Class. The Commission has determined this is reasonable based upon the impact the removal of the limiter would have on affected customers.

L. Interruptible

UE's proposed Interruptible Power rate tracks the structure of the PS rate proposed by UE. There is only one customer currently on UE's Interruptible rate, so UE combined the Interruptible rate with the PS Class for all class cost of service studies. The rate value for Interruptible service is the same as for PS rates except the Interruptible demand charge is set at 50 percent of the PS demand charge, which is the firm rate.

Dundee Cement Company is the lone interruptible customer. Dundee accepts the proposal to change the Interruptible rate to 50 percent of summer and winter PS demand charges. Dundee opposes UE's proposal to reduce the differential between summer and winter demand charges. Dundee asserts that UE's proposal would increase current tail block rates for summer usage 103 percent, and 200 percent in winter. Dundee supports the summer peak theory for allocation of demand charges to UE's system. Dundee proposes a winter demand charge increase no greater than that given the summer. Dundee generally supports Industrials' proposals with regard to allocation and rate structure.

Dundee proposes for the interruptible customer that only the months July and August be subject to the higher summer demand charges. Dundee proposes this based upon its own studies which show that UE peaks during either the month of July or August. This proposal would allow Dundee to be charged the winter demand charges during the months of June and September. This proposal, Dundee suggests, would make the Interruptible rate more attractive and other customers might utilize that rate. Dundee also states that this option would improve UE's load factor without increasing demand on the system peak.

Dundee objects to UE's proposal to consider the hours of 10:00 AM to 10:00 PM for purposes of determining billing demands. Dundee's witness analyzed hourly demand data for 1980 to 1983 and found that loads within 95 percent of annual system peak occurred only between 1:00 PM and 7:00 PM. Since these are the hours of peak usage only these hours, Dundee asserts, should be included in the period utilized to measure billing demands for interruptible service. This proposal, Dundee asserts, would make the Interruptible rate more attractive to customers.

Dundee objects to any increase in the interruptible energy charge greater than the annual increases in variable energy related costs. Dundee objects to both UE's and Staff's proposals for increasing Interruptible energy charges on this basis. Dundee asserts that it is in the interests of UE and its customers to encourage as much offpeak load as possible. This should be done by reducing the increase of peak energy charge.

UE states that interruptible customers receive both interruptible and firm service through the same meter and there can only be a theoretical calculation to separate the two services. For this reason UE opposes the 50-percent discount Dundee is proposing for the difference between the Interruptible rate energy charge and the actual fuel costs. UE asserts that interruptible customers are responsible for all local supply facilities as a requirement of the interruptible tariff. On this basis UE objects to Dundee's proposal that Rider B credits be applied to interruptible customers at a 50-percent level. This issue will be discussed later under Rider B.

UE's offpeak provisions allow interruptible and primary customers to increase demands during offpeak hours with no billing penalty. Dundee's proposal to shorten the number of peak hours would thus affect the billing demand charges by both interruptible and primary customers. UE states that Dundee's study of offpeak usage is only a portion of the overall picture. UE asserts hourly incremental running costs should be taken into account for establishing offpeak hours. Based upon incremental running costs UE states significant changes in costs take place between 9:00 AM and 11:00 AM and 9:00 PM and 11:00 PM, resulting in the wider 12-hour band proposed by UE.

UE opposes the limitation of summer demand to July and August for interruptible customers on the basis that the demands in June and September are within 10 percent of the July-August peaks and are significantly higher than the demands for other months in the year. All customers will be utilizing Callaway output and be receiving the benefits of lower energy costs, so all should participate in the costs of Callaway through rates.

Staff asserts its basic position is that the Interruptible rate should be decided between UE and the interruptible customer. Staff proposes a 50-percent reduction in the primary service rate adopted by the Commission as the Interruptible rate. The interruptible demands should be billed at one-half the Primary Service rate. Staff supports the position that voltage discounts should be applied to interruptible customers. Staff witness Proctor states he is not aware of any basis for allocating production capacity costs to the interruptible customer and therefore cannot give any recommendation or correct percentage to the Commission.

The interruptible customer provides a benefit to the UE system by the nature of its service. The interruptible customer may be denied service when UE is unable to meet the total demands of its system at any given time. This allows UE to provide service to its other customers. The possibility of interrupting service usually cocurs during system peaks, but it could also occur during plant shutdowns or other times.

