Re Utah Power and Light Company

Intervenors: Committee of Consumer Services, Kennecott Corporation, Utah Farm Bureau Federation, Salt Lake City Corporation, Hill Air Force Base and General Services Administration. Nucor Steel Corporation, Chevron Resources Company, Utah State Coalition of Senior Citizens and Salt Lake Community Action Program, and United States Steel Corporation et al.

Case No. 79-035-12 et al.

52 PUR4th 436

Utah Public Service Commission

March 7, 1983

PETITION for authority to increase electric rates; granted as modified.

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1. Rates, § 266 — Kinds of rates — Load, diversity, and other factors — End-use schedules.

[UTAH] The commission permitted an electric company to effect the consolidation of certain rate schedules, which included the elimination of difficult to administer end-use schedules, to achieve a set of correct, yet simplified, rate schedules that would be easier to administer while ensuring like treatment of like customers. p. 439.

2. Rates, § 143 — Reasonableness — Cost of service — Relationship.

[UTAH] The commission held that for rates to be just and reasonable they should bear a close relationship to the cost of service. p. 441.

3. Apportionment, § 11 — Distribution costs — Demand or customer related — Engineering analysis.

[UTAH] The commission rejected the use of a minimum distribution system for classifying distribution costs, since that system would result in a double allocation of these costs to low-use customers, but found that it would be reasonable, now and for the future, to classify each distribution system account as demand cost or customer cost, based upon engineering analysis. p. 442.

4. Apportionment, § 11 — Distribution costs — Demand-related costs — Coincident versus noncoincident peak methodology.

[UTAH] Based on evidence that the distribution engineer, when designing a particular segment of an electric company's distribution system, used the class coincident peak rather than the class noncoincident peak, the commission agreed that an allocation method should follow closely the way a system was designed and that it might, therefore, be appropriate that coincident peaks be used to allocate distribution costs; however, because no alternative allocation method employing coincident peaks was presented, the commission permitted, as in a previous proceeding, allocation of distribution costs classified as demand on the basis of demand-related production and transmission plant, adjusted for voltage level, pending development of a coincident peak methodology for the company's next rate case. p. 442.

5. Apportionment, § 21 — Variable costs — Coal purchase costs — Energy-related classification.

[UTAH] The commission found that, since an electric company's mining operation was not sized to meet the peak operating mode of the company's generating units but rather was sized to provide a year-round coal supply, the equation of fixed costs and demand costs by which the company sought to classify its captive coal property costs as dem and related, because they were fixed rather than variable as they did not vary with the volume of coal produced, broke down, and that the company should continue to classify these coal property costs as energy related. p. 443.

6. Apportionment, § 10 — Capacity and demand costs — Production plant — Eight-month coincident peak method.

[UTAH] The commission found that the eight-month coincident peak method should be used to allocate an electric company's production plant rather than either the single coincident peak method or the average and excess demand noncoincident peak method, since the eight-month method: (1) analyzed reserve margins, loss of load probability, and probability of contribution to system peak in determining which eight months to include in the computation; (2) better recognized the design characteristics of the company's system; (3) allowed for recognition of the potential for a shift in the occurrence of peaks; and (4) better reflected the cost causation characteristics of the system and of each individual class. p. 446.

7. DefinitionsRate design concepts — Timing of increases — Mitigation or grandualism.

[UTAH] "Mitigation" or "gradualism" is the term applied to the fundamental principle of public utility regulation that abrupt changes in rates should be avoided and that rate increases should only gradually be put into place. p. 449.

8. Rates, § 339 — Electricity — Customer classes — Impact of increase.

[UTAH] Where the purpose of the concept of gradualism had been defined as to avoid abrupt changes in rates occurring as a result of adoption of a particular cost-of-service method in an electric company's rate proceeding, the commission found that to mitigate the impact of implementing the cost-of-service study no customer class should have a rate increase of greater than 15 per cent; the irrigation pumper class rate was limited to a 10 per cent increase, and all classes would share equally in any subsidy remaining as a result of certain classes not being moved to cost of service. p. 449.

9. Rates, § 143 — Cost of service — Relationship of rates to result of study — Implementation goal.

[UTAH] The commission adopted as a reasonable regulatory objective that each customer schedule over time be brought to within a range of plus or minus 10 per cent of relevant cost-of-service study results. p. 452.

10. Return, § 44 — Risks of enterprise — Class returns — Assessment of class risk.

[UTAH] Although the commission recognized that in calculating the rate of return of each class the commission may take into account the risk of each individual class to a utility, it found insufficient evidence to adopt the argument that an electric company's industrial class was more risky than its residential class and requested the parties to address the question of risk in future cases, including whether or not the ratchet currently included in certain of the company's rate schedules for large industrial customers did reduce the risk of those customers to the company. p. 452.

APPEARANCES: Thomas W. Forsgren for Utah Power and Light Company; Gary A. Dodge for mobile home park owners; James L. Barker for Committee of Consumer Services; F. Robert Reeder and Val R. Antczak for Kennecott Corporation et al.; Michael Ginsberg for division of public utilities; Raymond W. Gee for Utah Farm Bureau Federation, irrigation pumpers et al.; Stephen R. Randle for Salt Lake City Corporation; Margo Hovingh for herself; James B. Tadje for Hill Air Force Base and General Services Administration; Robert S. Campbell and Glenn Davies for Nucor Steel Corporation; Robert A. Peterson and James A. Holtkamp for Chevron Resources Company; Bruce Plenk for Utah State Coalition of Senior Citizens and Salt Lake Community Action Program; Peter W. Billings and Kenneth R. Pepper for United States Steel Corporation.

Before Cameron, chairman, and Irvine and Byrne, commissioners.

