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Decision 92-06-020 June 3, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

In the Matter of the Application of SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E) for Authority to Increase its Authorized Level of Base Rate Revenue Under the Electric Revenue Adjustment Mechanism for Service Rendered Beginning January 1, 1992 and to Reflect this Increase in Rates.	Application 90-12-018 (Filed December 7, 1990)
And Related Matters.	I.89-12-025 (Filed December 18, 1989) I.91-02-079 (Filed February 21, 1991)

(See Decision 91-12-076 for additional appearances.)

Michael Mackness, Attorney at Law, for Southern California Edison Company, applicant.

Levy, Samrick & Bernard, Inc., by William G. Fleckles, Attorney at Law, for California Travel Parks Association; Graham & James, by Peter W. Hanschen, David J. Marchant, and Martin A. Mattes, Attorneys at Law, and Steven Moss and Michael Boccardo, for Agricultural Energy Consumers Association; K. Justin Reidhead, Attorney at Law, for Toward Utility Rate Normalization (TURN); Bob Roberts, for Mt. High Ski Resort and Snow Valley Ski Resort; B. L. Griffiths, for Gregg Industries; and E. D. Yates, for California League of Food Processors; interested parties.

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SEVENTH INTERIM OPINION: PHASE 2 ISSUES

1. Summary of Decision

This opinion decides Phase 2 issues (revenue allocation and rate design) in Southern California Edison Company's (Edison) test-year 1992 general rate case (GRC). It reallocates responsibility for collection of the revenue requirement among Edison's customers but it does not change Edison's authorized revenue requirement for 1992. Rate revisions authorized by this decision are scheduled to become effective June 7, 1992.

We affirm our commitment to the policy of marginal cost-based ratemaking. Using the unit marginal cost calculations and methodology adopted in Phase 1 of this GRC, we apply marginal cost principles to allocate Edison's revenue requirement to customer classes and to design rates for individual rate schedules within each class. We also continue to rely on other ratemaking principles such as rate stability as we evaluate the impacts of marginal cost-based rate changes on customers. For example, we temper cost-based rate adjustments by adopting limits on the increase in revenue responsibility that will be assigned to customer classes.

The adopted revenue allocation for Edison's major customer groups is summarized in the following table.

Revenue Allocation Summary

(x$1,000)

Customer Group	Former Prior to 1/20/92	Present Effective 1/20/92	Adopted Effective 6/7/92
Domestic	2,610,411	2,678,742	2,716,250
Lighting-Small-Med. Power	2,750,878	2,834,257	2,881,060
Large Power	1,683,067	1,684,563	1,577,796
Agricultural & Pumping	215,394	219,430	224,748
Street & Area Lighting	69,031	62,168	67,322
Total	7,334,959	7,479,160	7,479,160

The adopted revenue allocation is generally reflective of marginal costs with the exception of certain Agricultural and Pumping (Ag & Pumping) rate schedules. Increases allocated to those schedules are limited due to our concerns about significant rate impacts.

We also apply marginal cost principles in designing rate structures for individual tariff schedules and establishing the levels of each rate component. We do so with the recognition that some of Edison's approximately 50 rate schedules are far from being cost-based. In some cases, tariff charges are significantly below their corresponding marginal cost values. Thus, we provide for significant but moderated increases in these charges. In other cases we approve the termination of tariff schedules that are no longer cost-justified.

Residential rates are increased by an average of 1.4%. Residential rate structures including the baseline program remain largely unchanged, but the minimum charge will be increased in stages from 10¢/day to 15¢/day over the next three years. A new submetering option is adopted for month-to-month tenants in recreational vehicle (RV) parks. The discount provided to mobilehome park operators with submetered distribution systems is reduced from 21¢/day to 17¢/day.

Finally, the tariff structures for commercial, industrial, agricultural, pumping, and streetlighting customers are revised. The interruptible program, which allows larger customers to receive lower rates in return for their agreement to curtail their peak demand when conditions require, is continued and refined.

2. Procedural Background

Phase 1 issues, including Edison's test-year 1992 base-rate revenue requirement and marginal cost issues, were decided by Decision (D.) 91-12-076 dated December 20, 1991. The procedural background for this consolidated proceeding is described in detail in that decision.

The revenue requirement revisions ordered in the Phase 1 decision were consolidated with revisions from other proceedings, including Energy Cost Adjustment Clause (ECAC) and cost of capital changes, in Application (A.) 91-05-050, Edison's recent ECAC application. The Commission adopted a consolidated 1992 revenue requirement of $7.479 billion by D.92-01-018 dated January 10, 1992. The allocation of that revenue and the design of rates to collect that revenue are at issue in this proceeding.

Public participation hearings which included public statements on both Phase 1 and Phase 2 issues were held before Administrative Law Judge (ALJ) James Weil and ALJ Mark Wetzell in March 1991. In accordance with the Rate Case Plan (RCP),[1] as modified for this proceeding,[2] Edison served its Phase 2 testimony on March 7, 1991 and updated it on July 12, 1991. Division of Ratepayer Advocates (DRA) served revenue allocation and rate design testimony on September 10, 1991, and other parties served their testimony on October 21, 1991.

A Phase 2 prehearing conference was convened on October 25, 1991. Fourteen days of evidentiary hearings were held before ALJ Wetzell during November and December of 1991. Concurrent opening and reply briefs were filed on January 8 and 21, 1992 respectively. Phase 2 was submitted on February 14, 1992 with the receipt of late-filed technical update exhibits. Parties were allowed to file these exhibits to incorporate recent Commission decisions which impact Phase 2 determinations, including both the Phase 1 decision (D.91-12-076) and the ECAC decision (D.92-01-018).