Because Interruptible service is not assured, there is reduced cost associated with providing the service. The Commission has determined that the Interruptible service should be billed at 50 percent of the Primary Service rate for demand charges. The Commission has already discussed the appropriate allocation of costs within the PS Class. Dundee's arguments concerning its service do not change those findings.

The Commission has determined that UE's proposal to consider 10:00 AM to 10:00 PM for purposes of billing demand is the more reasonable. Since Dundee's proposal would affect all PS customers, the Commission does not believe it is reasonable.

The Commission has determined that summer demand for interruptible customers should be June through September. Dundee's proposal to limit the summer demand to July and August does not reflect the peaks on UE's system occurring in June and September.

M. Retained Subsidiaries

On December 15, 1983, the Commission issued its Report and Order in Case No. EM-83-248, authorizing the merger of UE's three subsidiaries into Union Electric Company. In that Report and Order UE was authorized to apply the existing Union Electric rates throughout its service areas, except UE was directed to retain the tariff rates of its former subsidiaries for the following services:

> Municipal fixed rates, municipal service rates, municipal pumping rates, municipal lighting rates, municipal street lighting rates, traffic signals rates, cotton ginning and irrigation rates, irrigation rates, private lighting rates, outdoor lighting rates,

athletic field lights rates and the rates applied to Southeast Missouri State University and Whiteman Air Force Base.

In regard to municipal service tariffs, the Commission stated at page 17 of the merger order:

> By not increasing the municipal tariff rates, the Commission is allowing all municipalities approximately one year to anticipate the possibility of a substantial increase in rates in the future. This increase may result from an application of UE tariffs to the subsidiaries' electric municipal customers and the possible large increase in UE's rates when Callaway One comes on line. UE is planning on filing its next rate case in February, 1984.

In addition, the merger order directed UE to provide cost of service studies relating to municipal service, municipal and private lighting, irrigation, cotton gin and traffic signal rates in its next rate case.

In the instant case, UE has filed cost of service studies as directed by the Commission in the merger case. Based on its cost of service studies, UE contends that all former subsidiaries should be eliminated and those customers placed within UE's general rate classes.

The Staff also recommends the elimination of the former subsidiary rates based on its studies.

Jefferson City, et al., and the City of Cape Girardeau recommend that municipal service be treated as a separate class and therefore oppose UE's proposal that the cities presently being served under the retained subsidiaries rates be placed within UE's major customer classes.

The Commission is not persuaded by the cities' arguments that municipalities are distinguishable from other electric customers such that a separate customer class for municipalities is justified. Electric service is provided to municipalities for such uses as offices, garages, recreational facilities, fire houses, street and signal lighting, and pumping facilities, among others. Such service is supplied to the municipalities utilizing, for the most part, the same common facilities and resources used in serving all other customers on the system. The operating characteristics of such service is not unlike the wide variety of service provided to customers in the private sector.

The municipalities who were Union Electric customers prior to the merger have been served under UE's general rate classification for many years. The Company attempts to offer a manageable number of general rate classifications which reflect a customer's size and delivery voltage.

The cities contend that UE's and Staff's cost of service studies relating to municipalities are inconclusive since the demand allocaters of the various classes to which the cities would be moved are imputed to the municipalities. Thus, the cities argue that the usage characteristics of the Small General Service Class were assumed to be the same as the municipalities without independent verification.

Although it is true that demand allocaters were not developed for the municipalities as a separate class, the load characteristics of municipalities being served under UE's Small General Service, Large General Service and Primary Service tariffs were considered in determining class demand allocaters used in Staff's as well as UE's cost of service studies. Thus, the usage characteristics of municipalities are incorporated in the cost of service studies relating to the General Service and Primary Service Classes. UE was not required to disaggregate municipalities being served under its General Service and Primary Service tariffs for purposes of assessing the reasonableness of its proposal regarding customers presently being served under its retained subsidiary tariffs.

Both Staff's and UE's cost of service studies support the reasonableness of UE's proposal to move the retained subsidiary tariffs to UE's standard General Service or Primary rates.

UE's study shows that within the Small General Service rate class, five of the former subsidiary rate subgroups had rates of return equivalent to or less than the overall General Service Class average and five subgroups were above average. Those with above average rates of return to the Small General Service

Class return were within a range of seven to twelve percent. Staff's study for the Small General Service Class shows rates of return for the former subsidiaries subclasses to be very close to the average Small General Service return with the exception of the cotton gin subclass. The cotton gin subclass shows a return considerably below the class rate of return.