By the COMMISSION:

Utah Power and Light Company (UP&L, the company, or applicant) is an electric corporation and a public utility operating in the state of Utah. On June 1, 1982, a prehearing conference was held pursuant to notice at the commission's offices in Salt Lake City, Utah. On June 17, 1982, an order was issued by the commission establishing the scope of this proceeding. It was determined in the order that the following issues would be addressed in this phase of the proceeding:

1. The proper classification of customer classes;

2. The company would present the results of its water heating and commercial air-conditioning load management studies as ordered by this commission;

3. The functionalization, classification, and allocation of the costs of the company;

4. The appropriate spread of the revenue requirement among the classes of service of the company, which would be based on an embedded cost-of-service study;

5. The load loss study ordered by this commission would be presented by the company in this

phase of the proceeding;

6. The economic impact of the spread of the revenue requirement would be considered in this phase of the proceeding.

The prehearing order determined that this phase of the case would not deal with rate design issues. The company had not at that date filed the data required by § 133 of the Public Utility Regulatory Policies Act of 1978 which the parties determined was necessary for rate design purposes. The commission notes that the data required by the Public Utility Regulatory Policies Act has been filed by the company and hereby establishes March 31, 1983, as the date of a prehearing conference to schedule consideration of rate design issues. The company is directed to publish notice of the prehearing conference.

This order addresses the general issue of cost of service as well as several issues on the classification and allocation of costs. This proceeding has been a comprehensive airing of different embedded cost-of-service methods. It is the commission's intention in this order to provide guidelines and policies for the company's future cost-of-service studies. It is the commission's intention to establish a method to govern future revenue allocation proceedings. This is not to say that different positions should not and cannot be presented. It is, however, our intention to remove as much as possible the controversy that has existed on the various methods for conducting embedded cost-of-service studies. Any party who proposes alternative methods, except those specified in this order for further study, will have the burden to demonstrate that the methods adopted in the order are unreasonable.

The findings and conclusions on a proper embedded cost-of-service study should not be construed to require this commission to adopt a similar method for rate design purposes. It is our intention to reaffirm our requirement that the company present both a time-differentiated embedded and a marginal cost-of-service study and propose rate designs based on those studies. Adoption of an embedded cost-of-service study for allocation of revenue requirement does not mean that an embedded cost-of-service study is either required or appropriate for rate design.

Findings of Fact and Conclusions

I.

Proper Classification of Classes

1. The company currently has in effect approximately 37 rate schedules. These schedules consist of special contracts, enduse schedules, grandfathered schedules, and the general use residential, commercial, and industrial schedules.

2. Both the company through witness Dunn and the division of public utilities (division) through witness Powell presented evidence proposing the consolidation of certain rate schedules. They propose:

A. That Schedules 1 and 2 be consolidated; and

B. That Schedules 6, 8, and 9 be consolidated to form both a large and a small power schedule without any commercial or industrial distinction.

In addition, during the course of the proceeding the division proposed an investigation of the elimination of end-use schedules and the mobile home park operators suggested that Rate Schedules 25 and 26 be consolidated.

3. Though the evidence in this case took the form of suggestions of what should be done, no party opposed a consolidation of rate schedules.

[1] 4. The evidence in this case indicated that end-use schedules are difficult to administer. For example, approximately 25 per cent of Rate Schedule 2 customers do not have electric hot water heating even though it is required for receipt of service under that schedule. The commission intends to consolidate or eliminate rate schedules where feasible and beneficial. End-use schedules should be eliminated where possible and service provided under appropriate general residential, commercial, or industrial rate schedules. We further find that the company should, where feasible, reduce the number of streetlighting schedules to the minimum necessary to reflect differences in costs. We therefore order the company and the division to present additional recommendations to consolidate or eliminate rate schedules during the rate design phase of this case, and to do so in accordance with our previous order in Case No. 80 999 09. We hope to achieve a set of correct, yet simplified rate schedules that are easier to administer while still ensuring like treatment of like customers. In this context, the commission notes that commercial Schedule 6 must be analyzed to determine whether customers are appropriately classified on that schedule. In particular, the commission finds that the consolidation of Schedules 1 and 2, of 6, 8, and 9, and of 25 and 26 is reasonable and orders that in the rate design phase of this case the company present schedules and rationale to accomplish the purposes of this paragraph.

5. Pursuant to the supreme court's decision in Mountain States Legal Foundation v Utah Pub. Service Commission and our subsequent decision in Case No. 78-035-14, dated February 11, 1982, which implements a phased elimination of special senior citizen Rates 32a, 32b, and 32c, we hereby order the consolidation of Schedule 1 and 32a, Schedule 2 and 32b, and Schedule 5 and 32c. Effective the date of filing new tariffs pursuant to this order, all residential customers will receive service under Schedule 1, 2, or 5, pending our decision on consolidation of Schedules 1 and 2. The final consolidation of senior citizen schedules into general residential schedules was formerly scheduled to occur April 1, 1983.

II.

Load Management

1. On January 16, 1980, this commission issued an order requiring the implementation by the company of load management programs for electric water heaters and commercial air conditioning. The implementation was to occur by January 1, 1981. On May 4, 1982, the company filed a motion to delay the implementation of load management which was granted.

Results of the load management studies conducted by the company and its recommendations were to be presented to the commission in this proceeding.

2. The company has presented evidence that it is not cost effective to proceed with either the water heating or the commercial air-conditioning load management programs at this time.

3. The division through Mr. Powell presented extensive evidence on the company's cost-benefit studies, showing among other things, that the company had erred in its cost-benefit calculations. The division concluded that properly derived cost-benefit ratios for b oth the electric water heating and the commercial air-conditioning load management programs are positive. The division therefore recommended that the company be required to proceed immediately with the implementation of both load management programs. The division was joined in this recommendation by the Committee of Consumer Services and by the irrigation pumpers.