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1 30 CPUC 2d 576, 601 (1989).

2 Executive Director's letter to Edison dated October 5, 1990 and ALJ Rulings dated February 1, 1991 and December 24, 1991.

Phase 2 was reopened by an ALJ Ruling dated April 16, 1992 to receive a late-filed exhibit on revenue allocation. By D.92-05-071 dated May 20, 1992, the Commission decided a Phase 2 issue regarding payments made by Edison to Qualifying Facilities. This opinion decides all other Phase 2 issues.

In addition to Edison and DRA, parties who actively participated in Phase 2 were Agricultural Energy Consumers Association (AECA), Association of California Water Agencies (ACWA), California City-County Streetlight Association (CAL-SLA), California Farm Bureau Federation (CFBF), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA), California Travel Parks Association, Inc. (CTPA), Cogenerators of Southern California, Federal Executive Agencies (FEA), Industrial Users (IU), Toward Utility Rate Normalization (TURN), and Western Mobilehome Association (WMA).

Comments on the ALJ's proposed decision were filed by AECA, CAL-SLA, CFBF, CLECA, DRA, Edison, FEA, TURN, and WMA. Replies were filed by CLECA, DRA, Edison, FEA, and IU.

3. The Ratemaking Process

3.1 Ratemaking Goals

Once a utility's revenue requirement is determined, it is necessary to establish a rate structure which will enable the utility to collect that revenue from its customers. For electric utilities, a fundamental fact which underlies the process of setting rates is that the costs of providing service vary with the amount of energy consumed; with when, for how long, and at what rate electricity energy is consumed; and with the facilities that the utility must provide to serve a customer. We have found that it costs the utility more to deliver a kilowatt-hour (kWh) of energy during periods of peak demand than it does during off-peak periods. Similarly, it costs more to deliver a kWh of energy at service-level voltage to a residential customer than it does to deliver a kWh at transmission voltage to a large industrial customer.

It would be both economically inefficient and unfair to customers to ignore this fundamental fact and set rates by simply dividing the revenue requirement by the forecast of kWh to be sold, and charging all customers the same flat rate per kWh. An ideal electric rate structure should:

- o Reflect the different costs of serving different customers at different times;
- o Promote system and overall economic efficiency by including understandable "price signals" which (1) inform customers of the costs they impose on the utility by their consumption practices and (2) customers can actually respond to through changes in their consumption practices;
- o Promote efficiency by discouraging uneconomic bypass by customers who have alternatives to taking service on the utility system;
- o Remain reasonably stable over time so that customers who make investments in facilities, equipment, and practices that affect consumption in response to price signals are not unduly harmed as cost measurements and pricing signals change;
- o Be accepted by customers as fair and reasonable;
- o Collect no more and no less than the utility's adopted revenue requirement while providing a stable revenue flow; and
- o Promote and implement goals and programs such as energy conservation and assistance to low-income customers.

It is our goal in electric utility ratemaking to establish a rate structure with these attributes, but reaching that goal can be difficult for a variety of reasons. These include the fact that precise measurement of costs cannot always be attained and the fact that the above attributes sometimes conflict with each other.

3.2 Establishing Edison's Rate Structure

Establishing a rate structure for a utility like Edison is usually accomplished in two basic steps of revenue allocation and rate design. Revenue allocation is generally described as the process by which adopted revenue requirement is divided up among the various customer classes (inter-class) and among schedules within a customer class (intra-class).[3] Groups of customers with similar load characteristics and similar methods of taking service are identified and revenue responsibility is allocated to each group. Edison's major customer groups are Domestic, which includes multifamily residential customers and mobilehome parks; Lighting, Small and Medium Power (LSMP); Large Power (LP), which consists of customers with demands of more than 500 kilowatt (kW); Ag & Pumping; and Street & Area Lighting (SL). For revenue allocation purposes some groups are subdivided into subgroups or rate groups. As discussed below, identification of certain rate groups for revenue allocation purpose was an issue in this proceeding.

The second step is rate design. This is the process of further allocating each group's revenue requirement to individual rate schedules and determining the component rates and charges (such as energy, demand, and customer) and the dollar values for those rates and charges for each schedule. Each of the major rate groups identified for revenue allocation has associated with it several rate schedules. Edison has established a total of approximately 50 rate schedules.

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3 As we noted in Pacific Gas and Electric Company's (PG&E) last GRC, intraclass revenue allocation and rate design overlap somewhat. (34 CPUC 2d 199, 340 (1989).) Thus, intraclass revenue allocation is sometimes characterized as a rate design function.

3.3 Marginal Cost Ratemaking

In the last decade the Commission has adopted and made considerable progress toward achieving the goal of marginal cost ratemaking for both revenue allocation and rate design. The Commission concluded more than four years ago in Edison's last GRC that "[m]arginal costs should continue to be the basis for the revenue allocation and rate design adopted in this proceeding."[4] The discussion in that decision elaborated on this principle:

> "It has been the Commission's long-held view that by using marginal costs in ratesetting each customer will be provided the most accurate price signals regarding his consumption. Not only will this promote conservation and the efficient use of resources, but equity will be achieved by the utility recovering the costs of providing service to each customer in proportion to the costs that customer imposes on the utility system. By providing such cost-related rates, it is additionally our hope that the uneconomic bypass of the utility system by customers with the capability of self-generation will be averted."[5]

We affirm the use of marginal costs for setting rates in this proceeding. No party has contested the basic principle of using marginal costs as the basis for setting Edison's rates. The disputes in this proceeding were largely centered on implementation issues, including the degree to which the setting and revision of rates on the basis of marginal costs should be tempered to reflect ratemaking objectives such as rate stability.