UE's study with respect to Large General Service and Primary Service shows returns of former subsidiary subclasses equivalent to or less than the Large General Service and Primary Service average class rates of return. Staff's Primary subclasses show similar results. However, the Staff's Large General Service subclasses exhibit a fairly broad disbursement around the class average. Staff concludes that since the Large General Service subclasses contain a total of three customers, one of whom may not have been an active customer during the entire test period, the results of the Large General Service subgroup are inconclusive.

In the Commission's opinion it is unreasonable for UE's municipal customers to be served under different rates solely on the basis that one group of municipal customers were once served by UE's former subsidiaries.

The Commission notes that most of the retained subsidiary city accounts fall within the Small General Service Class. In addition, UE states that it is willing to offer time of use features to its Small General Service customers which the cities may utilize to ameliorate the rate increase caused by the elimination of the retained subsidiary rates.

Even though the Commission has previously decided to move all retained subsidiary customers to the current rate classes on UE's system, the Commission feels it would be appropriate to phase in the movement of the retained subsidiary customers in this case to reach the UE class rates. The retained subsidiary customers will move one-half of the way from their current rates to the current UE rates for those classes and will move the rest of the way on the next anniversary of the effective date of this order. The retained customers will, in addition, be given the same percentage increase in rates as that given other members of the appropriate class in this case. The movement of half the difference may be accomplished by retained tariff class rather than individual customer. The shortfall in revenue caused by this phase-in shall be made up within the classes where the phase-in occurs.

N. State of Missouri

The State of Missouri (State) addressed three issues with regard to rate structure in these proceedings. Those issues are: (1) to allow Southeast Missouri State University (SEMO) to receive service under UE's Interruptible rate; (2) to allow customers receiving service at Primary voltage to be billed on UE's Small General Service or Large General Service rates; and (3) to provide conjunctive metering for customers who, through the merger, lost the functional equivalent of conjunctive metering, or, in the alternative, to permit conjunctive metering for customers operating a single enterprise on contiguous properties, whether or not separated by public streets. This applies to the Capitol Complex.

The issue involving SEMO will be discussed below. From the evidence it appears that the issue involving Primary customers taking service at SGS or LGS rates has been resolved. The final issue is that of conjunctive metering for the Capitol Complex.

The Capitol Complex consists of 11 buildings owned by the State right around the State Capitol Building. These buildings are separated by various streets in Jefferson City, Missouri. The buildings have interconnected steam heat and cooling systems. Because of this interdependence State asserts that the buildings in the Capitol Complex cannot be compared to ordinary office buildings. Under the rates of UE's former subsidiary, Missouri Power & Light Company (MPL), State asserts it had the functional equivalent of conjunctive metering, since the total amounts of all bills for the buildings were treated as if all service came through a single meter. The rates did not have demand components.

State contends it did not build its own electric distribution system because of this rate structure. State wishes to receive the same treatment from UE that it received from MPL. Since the merger of MPL into UE, all the buildings now have demand and energy meters. This separate metering, State asserts, creates a situation where the sum of the monthly maximum demand readings for the 11 buildings is greater than the monthly maximum demand of the entire Capitol Complex. Thus, State asserts, it is being penalized by UE's rates. State indicated there were two solutions to the problem: (1) State could construct its own distribution system at a cost of $700,000, or (2) UE could bill the Capitol Complex as if it were conjunctive-metered. State asserts the second alternative would be less costly to the State.

UE's current tariffs only allow accumulated or conjunctive billing where there is a single point of delivery. UE contends for State to be billed as it requests it must build its own distribution system and take service at a single meter. If State builds its own distribution system, UE's revenues would be reduced $173,000 a year.

The Commission does not consider it reasonable to create a special exception for the buildings in the Capitol Complex. If UE's distribution system is left in place, UE has costs associated with that system. Those costs are attributable to the usage of the State. UE says it will remove the existing facilities if State builds its own system. Based upon the figures presented by the State, the cost of a distribution system could be recovered over a few years. The Commission does not consider it reasonable to allow other customers to subsidize the distribution system which serves the buildings in question. The Commission, therefore, will not order a new tariff to allow a conjunctive metering equivalent as requested by State.

O. Southeast Missouri State University

UE proposes to place Southeast Missouri State University (SEMO) on its Primary Service rate. SEMO is presently being served on an Interruptible contract rate. In the merger case, (Case No. EM-83-248), UE proposed to eliminate the contract rate and serve SEMO on UE's 10(M) Interruptible rate. However, in the merger case, the Commission ordered that SEMO's rates be maintained until the effective date of the Report And Order in the next rate case.