4. The division also presented evidence that the water heating and commercial air-conditioning load management programs had a greater cost-benefit ratio than other company programs either currently in place or proposed for implementation. In particular, the division's evidence shows that the water heating and commercial air-conditioning programs have a greater cost-benefit ratio than the zero-interest loan program proposed by the company in Case No. 80-035-20.

5. The company is required to provide capacity and energy to meet future requirements for service. It is common knowledge and this record demonstrates that the cost of new generating units is significantly greater than the embedded cost of the company's existing units. The company can provide additional capacity and energy to serve its customers in a variety of ways. These include new base-load units, new peaking units, purchased capacity and energy, load management, conservation, and cogeneration. Although this proceeding has yielded evidence on the costs and benefits of load management, a lingering question, which also affects our analysis of these alternatives, concerns the proper basis for calculating the value of benefits. There is much similarity between benefit calculations for load management and the avoided cost determination made, subject to an upcoming thorough review, in Case No. 80 999 06. The subject must be examined further.

6. It is therefore the commission's desire to receive further evidence on cost-benefit calculations for certain company programs, including load management, zero-interest loans, and cogeneration and small power production (PURPA § 210). The commission will establish new proceedings to receive new and additional evidence on these programs. The company will be required to present its recommendations on the proper method of calculating avoided costs, its system avoided costs, and the method for translating avoided costs into rates to be paid cogenerators and small power producers for capacity and energy provided to the company. The company is directed to address specifically the relationship between avoided costs and both the determination of load management benefits and the cost-effectiveness of its proposed zero-interest weatherization loans. All of these programs should be presented to the commission with a view to reduce the cost of additional capacity and energy that the company must provide in the future. The commission will incorporate into this proceeding designated portions of the record in this case on load management and in addition, will consolidate Case No. 80 035 20 on

zero-interest loans with this new docket. The commission informs the company that the proper context for these matters, hinging as they do on the concept of avoided costs, is optimal capacity expansion planning, a subject we intend to explore rigorously. Our point of view is that new generation capacity, private generation (cogeneration and small power production), load management, zero-interest loans, or any other such option should be pursued where a cost savings for the utility and its customers can be achieved.

III.

Cost-of-service Studies

[2] 1. The prehearing conference and order issued on June 17, 1982, stated that this proceeding would utilize embedded cost-of-service studies to spread the revenue requirement among the company's rate schedules. This commission believes that rates, to be just and reasonable, should bear a close relationship to costs of service. Yet in this proceeding more cost-of-service studies have been presented than ever before, thus making our determination exceedingly difficult. Not only is the ap propriate method of deriving cost of service at issue, but many related issues as well, each of which has been the subject of contending expert opinion, and each of which can alter the cost of service of the various classes of service. Issues which must be resolved by this order include the following:

A. The proper classification of distribution costs and how those costs should be allocated to various rate schedules;

B. If the company's coal properties should be classified as demand or energy;

C. The proper load losses to be included in a cost-of-service study;

D. The proper method for allocating production plant to the various schedules;

E. The use to be made of actual data in performing cost-of-service studies when that actual data differs from the data used to establish the revenue requirement for the utility.

2. It was the intention of the commission to allow this proceeding to be a full and complete airing of all views on cost-of-service methods. We believe this proceeding has served that purpose and has provided enough information to permit us to decide upon the proper cost-of-service method. Decisions in this case therefore will be the foundation for future cost-of-service studies the company will present.

A. *Distribution System Costs.*

(1) In this commission's April 12, 1982, order in Case No. 79 035 12 and in its January 16, 1980, order in Case No. 78-035-14, we held that primary and secondary distribution costs (excluding costs of customer service connection, metering, and customer accounts) would be classified as demand costs, and that such costs should be allocated on the same basis as production and transmission demand-related costs.

(2) In the company's cost-of-service study presented in this case, a large portion of distribution costs that pursuant to our earlier order should have been classified as demand costs were instead classified by the company as customer costs. It is the company's position that a significant amount of distribution cost should be classified as customer and not as demand. The company argues that, otherwise, equitable rates will not be achieved because low users will not pay their fair share of the costs of the distribution system. The company argues that a hypothetical minimum distribution system should be employed as a technique for estimating which distribution costs properly are demand costs and which customer costs. Only then, the company argues, will each customer pay an appropriate cost of service.

(3) Both the division witness, Alt, and the Committee of Consumer Services" witness, Coyle, presented evidence opposing the company's proposed treatment of distribution plant.

[3] (4) Division witness Alt presented extensive testimony that the use of a minimum distribution system to classify distribution costs results in a double allocation of these costs to low-use customers. No evidence was presented in this proceeding to the contrary. The division's recommendation to eliminate this problem is to classify each distribution plant account either as customer or as demand, based upon engineering analysis. The division further recommends that primary and secondary distribution plant should be classified as demand cost rather than customer cost. The commission agrees with the analysis of Mr. Alt and will in this order reject the use of a minimum distribution system for classifying distribution cost.

(5) Mr. Alt's testimony as shown on exhibit presents each distribution system account classified either as demand cost or as customer cost. It is the commission's opinion that the division's proposed classification of distribution accounts is reasonable and should be adopted. The commission orders this classification to be used in future cost-of-service studies presented by the company.

[4] (6) Distribution system costs classified as demand costs are allocated by the company to each rate schedule on the basis of each schedule's noncoincident peak. The division, on the other hand, presented evidence t hat the use of a noncoincident peak for this purpose is inappropriate. Dr. Coyle, for the committee, recommended that distribution plant classified as demand be allocated to each rate schedule on the same basis as demand-related production and transmission plant, adjusted for voltage level. In our January 16, 1980, order, we accepted this approach.