When the Commission uses marginal costs to establish rate structures for electric utilities, it relies on sophisticated analytical techniques which are intended to assess how customers'

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4 26 CPUC 2d 392, 610; Conclusion of Law 107 (1987).

5 Id., 486.

consumption of electricity affects the utility's cost of meeting that demand. Yet, even though powerful computer models have become indispensable ratemaking tools, the use of these techniques has its limits. Ultimately, it must be tempered by the Commission's judgment of what is fair and reasonable in assigning and allocating cost responsibilities among customers. That is why, for example, we mitigate the bill impacts that would result from marginal cost-based rates with such measures as caps on class revenue allocations and bill-limiter provisions in rate schedules. Thus, while marginal costs are our primary focus, they are not the sole determinant of rates.

There are several reasons why marginal costs should not be the sole determinant of electric rates, including variability of marginal costs and reliability of the measurements. An electric utility is a dynamic system subject to changes affecting supply and demand, including changes in the number and mix of customers; overall economic activity; energy market conditions; weather; technological development; environmental, safety, and economic regulation; and a host of other factors. Marginal costs will mirror the impacts of all of these changes on the system and, therefore, can be quite variable over time.

While it is generally appropriate that marginal costs changes be reflected in tariff rates, the frequency of such tariff changes may sometimes exceed the ability of customers to understand and respond appropriately. Price signals should be reasonably stable so that customers responding to them can invest in facilities and equipment, adjust consumption practices, and select a rate schedule on which to take service, all with a reasonable expectation that their decisions will be rewarded rather than penalized. In some cases, large and frequent rate fluctuations may do more to frustrate customers than to encourage them to consume electricity more efficiently. Such a result would frustrate our goals of customer understandability and acceptance.

Another reason for approaching marginal cost ratemaking with care is the fact that measuring marginal costs of electric utilities is an art and science which is still evolving. We observed in Edison's last GRC that "[o]ur use and calculation of marginal costs over the past six years has been an evolutionary process."[6] While considerable progress in both the calculation and use of marginal costs has been achieved, we recognize that further progress can and should be made. For example, as we note later in this decision, our ability to use marginal costs for revenue allocation on a schedule-by-schedule basis remains limited because load research data and similar information is not always available.

Several witnesses in the Phase 2 hearings acknowledged the variability if not volatility of marginal cost measurements. Edison's witness Cuillier stated that:

> "This volatility in the marginal cost areas....provides a greater justification for attempting to limit changes to revenue allocation to a fairly narrow band in order to eliminate the possible widely fluctuating allocations from one proceeding to the next."[7]

Although CAL-SLA would emphasize marginal cost-based ratemaking over rate stability, its witness, Mr. Schmidt, testified that:

> "[Marginal costs] are not stable. Part of it is due to the methodology which continues to be refined, and then also the escalation of those costs over time."[8]

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6 Id., 487.

7 Tr. 6068.

8 Tr. 6004.

> "Yes, I will emphasize the cost to provide the service over the rate stability goal. Obviously there is a balance."[9]

The Phase 1 decision in this GRC demonstrates another way that marginal cost measurements can vary. In discussing the adopted method for calculations, we observed the sensitivity of marginal costs to changes in the discount rate and inflation rate chosen for the present value calculation. For example, a 1% change in either rate can change marginal generation costs by about 5%, and marginal transmission and distribution (T&D) costs by 10% or more.[10]

In this proceeding, Edison has emphasized the principle of rate stability to a much greater degree than the other parties. Relying on information from Edison's Customer Service Department, Edison's Rate Design Supervisor, Mr. Goeddel, testified that Edison's customers have a strong preference for stability and predictability in rates.[11] Other goals that Edison repeatedly emphasized and relied upon in developing its proposals include customer understandability and acceptance.

We are in general agreement with Edison that marginal cost-based ratemaking must be balanced with other ratemaking goals, but parties would be mistaken if they were to read into this agreement a retreat on our part from the principles we have pursued in the past decade. Indeed, as IU correctly points out, one aspect of rate stability is stability in the regulatory principles we follow in setting rates. A retreat from now firmly established principles would be both misguided from a policy standpoint and

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9 Tr. 6005.

10 D.91-12-076, p. 129.

11 Tr. 5802.

would certainly be destabilizing; and we do generally give less weight to rate stability concerns than Edison does in this proceeding. We are simply concerned that overreliance on marginal cost ratemaking without consideration of factors such as stability will not be in the long-term interests of Edison's customers.

4. Revenue Requirement and Present Rate Revenues

4.1 Adopted Revenue Requirement

Edison's authorized revenue requirement for 1992 was determined by D.92-01-018 in its recent ECAC proceeding. That decision adopted revenue changes associated with Edison's ECAC and other balancing accounts. It also consolidated and implemented revenue requirement adjustments adopted in several other proceedings, including Edison's 1992 cost of capital proceeding and Phase 1 of this GRC. The revenue requirement authorized for 1992 was $7,479.16 million. We adopt that amount for purposes of revenue allocation and rate design. This decision does not change Edison's authorized revenue requirement.

Edison proposes that the rates which become effective June 7, 1992 be designed to collect $7,479.16 million, but it also seeks in Phase 2 an additional increase in its authorized revenue requirement for 1992. Edison states that adoption of its rate design proposals will require the purchase and installation of additional higher-cost meters. For example, Edison hopes to attract residential customers to Schedule TOU-D through revisions to the structure of that schedule. Edison forecasts a net revenue requirement increase per customer of $89.87 and a shift of 4,950 customers from Schedule D to Schedule TOU-D on an annualized basis in 1992.