UE now proposes that SEMO be served under the Primary 4(M) rate since SEMO does not have the 10 megawatts of interruptible load required under the 10(M) tariff. UE is concerned that other customers having less than 10 megawatts of interruptible load may also request service under the 10(M) tariff. The record reflects that this concern can be eliminated by a revision of the 10(M) tariff to include a provision permitting customers who were served under an Interruptible rate by a former UE subsidiary to continue receiving service under UE's Interruptible rate 10(M) irrespective of the 10 megawatt load requirement.

SEMO is the only Union Electric customer with less than 10 megawatts of interruptible load who was also an interruptible customer of a former subsidiary prior to the merger.

Since SEMO has been an interruptible customer for several years and has incurred investment in generation equipment in reliance upon the availability of 10(M) tariffs, the Commission determines that UE should provide service to SEMO under the 10(M) tariff. The Commission further determines that the tariff should include a provision permitting customers who were served under an Interruptible rate by a former UE subsidiary to continue receiving service under the 10(M) rate irrespective of the 10 megawatt load requirement.

P. Lighting

UE proposes to eliminate the distinction between municipal street lighting and private street and outdoor area lighting in its tariffs. The current tariffs result in different rates for the same fixture. Staff supports UE's proposal to eliminate this distinction. Cities are opposed on the same general grounds as those presented concerning retaining a separate municipal rate. The Commission considers it to be reasonable for UE to eliminate the distinction between private and municipal lighting which resulted in separate rates for the same fixtures. The objections of the Cities are not persuasive on this issue.

Q. Rider B

UE currently has a tariff providing credits to certain high voltage customers who own their own substation equipment. These credits are known as Rider B credits. Industrials propose that Rider B credits not be phased in with the PS rate. UE opposes this since it would affect the PS rate and would be a mismatch of the rates if the PS rates are phased in. The Commission agrees with UE and will phase in Rider B credits with the PS rate phase-in.

Interruptibles propose that Rider B credits be extended to the Interruptible demand charge at 50 percent of the credit allowed firm customers. UE contends this is not appropriate since interruptible customers are responsible for all local supply facilities as a requirement of the Interruptible tariff. UE states interruptible customers already receive a lower rate in exchange for the requirement that they provide their own distribution systems. Based upon the testimony of UE, the Commission finds it is not reasonable to allow Rider B credits to interruptible customers.

R. Rider C

UE proposes to eliminate its ownership of distribution facilities beyond any primary meter. UE states in these instances secondary service is what is actually being provided and the customers should be billed on one of the general service rates. Staff agreed with UE's goal but disagreed with the method UE proposed to reach that goal. Staff proposed certain language to be added to UE's tariff. UE agreed with Staff's proposals concerning the elimination of UE-owned facilities but stated it felt that no additional language was needed in its Rider C tariff sheet. To meet Staff's concerns UE offered certain language which it felt would clarify Rider C in this issue. That language is: "Company shall not be required to provide any distribution facilities beyond the metering point except when required for engineering or other valid reasons." The Commission has determined this language is appropriate and UE's proposal is reasonable.

S. Reconnection Charge

Staff supports UE's proposed increase in reconnection charge from $25.00 to $30.00. The Commission finds the increase reasonable.

T. Special Service Facilities

Staff supports UE's proposed increase in carrying charge for Special Service Facilities from 1.75 percent to 2 percent. The Commission finds this increase reasonable.

U. Summary of Rate Design

The Commission has set out in the previous sections the rate design method adopted for allocating costs among the various classes. The Commission has also set out the rate structure within each rate class for recovering the revenue requirements of each class. The rate structures adopted by the Commission will be phased in over the eight-year phase-in period. The Commission has developed several charts to show the increase in revenue requirements by class each year of the phase-in and the changes in the rates each year of the phase-in.

The first chart shows the current revenue level by class and the increase in revenues for each year of the phase-in. The total revenue requirement at the end of the phase-in is set out in the final column.

The other charts set out the implementation of the changes in rate structure decided in this case. These changes are to be phased in except for the monthly customer charge. The charts show the increase each year in the winter base rate, with the summer rate and winter seasonal rate being a calculation based upon the winter base rate. The energy charges for Large General Service and Primary Service are also phased in. The Commission will order UE to file schedules showing the impact on customers at various usage levels for all classes in years two through eight. If rate structure changes are necessary, these will be ordered prior to the effective dates of the tariffs in future years.