Mr. Alt indicated that the distribution engineer when designing the distribution system makes no use of the class noncoincident peak. The distribution engineer instead uses the class coincident peak on that particular distribution system segment. The division, therefore, argues the use of noncoincident peaks for allocating demand costs to various rate schedules should be rejected. The commission agrees that the allocation method should follow closely the way the system is actually designed. It may therefore be appropriate that coincident peaks be used to allocate distribution costs.

(7) The division, however, did not present an alternative allocation method employing coincident peaks, indicating the company did not have sufficient data then available to permit calculation of an alternative to the company's noncoincident peak procedure. For this case, therefore, distribution costs classified as demand will be allocated on the same basis as specified

in our previous orders. For purposes of subsequent cost-of-service studies, however, the commission directs the company in concert with the division to develop an allocation factor which reflects the design characteristics of the distribution system and takes into account coincident peaks of the distribution system.

3. *Coal Properties.*

(1) In its January 25, 1980, order in Case No. 79-035-12, this commission held that for purposes of cost of service among jurisdictions the coal properties owned by the company should be classified as energy-related and not as demand-related costs. In a later phase of the same case, the company, consistent with the earlier order, classified its coal properties as energy related. But in this case the company proposes to classify its coal property costs as demand related and not as energy related. The division through its witness, Mr. Powell, presented evidence that coal properties should continue to be classified as energy-related costs.

(2) The company asserts that coal property costs should be classified as demand related because they are of a fixed, rather than a variable nature. In support of this position, the company argues that these costs are fixed in the sense that they do not vary with respect to the volume of coal produced. As fixed costs, they are properly demand costs. Traditionally, the costs of coal purchased on the market have been classified as energy related, unless a purchase contract specifically treated some costs as demand related. The contract here is purchased coal versus coal produced from the company's own mines, which, the company argues, permits it to classify certain costs as demand-related costs just as they do in the case of, for example, production plant.

(3) The division's evidence shows that costs should not be arbitrarily classified as demand related or energy related simply because they are, respectively, fixed or variable. Instead, Mr. Powell for the division presented evidence to the effect that the purpose of the investment in coal properties must be examined in order to make a proper classification of costs. By contrast, the company merely examines the nature of such costs, calling them fixed and therefore classifying them as demand related. The purpose of the coal mine investment is to provide energy. Were coal to be purchased on the open market, Mr. Powell indicated it would be a textbook example of an energy-related cost. A demand-related cost, on the other hand, is a cost related to providing the company's peak demand. The division argues that the company's coal mines are designed to provide coal for total energy needs and not just peak demand.

[5] (4) The commission finds that the c ompany's coal mining operation is not sized to meet the peak operating mode of the company's generating units, but rather is sized to provide a year-round coal supply. Hence, the equation of fixed costs and demand costs breaks down. For this reason we find the current classification of such costs as energy related should be retained.

C. *Load Losses.*

(1) In earlier spread cases there has been much controversy surrounding what appropriate loss factor should be used by the company in cost-of-service studies. As a result, this commission ordered a study to be conducted by the company to determine the appropriate loss factor for its cost-of-service studies. The company retained Stone & Webster, a consulting firm, to perform the

study. The results of that study were presented by a Stone & Webster representative in this case.

(2) Both the division's and the company's witnesses indicated they believed the method and results of the Stone & Webster study are reasonable.

(3) No other witnesses or parties objected to the method proposed by Stone & Webster.

(4) The results of the Stone & Webster study, however, have not been used to calculate loss factors in the cost-of-service studies presented by any party in this case. The company indicated that the loss factors proposed by Stone & Webster were unavailable in time to use in its cost-of-service study.

(5) The commission is of the opinion that the Stone & Webster method of determining load losses is reasonable and should be adopted. In future cost-of-service studies the commission directs the company to develop its loss factors using the method proposed by Stone & Webster.

D. *Allocation of Production Plant.*

(1) The most controversial issue in this proceeding concerns the choice of method that should be used to allocate production plant. The evidence in this case indicates that more than 50 per cent of the company's costs of service are allocated using a single allocation factor. It is clear that the factor selected to allocate production plant will have a significant impact on the revenue requirement (and rate of return) for each individual rate class. Division Exh 2 S, which is a summary of the proposed increases or decreases of rates to each schedule based on the six proposed allocation methods, shows a major impact on the final results depending on the method selected.

(2) Company witnesses Mr. Dunn and Mr. White advocated the continued use of the company's preferred average and excess demand noncoincident peak method to allocate capacity costs. The witnesses supported this method on grounds that it promotes fairness, by capturing diversity, and revenue stability, an important company objective. According to witness Dunn, this method recognizes that some capacity costs must be assigned on the basis of "time duration of use," which is accomplished by application of jurisdictional load factor to determine the average component of demand. (The Company's preferred method shares the use of load factor for this purpose with Dr. Coyle. Dr. Leininger accomplishes the same end quantifying average demand by application of this method, while Dr. Compton approaches the general problem of assigning some demand costs on a basis other than peak demand through his proposed surplus off-system sales adjustment.) Chevron's witness, Mr. Coulliard, recommended adoption of the company's preferred method for reasons similar to those given by company witnesses. Witness Cicchetti for Nucor, on the other hand, asserted that the average and excess demand noncoincident peak method is conceptually flawed, gives too much weight to average demand, which is the same as an energy allocation, and is a method that has outlived its usefulness with the advent of better load data. He recommended against its use in this case.