Edison requests that its Authorized Level of Base-Rate Revenue (ALBRR) under the Electric Revenue Adjustment Mechanism be adjusted by $970,257 effective for service rendered on and after June 7, 1992. Under this proposal, the ALBRR increase would be effective June 7, but customer rates would not be changed until Edison's 1993 ECAC proceeding. For 1993 and 1994, Edison requests recovery of additional revenue requirement of $1,030,783 and $810,601 respectively in its operational attrition filings. No party opposes these requests.

Edison's authorized GRC revenue requirement was considered and adopted in Phase 1, consistent with both the RCP and the ALJ Ruling dated February 1, 1991.[12] The RCP makes no provision for considering revenue requirements in Phase 2. It provides that, on Day 0, the utility shall file its GRC application which shall include its final exhibits except for rate design. The February 1, 1991 ruling did modify the generic RCP schedule for purposes of this proceeding, but the only transfer of subject matter between phases authorized therein was a shift of marginal cost revenue responsibility (MCRR) and revenue allocation from Phase 1 to Phase 2.

Edison does not explain why it has requested consideration of this meter-related revenue increase in Phase 2, and we can only speculate on what the reasons might be. If it is because a more precise forecast of the meter-related revenue requirement is available at a later date, the rationale falls short of justification for departure from the RCP. It will almost always be true that a forecast based on more up-to-date data will be more accurate and reliable than a comparable forecast which is based on older information. From a practical, procedural standpoint, we can never have perfectly current forecast data; that is a basic fact that always confronts utilities and the Commission with future test-year ratemaking.

If the reason for Edison's delayed request is that the subject matter--meters associated with Edison's rate design

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12 See Footnotes 1 and 2, supra.

proposal--is addressed in Phase 2, again the rationale falls short. Edison's forecast is based on the assumption that its rate design proposals will be adopted. To the extent that our adopted rate design differs from Edison's proposals, the reliability of Edison's forecasts is diminished accordingly. Any incremental increase in the reliability of the forecast which results from consideration in Phase 2 is thus likely to be offset in any event.

Phase 1 was the forum where all parties with an interest in revenue requirement issues were expected to focus that interest. We see no reason why Edison could not have, and should not have, addressed this issue in that phase. Edison submitted its intial Phase 2 rate proposal on March 7, 1991, then updated this proposal with testimony served in July 1991 and again in February 1992. On each occasion, Edison requested the supplemental revenue requirement authorization for these meters. The amounts requested for 1992 were $959,523, $979,160, and $970,527 respectively. The first two forecasts were put forth by Edison at times when they could have been litigated in Phase 1, since Phase 1 technical update hearings were concluded September 23, 1991.[13]

We also note that in September and October 1991, Edison provided notice to the public and to its customers that the Commission had reviewed Edison's expenses and investments to determine needed total revenue changes in Phase 1, and that in Phase 2 the Commission would reallocate rates among customer classes. (Reference items I, J, and K.) These notices did not inform customers that revenue changes would also be considered in Phase 2. In view of the notification provided by Edison, it would be grossly unfair for the Commission to proceed with consideration of revenue changes in Phase 2.

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13 D.91-12-076, p. 5.

In comments on the proposed decision, Edison asserts that it "appeared clear" from the RCP that "Phase 1 was to be litigated assuming rate design effective January, 1991." Edison relies on Appendix B, page B 21, paragraph 3 of the RCP as support. We disagree. The subject of the reference is present rate revenues, not test year and attrition year revenue requirements. Edison also claims that the Commission would have prejudged the results of rate design litigation by deciding this issue in Phase 1. We appreciate Edison's concern but do not see it as a reason for after-the-fact approval of Edison's decision to depart from the RCP. Any contingencies needed to avoid prejudgment could have been addressed in Phase 1.

In its comments on the proposed decision, DRA requests that the decision make it clear that any denial of the increased revenue requirement should not lead to any decrease in the implementation of optional time-of-use rates. We find such clarification to be unnecessary, since we fully expect Edison to proceed with implementation of such rates as it has represented in this proceeding.

We find no justification for Edison's decision to depart from the RCP, and will dismiss its supplemental revenue requirement request.

4.2 Sales

In the Phase 1 decision we adopted forecasts of customers, sales, and present rate revenues for Phase 1 purposes. We also noted that both Edison and DRA argued in Phase 1 that the more current sales forecasts filed in A.91-05-050, Edison's recent ECAC proceeding, should be used for revenue allocation and rate design in Phase 2. CFBF disagreed at the time and argued that Edison's adopted GRC forecast should be applied in the ECAC proceeding as well as in Phase 2. We then relied on the Phase 1 record to determine the GRC revenue requirement in Phase 1 with an understanding that parties would be allowed to revisit the question of which forecast to use for revenue allocation and rate design in Phase 2.[14]

CFBF initially reiterated its position in its Phase 2 testimony, then withdrew this testimony during the hearings. CFBF no longer contests the use of the ECAC sales forecast, including the forecast of 2,211.5 gigawatt hours for the Ag & Pumping group adopted in D.92-01-018. There is no remaining controversy. The ECAC forecast will be used for Phase 2 purposes.

4.3 Adopted Present Rate Revenues

The forecast of present rate revenues by rate group and rate schedule which we adopt for Phase 2 purposes is based on revenue requirement, sales, and billing determinants adopted in D.92-01-018, and is set forth in Appendix A.