Additional Annual Revenue By Class

	Current	Year 1	Year 2	Year 3	Year 4
Residential	$451,880,000	$ 71,660,218	$ 54,360,689	$ 42,618,322	$ 45,674,417
Small G.S.	142,675,000	13,786,845	10,458,556	7,449,961	7,767,640
Large G.S.	183,899,000	30,604,520	23,216,268	18,576,838	19,992,781
Primary	186,630,000	31,820,461	23,196,225	20,659,056	22,397,132
Lighting	20,982,000	1,576,956	1,196,262	848,823	871,030
Additional Revenue Requirement		149,449,000	112,428,000	90,147,000	96,703,000
TOTAL	$986,066,000				

	Year 5	Year 6	Year 7	Year 8	Total
Residential	$ 48,947,733	$ 52,480,748	$ 0	$ 0	$ 767,622,127
Small G.S.	8,097,624	8,445,944	0	0	198,681,570
Large G.S.	21,514,026	23,161,994	0	0	320,965,427
Primary	24,275,555	26,323,767	0	0	335,302,196
Lighting	900,062	930,547	0	0	27,299,680
Additional Revenue Requirement	103,735,000	111,343,000	0	0	
TOTAL					$1,649,871,000

Phase-in Of Rate Structure Changes By Class

RESIDENTIAL

	Current	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Winter Initial Tail Block Rate	4.75¢	5.50¢	5.99¢	6.34¢	6.69¢	7.04¢	7.39¢	7.70¢	8.00¢
Summer/Winter Differential	97.00%	94.25%	91.50%	88.75%	86.00%	83.25%	80.50%	77.75%	75.00%
Customer Charge	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75	$5.75

SMALL GENERAL SERVICE

	Current	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Winter Base Usage	5.68¢	6.23¢	6.61¢	6.86¢	7.11¢	7.36¢	7.61¢	7.81¢	8.00¢
Summer/Winter Seasonal Differential	142.0%	129.5%	117.0%	104.5%	92.0%	79.5%	67.0%	54.5%	42.0%
Customer Service Charge	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15	$7.15

LARGE GENERAL SERVICE

	Current	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Energy Charge	2.35¢	2.75¢	2.85¢	2.96¢	3.07¢	3.18¢	3.28¢	3.40¢	3.502¢
Winter Base Demand Charge	$6.03	$7.03	$7.83	$8.73	$9.63	$10.53	$11.43	$12.33	$13.224
Summer/Winter Base Differential	73.8%	69.26%	64.73%	60.19%	55.65%	51.11%	46.58%	42.04%	37.50%
Customer Service Charge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00

PRIMARY SERVICE

	Current	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8
Energy Charge	2.261¢	2.65¢	2.75¢	2.86¢	2.96¢	3.07¢	3.17¢	3.28¢	3.38¢
Summer/Winter Differential	75.00%* 81.00%* 86.00%*	75.00%	68.75%	62.50%	56.25%	50.00%	43.75%	37.50%	25.00%
Customer Service Charge	$135.00	$135.00	$135.00	$135.00	$135.00	$135.00	$135.00	$135.00	$135.00

*These are the current differentials for the three-step declining winter rates. These are being changed to a flat rate.

Conclusions

The Missouri Public Service Commission has arrived at the following conclusions.

UE is a public utility subject to the jurisdiction of this Commission pursuant to Chapters 386 and 393, RSMo 1978.

UE'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, and the burden of proof to show that the increased rates are just and reasonable is upon UE.

The Commission may consider all facts which in its judgment have any bearing upon the proper determination of the setting of fair and reasonable rates.

The Commission may accept a stipulation and agreement in disposition of the issues of a rate proceeding when it appears that the proposed settlement is fair and equitable to all concerned.

The Commission may allow a phase-in of an increase in revenue that is primarily due to an unusually large increase in a corporation's rate base. The Commission may in its discretion approve tariff schedules which will take effect from time to time after the phase-in is approved.

Based on the revenue requirement found reasonable herein, the Commission concludes that UE shall be allowed to file revised tariffs designed to increase gross revenues exclusive of gross receipts and franchise taxes by approximately $461,065,000 on an annual basis.

The proposed tariffs shall reflect an eight-year phase-in plan as established in the findings and conclusions herein.