(3) Dr. Leininger, witness for Nucor Corporation, advocated a "peak and average" method in which 60 per cent of capacity costs are allocated on the basis of a single coincident peak and 40 per cent on the ba sis of average demand. The particular 60/40 split results from application of the method and not preselection. System load factor is not used for this purpose. Dr. Leininger

asserted his method does a better job of tracking costs than do other methods and better captures the fact that new plant is more costly than is existing plant by assigning more capacity costs to customer classes whose demand necessitates additional plant. By contrast, according to Dr. Leininger, the company's average and excess demand noncoincident peak method yields perverse results since customer classes showing greatest diversity are assigned relatively more capacity costs. The utility's system is designed to meet peak demand, so coincident peaks must be considered in capacity cost allocation. Other criticisms of the company's preferred method are its failure to consider coincident peak; its treatment of customer classes as if they stood alone; and its use of load factor to distinguish between average demand and excess demand. Dr. Leininger also expressed support for a multiple coincident peak approach as an alternative second only to the peak and average method. Because all cost-of-service studies suffer inherent limitations and inaccuracies, Dr. Leininger suggested that a plus or minus 10 per cent "zone of reasonableness" is acceptable for bringing class rates of return to approximate parity with system average rate of return.

(4) Utah Farm Bureau Federation witness Dr. Peterson advocated use of sum of the 12 monthly coincident peaks method to allocate capacity costs. Given the company's system, this method is best for taking account of cost-causation factors. Like Dr. Leininger, he criticized the average and excess demand noncoincident peak approach as conceptionally unsound and capable if yielding spurious results. He also rejected a single conicident peak approach as not reflecting the cost causative characteristics of the company's system. Though all cost-of-service methods are arbitrary, in that they deal with common costs that cannot be directly assigned, a multiple coincident peak approach is preferred by him. The witness indicated that the company's system characteristics dictate the use of 12 monthly peaks, although eight may be acceptable.

(5) Mr. Brubaker, witness for Kennecott Corporation, advocates selection of an allocation method based on system load characteristics in particular, the cost causative peaks. His choice is the five months coincident peak method, using three summer and two winter months. The system planner is concerned with system peaks, the driving force in capacity expansion, according to Mr. Brubaker. From a conceptual standpoint the company's preferred method is inadequate since it allocates some capacity costs on an energy basis (the average demand portion). A further inadequacy of the company's method is its failure to recognize time of use (the timing of demand); hence, without further manipulation of the method's results, it is of no use for time-differentiated rate design. According to Mr. Brubaker, the average and excess demand noncoincident peak method was developed at a time when, unlike now, adequate load data was unavailable. Its strength lay in recognition of this problem and in accounting for class diversity through use of simplifying assumptions. As this is no longer necessary, and as a multiple coincident peak method is in other ways superior, there is no longer a need to employ the company's preferred method. A multiple coincident peak method will assign more demand costs to a class having demand coincident with system peaks than will the company method. Mr. Brubaker agreed that an endeavor to bring class rates of return to within Dr. Leininger's zone of reasonableness is an acceptable regulatory objective.

(6) Dr. Coyle, witness for the Committee of Consumer Services, proposed the use of an average and excess demand single coincident peak method. Dr. Coyle also supports a multiple

concident peak approach for the company's system. Dr. Coy le was indifferent between use of his method and a twelve months coincident peak methods, which he had proposed in a previous case, because both capture peak demand and year-round use of the system as the important cost causative factors. This is crucial in Dr. Coyle's opinion because the company builds only high cost base-load plant, relying on purchases and sales off-system to create a balanced generation system. A method employing fewer than 12 coincident peaks is not so effective in capturing average demand, proceeds on the basis that peak demand is the most important cost causative factor, and therefore is not, in Dr. Coyle's judgment, as acceptable for use in this case as are his chosen methods. Any such method would have to be corrected to allocate capacity costs to customers not on peak.

(7) Dr. Compton, appearing for the division, proposed the use of an eight months coincident peak method. His choice of a multiple coincident peak approach was very much for the same reasons already mentioned in preceding paragraphs. The strong feature of Dr. Compton's work is his procedure for selection of the important monthly peaks. Employing reserve margin, loss of load probability, and probability of contribution to peak measures, Dr. Compton chose eight months as the important ones in a system planning sense. All other witnesses who supported a multiple coincident peak approach stated that this was a conceptually correct means of selecting peak months because it uses factors of direct importance for system planning. Dr. Compton proposed an adjustment to his eight months coincident peak approach in order to account for the company's exclusive construction of base-load plant, the surplus off-system sales adjustment. This is discussed below.

(8) Nucor Corporation rebuttal witness Dr. Cicchetti, recommended choice of Dr. Leininger's approach but also favored the use of multiple coincident peaks (either the Brubaker or Compton methods). Dr. Cichetti criticized the company's preferred method as not reflecting cost causality, and as giving too much weight to energy use (average demand), particularly for high load factor customers. He recommended rejecting it.

(9) This commission has not in the past ordered the use of a particular allocation method, but our order in the "spread of the revenues" portion of Case No. 79-035-12 (April 12, 1982) directed that this current case would be a proper forum to hear all arguments and evidence on the adoption of an allocation method.

[6] (10) In this proceeding three alternative coincident peak allocation methods were presented. This commission finds that the eight-month coincident peak allocation method presented by Dr. Compton has more empirical support than do the others. In selecting the eight methods to be included in the computation, Dr. Compton analyzed the company's reserve margins, loss of load probability, and probability of contribution to system peak. We find that the use of these three criteria to determine which months to include in a coincident peak allocation factor is reasonable.

(11) A coincident peak allocation method is currently used by the company in its Federal Energy Regulatory Commission proceedings.