5. Marginal Unit Costs

5.1 Components of Marginal Costs

The three principal components of an electric utility's marginal cost are (1) the cost of providing energy, (2) the cost of meeting a customer's demand, and (3) the cost of providing customers with access to the utility system. The first of these components, marginal energy cost, is the change in a utility's total operating costs which results from producing an additional kWh of electricity. Marginal energy costs vary over time and are therefore calculated on a time-differentiated basis by both time of day and by season.

The second component, marginal demand or capacity costs, measures the change in total costs caused by a kW change in demand. Marginal demand costs are calculated in terms of the incremental investment in physical plant needed to serve the next unit of load

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14 Parties were allowed this option by an ALJ Ruling dated October 7, 1991.

and are subdivided into three categories: generation, transmission, and distribution.

The third component, marginal customer costs, are the costs of providing access to the utility system to an additional customer and the costs of maintaining existing customers on the system. Marginal customer costs are not intended to reflect either energy consumption or capacity demand.

5.2 Adopted Marginal Costs

For this GRC, most marginal cost methodology issues were decided in Phase 1. D.91-12-076 adopted the uncontested joint testimony submitted by several parties as Exhibit 113. Marginal costs which result from application of Exhibit 113, the operating expenses adopted in Phase 1, and the average gas price of $2.83 per million British thermal unit (MMBtu) adopted in D.92-01-018 are adopted for Phase 2 purposes.

The Phase 1 decision also adopted the uncontested joint testimony of Edison, DRA, and CAL-SLA on marginal streetlight costs (Exhibit 117). Exhibit 117 contains an agreed-upon method to calculate marginal streetlight costs, to be updated for adopted plant loading, working capital, and operational and maintenance (O&M) costs. The marginal streetlight costs based on this method are adopted for Phase 2 purposes.

5.3 Remaining Marginal Cost Issues

5.3.1 Finality of Phase 1 Marginal Cost Determinations

During the Phase 2 hearings some parties offered testimony on marginal cost calculations, resulting in several motions to strike on the basis that marginal unit costs were addressed in Phase 1.[15] We affirm the ALJ's Rulings which struck certain marginal cost testimony from the Phase 2 record. As we made clear in D.91-12-076, Phase 1 was the forum for marginal cost issues in this GRC.

We note that disputes and misunderstandings over marginal costs and attempts to further address them in Phase 2 may be, in part, a by-product of the RCP as modified for this proceeding. We are sympathetic to the concern of ACWA, raised in argument on the motion to dismiss its marginal cost testimony, that bifurcation of marginal costs and revenue allocation determinations insulates any possible feedback loop.[16] The details of this bifurcated approach may deserve further consideration in the early stages of future GRCs or in the RCP rulemaking proceeding, but in any event it is not our intent to litigate the same issues twice in each GRC.

5.3.2 Further Study of Marginal Costs

AECA believes that additional data is necessary to more accurately determine customer-class marginal costs, and recommends that Edison develop this data as a way to improve class-specific revenue allocations in Edison's next GRC. AECA believes that each utility has a responsibility to develop the best possible class-specific marginal cost methodology. CFBF supports AECA's recommendation, while Edison and FEA oppose it.

AECA is concerned that as urbanization of rural areas in Edison's service territory takes place, the agricultural sector is being charged for investments needed to provide service to other customer classes. AECA states that PG&E has recently taken steps

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15 Edison filed a motion to strike testimony of portions of the testimony of AECA and ACWA. IU filed a motion to strike portions of DRA's testimony. IU made an oral motion to strike Edison's testimony on gas prices to be used in marginal cost calculations.

16 Tr. 5783.

to improve its class-specific allocations through participation in a 1990 study of agricultural rates and an "Area Cost Study" which PG&E has submitted with its current GRC (A.91-11-036). AECA suggests PG&E's studies as models for an Edison study which would include differentiation of the costs of serving rural versus urban areas and a reflection of differing qualities of service among customer classes.

AECA recommends that Edison complete the studies in time for review by parties prior to the commencement of Edison's next GRC. AECA did not submit a study proposal in the hearings but did set forth in its opening brief parameters and procedures of such a study. AECA recommends the Commission order Edison to perform the study if Edison does not volunteer (in its reply brief) to do so.

Citing previous studies such as the California Public Utilities Commission Staff Report Regarding Assembly Bill No. 4217 (Bronzan) (Assembly Bill (AB) 4217 study), Edison believes that further study of area cost differences in its service territory is unnecessary. Edison asserts that its methodology for measuring marginal T&D costs does not result in agricultural customers being charged for urbanization-related costs because marginal T&D costs are calculated with a regression analysis which relates growth in T&D investments to growth in T&D demand.

Edison suggests that if anything, agricultural class revenue responsibility may be understated. Based on data from the AB 4217 study, Edison's witness Silsbee testified that increases of 2% to 4% in the revenue responsibility for rural areas could result. However, Edison does not believe that the incremental precision in revenue responsibility justifies developing such class-specific distribution marginal cost estimates, due to the difficulty of doing so.

We adopted as reasonable a methodology for calculating marginal unit costs in Phase 1, and in this decision we find that MCRR calculations using the Phase 1 marginal costs are reasonable.

Nevertheless, we generally agree that for the future, obtaining more precise marginal cost data which would, among other things, support more precise class-specific revenue allocations on the basis of marginal costs is a worthy goal. We have already noted the fact that measurement of marginal costs is an evolving process, and we expect Edison to continue to strive toward the goal of improving these measurements. We are not prepared to accept the proposition that the AB 4217 study demonstrates that further efforts to improve class-specific allocations will remain unnecessary; nor do we believe that necessity is the only criterion for determining whether further study is appropriate.