The tariffs authorized herein shall reflect the rate design found reasonable herein.

It is, therefore,

ORDERED: 1. That pursuant to the findings and conclusions in this Report And Order the proposed revised tariffs filed by the Union Electric Company of St. Louis, Missouri, in this case be, and the same are, hereby disapproved and UE is authorized to file in lieu thereof, for approval of this Commission, tariffs designed to increase gross revenues exclusive of gross receipts and franchise taxes reflecting a one-time increase of approximately $461,065,000 on an annual basis.

ORDERED: 2. That Union Electric Company is directed to file tariffs reflecting the phase-in plan authorized herein which will become effective automatically in each year of the phase-in. This results in a total increase of $652,382,000 over the phase-in period.

ORDERED: 3. The tariffs authorized herein shall reflect an increase of $149,449,000 for 1985. $10,869,000 shall be subject to refund pursuant to the true-up Stipulation and Agreement approved herein.

ORDERED: 4. That Union Electric Company shall file with the Commission by April 23, 1985, schedules as late-filed exhibits showing the impact on customers at various usage levels for all customer classes based upon the rate design adopted herein for years two through eight of the phase-in plan.

ORDERED: 5. That the tariffs authorized herein shall reflect the rate design found reasonable in this Report And Order.

ORDERED: 6. That the tariffs to be filed pursuant to this Report And Order under the first year of the phase-in shall become effective for service rendered on and after April 9, 1985.

ORDERED: 7. That the subsequent tariffs approved in accordance with the phase-in plan shall become effective in each subsequent year on April 9. The tariffs reflecting increases under the phase-in plan for years two through eight shall be filed on or before April 26, 1985.

ORDERED: 8. That Union Electric Company shall file tariffs reflecting a 12.49 percent decrease to become effective on April 9, 1993.

ORDERED: 9. That concurrent with the filing authorized herein, Union Electric shall file the information required in Section 393.275, RSMo 1978, Supp. 1984.

ORDERED: 10. That on or before April 30, 1985, the Commission Staff shall file with the Commission a memorandum discussing recommendations, if any, for assuring the adequacy of the Commission's financial Surveillance Reports for Union Electric Company during the phase-in period.

ORDERED: 11. That late-filed exhibits C-271 through C-309 be, and they are, hereby received.

ORDERED: 12. That any objections not heretofore ruled upon are overruled and any outstanding motions are denied.

ORDERED: 13. That this Report And Order shall become effective on the 9th day of April, 1985.

BY THE COMMISSION

Harvey G. Hubbs

Harvey G. Hubbs
Secretary

(S E A L)

Steinmeier, Chm., Musgrave,
Mueller, Hendren and Fischer,
CC., Concur.
Mueller, C., separate concurring
opinion.
Certify compliance with the
provisions of Section 536.080,
R.S.Mo. 1978.

Dated at Jefferson City, Missouri,
on this 29th day of March, 1985.

CONCURRING OPINION OF COMMISSIONER ALLAN G. MUELLER

IN CASE NOS. EO-85-17 AND ER-85-160

I concur in the decision of the Commission. While I believe we have correctly applied existing standards for inclusion of utility plant in rate base, I believe the appropriate legal standard for the future should be one of sharing of risks between shareholders and ratepayers.

As we state in the Report and Order, to avoid monopoly pricing the state regulates a public utility to ensure reasonable rates. Thus, regulation is intended to serve as a surrogate for competition. In a competitive market, however, the investors accept the full risk of management decisions. Under regulation, because of the obligation to serve, the risks should be shared between the investors and the ratepayers. Disallowances based upon the prudent investment theory accomplish this result. However, I believe that the Commission should be more explicit that such disallowances are risk sharing.

The Commission, which is under a statutory duty to balance shareholder and ratepayer interests, realizes that ratepayers as captive customers have no opportunity to exert pressure on a utility to ensure prudent management. On the other hand, shareholders through the vehicle of quarterly reports and annual reports, are apprised of company management decisions as they are being made. Therefore, shareholders have the ability to exert pressure to protect their financial interests, and they also have the responsibility to review and appraise management decisions as to their prudency. The ratepayers can only look to the Commission to protect their financial interest in fair and reasonable rates.

In my opinion, economic risk sharing is a concept that should be utilized by regulatory commissions more explicitly and extensively. The prudent investment theory and used and useful theory may not be adequate to fairly balance the interests of ratepayers and shareholders.