(12) The commission finds that the coincident peak allocation method recognizes more than any other allocation method the design characteristics of the company's system. The company

builds only base-load generating units and relies on off-system purchases to meet its peak loads. Several monthly peaks, including a significant winter load, influence capacity planning and system expansion. We are persuaded that an allocation method must capture these, the cost causative, factors of system design. Given this, the company's average and excess demand noncoincident peak method, penalizes off-peak users.

(13) The commission finds that use of a single coincident peak, as is proposed by Dr. Leininger and Dr. Coyle, is inappropriate. The company system does not have a predominant summer peak. Significant load is pla ced on the company's system in the winter. Further, the commission finds that the use of a single coincident peak can result in unstable cost-of-service results. A single peak can vary from year to year, occurring in July one year and possibly in August next year. In addition, the potential exists that the peak which currently occurs in the summer may shift to the winter. Such shifts in peak could result in dramatic changes in cost of service for any individual rate schedule.

(14) The commission finds that the use of an average and excess demand noncoincident peak allocation factor is inappropriate. This method assumes that each class stands alone and that the utility system is built to serve that class and that class alone. The class's individual peak (the noncoincident peak) is included in the calculation formula regardless when it ocurs, with the result that insufficient attention is paid to the contribution of each class to system peak. An allocation method based on noncoincident peaks cannot reflect the cost-causation characteristics of the system and of each individual class as well as can a method using coincident peaks. In addition, a multiple coincident peak method is able to take diversity into account better than can the average and excess demand noncoincident peak method. In fact, the evidence indicates that a coincident peak allocation method directly measures diversity among classes whereas an average and excess demand noncoincident peak allocation method is based on an assumed relationship between class noncoincident peak and system peak.

(15) One drawback of a coincident peak allocation method is its failure to directly recognize the energy savings that occur as a result of the large base-load generation units the company operates. These savings are purported to be recognized in the company's, Dr. Coyle's, and Dr. Leininger's methods. Dr. Compton proposed a surplus off-system sales adjustment as part of his eight months coincident peak method as a means of dealing with these savings. The commission finds insufficient conceptual and factual support in this record for any of these approaches, which amount to an implied classification of production costs as partially demand related and partially energy related, and so at this time will not adopt them. We are convinced, however, that a production plant allocator should recognize that capacity costs have been incurred to reduce fuel costs in the company's base-load system. Classification of production plant as energy related in part is one means of doing this as is the use of an allocator that splits demand into average and excess components (the implicit classification). Our problem with the latter approach is the absence of compelling economic justification in support of the particular "split" proposed by the company, by Dr. Leininger, or by Dr. Coyle. Dr. Compton's "surplus off-system sales adjustment," while conceptually attractive, is insufficiently refined to permit application in this case.

(16) The commission will adopt the eight months coincident peak allocation method to

allocate the company's production plant costs. The commission directs the company to base its future cost-of-service studies on this method. In the future, a party seeking to alter the eight months coincident peak approach we herein adopt will have the burden of showing such alteration to be reasonable based on empirically supportable changes in the factors describing the company's operations that we have relied upon in reaching our decision in this case.

E. *Surplus Off-system Sales.*

(1) The division through Dr. Compton proposed that off-system sales profits be allocated to the class that because of its load factor permitted off-system sales to occur. Although it seems fair that the profits of surplus off-system sales be allocated to the class that permits such sales, the evidence does not indicate that Dr. Compton's proposal accomplishes that purpose.

(2) The surplus off-system sale propo sal did not track on a time-differentiated basis the actual load patterns of customers. In order to accurately estimate the benefits to each individual class of off-system sales, each class's load factor and usage would have to be measured on a time-differentiated basis. In addition, the surplus off-system sales adjustment must be considered in conjunction with the company's balancing account if it is to function properly. For such reasons, the commission will reject the surplus off-system sales adjustment proposal at this time, although this adjustment could be, if properly supported, a refinement to the cost-of-service method we adopt by this order. The surplus off-system sales adjustment also could be considered as a potential refinement to the company's balancing account procedure.

F. *Use of Actual Data.*

(1) All of the studies presented in this case, with the exception of Dr. Coyle's "actual" study, employ the same forecast data used to establish the company's revenue requirement in the preceding phase of this case.

(2) The record is clear that as a result of economic conditions actual company sales differ from what was forecast in the revenue requirement phase. Dr. Coyle urges in particular that actual sales to industrial customers be taken into account in determining the revenue burden industrial customers are to face. Moreover, the Committee of Consumer Services, through Dr. Coyle, suggests that industrial sales are more volatile than sales to other classes, as evidenced by the difference between forecast and actual sales in this case, and therefore industrial customers pose a more significant risk to the company than do, for example, residential customers. The committee urges this risk be taken into account in determining the revenue requirement for each individual rate schedule.

(3) Conditions which cause differences between forecast and actual data are accentuated by long lag times between the revenue and the cost-of-service/rate design phases of the case. The commission is of the opinion and finds that in the future the company and all other parties should strive to have the revenue requirement phase of rate cases and the cost-of-service/rate design phase of rate cases either heard at the same time or closely together. We therefore direct that for the company's next general rate case, after the date of this order, its cost-of-service studies, rate design, and proposed allocation of revenues among classes be filed at the time the company

requests rate relief. It is the commission's intention to avoid rate increases either as a result of interim increases or final orders that do not reflect the cost-of-service study we have adopted in this order. Since the revenue requirement for the company has already been established, the commission is of the opinion and finds that it is appropriate for this case to use in calculating cost of service the data used by the company in establishing the revenue requirement for the company. The purpose for the cost-of-service phase of a proceeding is to take the revenue requirement determined reasonable by the commission and allocate that revenue requirement among the various rate schedules. By using actual data the revenue requirement determined to be just and reasonable by the commission in this case would not be allocated among the various rate schedules on the same basis as that on which the revenue requirement was determined.