Still, we are not persuaded that an order requiring Edison to replicate the PG&E area study or to otherwise segregate class-specific marginal T&D costs is the best means of furthering the goal of improved marginal costs for the Edison system. We hesitate to require a utility to conduct a study which may be both complex and costly without greater assurance that it would produce more than an incremental improvement in the precision of class-specific allocations.

We are also reluctant to require Edison to conduct studies modeled after those which have been presented but not yet litigated and decided in PG&E's GRC. Finding in this decision that PG&E's area study approach is an appropriate model for Edison would require that we prejudge its validity and use in the PG&E GRC. And even if we do ultimately adopt PG&E's area study, it does not necessarily follow that it will be an appropriate model for Edison, due to differences in the two utilities and their customers.

Accordingly, we will not require Edison to conduct the studies requested by AECA. Similarly, we will not order Edison to complete a study of the differences of above-ground and underground facilities as requested by ACWA. Given the record before us in this proceeding, we cannot find that the studies would be cost-effective. The fact is that at this time, Edison is in the best position to assess the costs and benefits of performing such studies. We urge and expect Edison to make such assessments and to proceed with all cost-effective marginal cost methodology refinements in time for its next GRC. In particular, we expect Edison to carefully monitor the outcome of the PG&E GRC with respect to marginal cost determinations, and to act on any general principles adopted in that PG&E case that are relevant to Edison's own marginal cost measurements.

5.3.3 Energy Reliability Index

The energy reliability index (ERI) is a measure of the value of generation capacity in calculations of marginal costs. When a utility needs capacity to increase reliability of service, its ERI is 1.0, and marginal costs include all marginal generation costs. As capacity is added and reserve margin increases, the value of incremental capacity declines, and the ERI drops below 1.0. Marginal generation costs are discounted by the reduced values of the ERI.

In the Phase 1 decision we adopted a six-year average ERI of 0.63 which was based on the California Energy Commission's 1990 Electricity Report (ER90) "barebones" resource plan. In doing so we indicated that other ERI calculations may be required in the future. We did not conclude that a six-year average is appropriate in every circumstance. We also adopted DRA's "fully built" resource plan, but reserved judgment on the propriety of its use for rate design or any other purpose. While the selection and use of an ERI adjustment is largely a marginal cost issue, we address its application to revenue allocation and rate design in the following sections.

6. Revenue Allocation

6.1 Introduction

The Commission's fundamental revenue allocation policy is that total revenue responsibility should be allocated to ratepayers on the basis of their share of the utility's marginal cost.

Reliance on marginal cost principles achieves equity in rates and imparts information to customers by relating the costs imposed on the utility system to the customer responsible for those costs. We apply marginal cost principles by first defining groups of customers for which there is sufficient data about their consumption of electricity (generally, load research data). We then apply unit marginal costs and load research data to determine each group's MCRR.

Because the total MCRR is unlikely to equal the utility's embedded cost revenue requirement, it is necessary to adjust the MCRR allocation to allow the utility to collect the authorized revenue requirement. We have adopted the Equal Percent of Marginal Cost (EPMC) method to make this adjustment. This method allocates the revenue requirement on an equal basis relative to the marginal cost-based burden each customer class imposes on the system.

In Edison's last GRC we adopted a full EPMC approach for allocating Edison's revenue requirement, to be implemented in a way designed to mitigate the effects of large rate increases.[17] We pointed out that we had already endorsed the EPMC approach to revenue allocation in an earlier decision, where we had "cited the following reasons as support for 'embracing EPMC as a guiding principle for revenue allocation' [citation]: (1) EPMC provides a fair way of relating each class' revenue requirement to the costs of providing service to that class; (2) EPMC helps reduce inter-class subsidies that distort price signals and thus result in inefficiencies to the detriment of society in general; and (3) EPMC is effective in bringing rates closer to marginal costs in precisely those customer classes most likely to bypass the utility

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17 26 CPUC 2d 392, 612; Conclusions of Law 129 and 130 (1987).

system."[18] We adopted a 100% EPMC allocation in Edison's 1991 ECAC proceeding.[19]

With one exception, use of the EPMC method for setting revenue allocation targets was not contested in this GRC. ACWA, the only party which did not endorse an EPMC-based allocation in Edison's last GRC, argues that basing revenue allocation and rate design on the EPMC approach "obliterates" marginal cost pricing signals and that other economically efficient approaches are available.

ACWA did not present a revenue allocation proposal incorporating its preferred approach, and we have no basis to consider any approach but EPMC for this proceeding. ACWA's only recommendation is that Edison be ordered to conduct a rigorous demand elasticity analysis and present a revenue allocation based on inverse elasticity principles in its next GRC. We will not adopt this recommendation. The record in this proceeding does not demonstrate that the EPMC approach distorts marginal cost price signals. Even if that were the case, we are not persuaded that the drastic step of abandoning EPMC pricing and moving to demand-based pricing would be justified.[20] Moreover, as we indicated in our rejection of the AECA and ACWA requests for marginal cost studies, we are reluctant to order studies of this nature in the absence of evidence that they will be cost-beneficial.

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18 Id., 524.

19 38 CPUC 2d 452, 483; Ordering Paragraph 6 (1990).

20 We harbor no illusions that adopting this approach to utility pricing would be a simple matter. As pointed out by DRA witness Price, inverse elasticity pricing, also known as "Ramsey" pricing, is difficult to administer and its results are often seen as inequitable.

Our adopted revenue allocation, which incorporates the adopted treatment of revenue allocation issues discussed in this section, is set forth as Appendix B.