(4) The commission does not believe that actual data should be ignored in cost-of-service proceedings or in rate cases. We directed Utah Power to file quarterly reports showing a comparison of forecast sales, revenues, expenses, and rate base with actual sales, revenues, expenses, and rate base. The company should include in this quarterly filing an explanation of any variances from its forecast. In addition, the company shall file with the commission any revisions to the forecast that have resulted from actual data being made available or from changes in condition in the general economy. T he company and the division should jointly develop the format and content of this report.

IV.

Implementation of Cost-of-service Study

[7] 1. Section 54 3 1, Utah Code Annotated, states:

"The scope of definition "just and reasonable" may include, but shall not be limited to, the cost of providing service to each category of customer, economic impact of changes on each category of customer, and on the well-being of the state of Utah, methods of reducing wide periodic variations in demand of such products, commodities or services, and means of encouraging conservation of resources and energy."

This section permits this commission to take into account the economic impact of rate increases on various categories of customers. In addition, it is a fundamental principle of public utility regulation that abrupt changes in rates should be avoided and rate increases should only gradually be put into place. In this proceeding this concept has been referred to as mitigation or gradualism. However, as the concept is defined, the purpose of gradualism is to avoid abrupt changes in rates as a result of adopting a particular cost-of-service method in this proceeding.

2. In various other proceedings the commission has adopted the concept of gradualism. In the commission's April 12, 1982, order rate increases were limited to 15 per cent, even though the cost-of-service studies would have required a more substantial rate increase for certain customer classes. In reintroducing parity to senior citizen rates and normal residential rate schedules this commission limited the rate increases of senior citizens to a particular percentage and gradually have phased the senior citizen rate increases to the normal residential schedules.

[8] 3. Evidence has been presented by various witnesses proposing particular methods to mitigate the impact of this proceeding. We find that no customer class should have a rate increase greater than 15 per cent as a result of implementing this cost-of-service study. In addition, we find that the class rate increase to Schedule 10 should be limited to 10 per cent. These increases will allow gradual movement of classes above 15 per cent toward cost of service. We further find that all other classes should equally share in any subsidy that remains as a result of certain classes not being moved to cost of service. Although it is the commission's intention to move all classes to cost of service no formal implementation of additional rate changes will occur until the next cost-of-service study has been presented. The following table provides per cent increase or decrease in revenues as a result of this order. This table is based on our findings as to appropriate functionalization, classification, and allocation of costs that we have found to be just and reasonable. In addition, this table combines the senior citizen schedules into Schedules 1, 2, and 5, which was scheduled to occur on April 1, 1983. This order limits rate increases to 15 per cent except for Schedule 10, which is limited to 10 per cent. No limit was placed on rate decreases, except that all nonmitigated schedules share equally in the subsidy of those limited to a 10 or 15 per cent increase. The per cent increase or decrease should be applied to all components of each rate schedule equally. The increases or decreases shown on the table shall be

[Table below may extend beyond size of screen or contain distortions.(line lenth=202)]

Decription Requirement	Rate Schedule Designation	Per Cent Change In Schedule Revenue
	1	Residential
(0.31)*	2	Residential with Water
Heating 1.49*	5	Residential
All-electric 2.45*	25	Mobile Homes
(28.22)	26	Existing Mobile Homes
(13.11)	Commercial Sales	Supplemental Energy
	Commercial Sales 4	Commercial Water
Heating 15.00	6	General Service
1.34	19	Commercial and
Industrial Space Heating 14.35	22	Apartment Halls and
Basements 15.00	24	Wholesale Apartment
House Service 15.00	Industrial Sales 6	General Service

5.02
8 Industrial Medium
Voltage
14.88
9 Industrial High Voltage
(1.47)
10 Irrigation
10.00
19 Commercial and
Industrial Space Heating
15.00
21 Steel Furnace
15.00
30 Industrial Service
Large
(18.08)
Great SL Minerals Spec.
Contract
7.54
Kennecott Copper Spec.
Contract
(13.52)
U. S. Steel Spec.
Contract
(12.97)

Public Street and Highway Lighting

6 Traffic Signals
(46.56)
11 Streetlighting Company
Owned
(22.90)
12 Streetlighting Customer
Owned
(56.68)
13 Streetlighting
Telluride Service Area
15.00
60 Haxton Pl. Contract
15.00
61 Salt Lake County
(28.18)

Other Sales to Public Authorities

17 State of Utah
15.00
20 Service to Federal
Installations
4.68
50 University of Utah,
Utah State University, and Weber State College Contract Rates
4.61

Security Area Lighting

7 Security Area Lighting
(32.31)
18 Security Post Top
Lighting
4.27
77 Security Lighting
Contracts
(44.20)

* These numbers result from having combined Schedule 1 and 32(a),

Schedule 2 and 32(b), and Schedule 5 and 32(c). The actual change for the customers currently in these schedules is as follows:

[Table below may contain distortions.]

1	Residential	(0.68)
2	Residential with Water Heating	0.27
5	Residential All-electric	1.89
32(a)	Senior Citizen Rate	3.75
32(b)	Senior Citizen Rate with Water Heating	5.60
32(c)	Senior Citizen Rate, All-electric	10.43

applied to the May 22, 1982, Tariff No. 29 rate levels and then the across-the-board increase authorized by order dated November 8, 1982, shall be applied to the adjusted May 22, 1982, Tariff No. 29 rate levels.