6.2 Selection of Groups for Revenue Allocation

Edison's five major customer groups are Domestic, LSMP, LP, Ag & Pumping, and SL. In Edison's last GRC we subdivided the LSMP group into rate groups GS-1 and GS-2 and the LP group into TOU-8-SEC, TOU-8-PRI, and TOU-8-SUB for a total of eight rate groups for revenue allocation purposes. We also directed Edison to collect the data to develop the marginal costs necessary to achieve an EPMC intra-class revenue allocation for the LSMP and Ag & Pumping schedules for this GRC.[21] In response, Edison has proposed a further disaggregation for a total of 13 rate groups: Domestic, GS-1, TC-1, GS-2, TOU-GS, TOU-8-SEC, TOU-8-PRI, TOU-8-SUB, PA-1, PA-2, TOU-ALMP-2, AG-TOU, and SL.

CFBF supports Edison's proposal for the Ag & Pumping group. DRA concurs with Edison's proposed disaggregation but recommends two refinements. First, DRA proposes a separate EPMC allocation for Schedule TOU-PA-5. The second refinement is a proposed suballocation of allocated revenues to super-off-peak (SOP) rate options within the large commercial and industrial (TOU-8) rate groups. We address this latter proposal, and CLECA's proposal for a further division within the TOU-8 groups, in our section on LP rate design.

Schedule TOU-PA-5 schedule is an agricultural rate schedule which, according to DRA, serves higher load-factor customers than other agricultural schedules (3,800 annual hours versus 2,700 hours for the remainder of the AG-TOU schedules). DRA

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21 26 CPUC 2d 392, 615; Ordering Paragraph 42 (1987).

estimates show that a lower percentage of the TOU-PA-5 customer annual energy use is in the summer on-peak period than that of the other AG-TOU customers (24% versus 38%), and the marginal cost of service is lower (5.53 ¢ per kWh versus 6.55 ¢ per kWh). DRA believes that when customers on an identifiable rate option like Schedule TOU-PA-5 have a lower cost of service, the schedule should receive a separate allocation both for reasons of equity and for availability of a cost-based option for other customers.

Edison and CFBF oppose DRA's recommendation for the TOU-PA-5 schedule. The dispute centers on the reliability of available load research data and statistical techniques used to apply this data to the TOU-PA-5 allocation. Edison believes that sufficient, statistically valid load characteristic measures are not yet available. CFBF argues that it would be a disservice to make allocations based on speculation.

Edison criticizes DRA's use of recorded billing data for AG-TOU customers to estimate coincident demand based on a regression analysis of coincident demand and on-peak energy usage for all sampled Ag & Pumping customers. Edison is concerned that estimating load characteristics through statistical methods as proposed by DRA rather than using detailed load research data could lead to the creation of a large number of rate groups and instability in revenue allocation and rate design. Edison points out that even with its proposed allocation for the AG-TOU rate group, the TOU-PA-5 customers will be moved toward their cost of service in this proceeding.

We believe Edison's concern is generally a legitimate one but is overstated in this instance. We do not expect a proliferation of suballocated rate groups and resulting instability in future proceedings as a result of adopting DRA's single proposal for this schedule. We expect that detailed load research data will continue to be the best approach to making MCRR determinations and will be increasingly available over time, but in this case DRA has demonstrated that its regression analysis to measure coincident demand is statistically valid and well within Edison's own standard for statistical validity. Numerous regression approaches used by DRA all had the generally consistent results in establishing on-peak energy use as a strong predictor of coincident demand. Also, as shown by DRA, Edison does not rely exclusively on load research data for its own MCRR proposals.

Edison suggests that a preliminary analysis it conducted indicates that summer on-peak usage by the TOU-PA-5 group may exceed that of the AG-TOU group on a percentage basis. We must give little weight to this assertion since it was no more than preliminary, was not offered by Edison until cross-examination in the rebuttal hearings, and was offered without further foundation.

We conclude that DRA has established that TOU-PA-5 has different characteristics than the other AG-TOU schedules and has established a valid basis for a separate allocation. We do not believe that adoption of DRA's proposal is a matter of speculation, as CFBF argues it is. For the foregoing reasons, we adopt Edison's uncontested proposal for disaggregation of customers along with the allocation to the TOU-PA-5 group as proposed by DRA.

6.3 Marginal Cost Revenue Responsibility Calculations

6.3.1 ERI Adjustment

In Edison's last GRC the Commission ordered Edison and the Public Staff Division (DRA's predecessor) to present testimony in this GRC on the applicability of the ERI to marginal generation cost calculations and to determinations of demand charges in rate design.[22] As part of its response to this directive, Edison included with its MCRR recommendations an analysis of the use of ERI adjustments for calculating MCRR. Edison points out that the

22 Id., Ordering Paragraph 37.

product of the long-run marginal generation cost and the ERI is a measure of short-run marginal cost, and that the choice between using long-run and short-run costs for MCRR calculations is judgmental.

Edison prefers the use of long-run costs for revenue allocation purposes for stability reasons and therefore does not recommend an ERI adjustment. Edison points out that customers may form expectations regarding future prices partly on the basis of present prices. Edison believes that volatility in the EPMC-based revenue allocation which would result from using short-run costs could send price signals which would in turn lead consumers to make less economically efficient durable investments.

DRA points out that Edison has recommended an ERI adjustment for calculating interruptible credits (as DRA has done). DRA believes that revenue allocation and rate design should be based on the same approach, a contention which was echoed by other parties and which we address in our discussion of interruptable credits.