4. The commission takes notice that on February 28, 1983, Salt Lake City Corporation filed with this commission a separate petition to implement, on a summary basis as part of this order, certain pricing changes within streetlighting Schedules 11 and 12. Salt Lake City's verified pleadings allege, inter alia, that:

(a) Pursuant to a joint cost study performed by the division and the company, which has been reviewed and accepted by Salt Lake City, the rates for sodium vapor, mercury vapor fluorescent, and incandescent lights contained within Schedules 11 and 12 are seriously out of alignment with costs, ranging from more than a 23 per cent overcharge for some sodium vapor lamp rates, to an undercharge of as much as 66 per cent for some incandescent lamps. The percentages shown, in Salt Lake City's application, for individual lamp prices would be subject to some small adjustments as the intraclass cost-of-service study is adapted to the overall cost-of-service findings and conclusions contained in this order.

(b) The company, the division of public utilities, and Salt Lake City are in agreement that the prices for streetlights within Schedules 11 and 12 should be adjusted to reflect cost of service pursuant to the joint cost study methodology mentioned above.

(c) Considerable rate instability within Schedules 11 and 12 would result if the rate reductions herein attributable to revenue spread considerations were placed into effect now, followed some time later by an order approving intraclass cost-of-service price adjustments. Under such circumstances some streetlighting customers would experience a sizable reduction in rates one moment, followed by a sizable increase in rates the next.

(d) This rate instability can be avoided by implementing the interclass revenue allocation adjustments and the intraclass revenue allocation adjustments and the intraclass cost-of-service price adjustments at the same time, allowing many of the resulting lamp price increases to be offset against decreases otherwise arising from this order.

(e) The intraclass revenue allocation adjustments for Schedules 11 and 12 will not result in any increase or decrease in the overall revenues or rate of return for either those rate classes or for the company generally.

5. The commission further finds that the cost-of-service study mentioned was developed by the division for Schedules 11 and 12 pursuant to Par 8 of our April 12, 1982, order in Case No. 79-035-12, now consolidated into this docket, as alluded to by the division's witness Mr. Alt in this proceeding.

6. The commission concludes from the foregoing that the lamp prices for streetlighting Schedules 11 and 12 are unjust and unreasonable because they substantially depart from cost. Further, the customers receiving service under said schedules are, overall, best served by implementing the revenue allocation and intraclass cost-of-service pricing changes at the same time, thereby eliminating unstable fluctuations in prices that may result in widespread misunderstanding and mistakes in planning and budgeting by many municipalities that are not aware of these proceedings.

7. In light of such considerations the commission believes that it is reasonable to adopt the joint cost-of-service study for Schedules 11 and 12 and to implement on a summary basis the intraclass pricing changes indicated, to be effective concurrent with other rate adjustments ordered herein. Salt Lake's petition is hereby incorporated into this docket, and any customers receiving service under Schedules 11 and 12 that desire to protest or otherwise address the intraclass cost-of-service study and pricing changes adopted pursuant thereto shall submit such matters as part of the rate design portion of these proceedings to be scheduled as provided above. Any tariff amendments to Schedules 11 and 12 that the company deems appropriate to handle requests for service conversions under said schedules shall be included in the tariff to be filed pursuant to this order, and any objections thereto shall be presented for consideration as part of the rate design portion as well. Conversion priority should be guided by two principles those customers who first request changes, and those customers who are most adversely affected by the intraclass pricing adjustments.

8. During the course of this proceeding the irrigation pumper class requested that consideration be given to implementation of time-of-day rates for that class. The time-of-day rate proposal of the irrigation pumpers was to allow the irrigation pumpers a choice between time-of-day rates and load management which was scheduled to be implemented in the summer of 1983. Both the use of time-of-day rates for the irrigation pumpers and the implementation of load management for that class will be considered in the rate design portion of this case. As a result, the load management program scheduled to be implemented in the summer of 1983 will be deferred until 1984 and the commission will limit the rate increase to the irrigation pumper class to 10 per cent in this case. This limitation is intended to mitigate the rate increase to that class until an opportunity exists for the class to shift load off of peak periods and thus reduce its cost of service.

[9] 9. The results of this case bring most customer schedules near the co mpany average rate of return and thus bring most customer schedules to cost of service. The study of cost of service is not an exact science, and thus, we find we have no obligation to bring each schedule to the precise results of a particular cost-of-service study. Dr. Leininger, who testified on behalf of Nucor, indicated that bringing a schedule within plus or minus 10 per cent of company average rate of return is reasonable. We adopt as a reasonable regulatory objective that each customer schedule over time be brought to within a range of plus or minus 10 per cent of relevant

cost-of-service study results.

[10] 10. In calculating the rate of return of each class the commission may take into account the risk of each individual class to the company. Dr. Coyle presented testimony that the industrial class is more risky to the company than is the residential class. We find that insufficient evidence exists in this record to adopt that principle. We request the company, the division, the committee, and any other party to present evidence in future cases to address the question of risk. In addition, we request parties to address whether or not the ratchet currently included in certain rate schedules for large industrial customers does in fact reduce the risk of those customers to the company.

11. In previous actions the commission considered the rates charged by mobile home park operators to tenants. We precluded price manipulation which might create windfall profits for operators by establishing tariffs which prohibited the company from selling for resale to any mobile home park operator whose rates to tenants exceeded that which such tenants would pay if served under residential schedules. This arrangement functioned to the general satisfaction of all concerned until the commission issued its order on April 12, 1982, in Case No. 79-035-12. As a result of that order some mobile home park operators were charged a greater amount than they could collect from tenants under the residential schedule limits. As a result, some park owners were subsidizing the service of their tenants. This result was not intended by the commission, and the error should be rectified. The company filed an amended tariff for Schedule 25 and 26 customers which corrected the problem on a prospective basis. However, between the period May 22, 1982, and November 1, 1982, the sum of $4,291.10 was overcollected as a result of the tariff discrepancy. Accordingly, the company is ordered to calculate the appropriate amount of the overcollection for each park owner on said schedules and make a refund of same to the particular park owners who paid the overage.