DRA acknowledges the necessity of long-run considerations such as stable pricing signals and avoidance of dramatic revenue swings, but argues that short-term price signals are equally important. DRA maintains that its recommended ERI adjustment provides a necessary balance between short-run and long-run considerations because it is based on a six-year average ERI.[23] DRA believes that six years is long enough to provide stability and

23 DRA's six-year average ERI recommendation reflects the "barebones" resource plan for Edison and was computed using Edison's August 28, 1991 compliance filing in the Biennial Resource Plan Update proceeding (BRPU) (Investigation 89-07-004). DRA revised its calculation in its February 1992 update exhibit to reflect the floor ERI of 0.1 which was adopted in D.91-11-057.

reasonably long-term pricing signals yet short enough to give some weight to short-term capacity surpluses.

We faced a similar choice in PG&E's last GRC (A.88-12-005). In adopting the use of a six-year average ERI for computing PG&E's marginal generation capacity cost, we stated that "taking the very long view and ignoring forseeable surpluses in capacity would result in ratepayers paying more for peak capacity than is justified by the system's circumstances."[24]

We believe that a similar approach for recognizing the existence of short-term capacity is warranted in this case. While we wish to avoid or temper volatility in revenue allocation, we agree with DRA that its use of a six-year average ERI calculation results in a reasonable balance of long-term and short-term marginal cost measurements. We are not persuaded that this adjustment is likely to result in dramatic or inappropriate revenue allocation swings, nor do we believe that the value of the price signals that are sent through the revenue allocation process will be greatly diminished. In a regime of cost-based ratemaking, it is appropriate to give some weight to the fact that Edison's generation capacity situation can be expected to change over time. When there is excess capacity, higher cost resources are less likely to be utilized, and it is reasonable to reflect that fact in the way that revenue responsibility is allocated among customers.

CMA agrees with Edison that there should be no ERI adjustment for revenue allocation calculations, but raises another argument. CMA contends that the ERI adjustment to revenue allocation causes classes with greater peak demands in relation to annual use to pay less for on-peak demands than do higher load-factor customers. CMA believes that the existence of excess

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24 34 CPUC 2d 199, 317 (1989).

generation capacity does not justify this distortion. CMA does not cite evidence supporting this argument; we note that other parties did not have an opportunity to respond to it because it was presented in a reply brief. We reject CMA's argument for the foregoing reason and because we find no other support for it. When we apply an ERI of less than 1.0, we are saying in effect that the marginal generation capacity cost is less that the full marginal cost of a combustion turbine which is used as a proxy for marginal generation cost.[25] We find no basis for asserting that the product of this adjustment, which represents our best estimate of the marginal generation cost, results in a distortion of revenue responsibility among customers with different load factors.

No party has disputed DRA's updated calculation of the six-year average ERI, which reflects our recently adopted floor of 0.1 for the ERI. We will adopt DRA's recommendation, and apply an ERI of 0.78 for calculating Edison's MCRR.

6.3.2 The Reserve Margin Issue

Generating facilities are not perfectly reliable, and it is necessary for a utility to maintain a reserve margin by installing more than one kW of capacity to serve a kW of demand. Edison adjusted its marginal generating cost with a Capacity Response Ratio (CRR) of 1.15 to reflect this fact in MCRR calculations. With the exception of TURN, all parties who addressed this issue support Edison's adjustment. They also reject an alternative proposal of TURN.

TURN believes that such an adjustment is correct, but argues that a better analysis would allocate to each class its individual responsibility for the reserve margin. TURN states that higher load factors are generally beneficial to the utility system and that customer classes with high-load factors are properly

25 Exhibit 113, p. 1 and Table 3.

allocated less revenue responsibility than those with lower load factors. However, TURN also believes that the reserve margin is an exception to this rule. A utility's reserve requirements are dependent on its load shape. Assuming the same utility resources and the same peak load, a lower load factor and a more peaked load means there are fewer hours close to the peak. A utility with a more peaked load shape can get by with a lower reserve margin for two reasons. First, it has more time for maintenance. Second, with fewer hours close to the peak, a generation emergency which causes loss of load will be less probable and less severe (i.e. loss-of-load probability (LOLP) is lower).

TURN believes that this phenomenon should be reflected in revenue allocation on a class-specific basis. To do so, it decomposed Edison's reserve margin into a different percentage for each class. Using reliability modeling to analyze the effects of class load shapes, TURN concluded that the classes with higher load factors caused a greater need for reserves. TURN calculated hypothetical class-specific reserve margins which ranged from 10% for domestic customers to 30% for time-of-use customers at transmission voltage.

TURN used the resulting class-specific CRRs for its revenue allocation proposal. The result is an allocation of approximately $30 million less to the domestic class, small decreases to LSMP and SL, and increases to other classes.

Edison, CLECA, and FEA presented rebuttal testimony in opposition to TURN's proposal. The essence of this testimony is summarized below:

1. Edison's Probability of Loss of Load (POLL) model takes maintenance into account. Thus, the maintenance effect described by TURN is already captured in the LOLPs used to calculate MCRR. TURN's proposal results in a double adjustment;

2. It is not correct in Edison's case that higher load factors require more reserve

margin. Because of Edison's relatively low-load factor of 52% there is sufficient capacity to allow an increased system load factor before additional capacity is needed;

3. The methodology used by TURN is flawed because it departs from marginal analysis and it relies on an incorrect assumption. As part of its analysis TURN scaled-up class load shapes to match the peak load of the system. In doing so it both nullified the marginal nature of the analysis and assumed that Edison would have planned and built its current resource mix to serve a total load having the shape of each of its classes. In fact, utilities create capacity to meet the diversified load of a system. Reserve margins are planned on a system basis rather than a class-specific basis;

4. If it is appropriate to isolate class-specific costs for the purpose of assigning reserve margin capacity, it is appropriate to isolate all costs of serving a class. If Edison were to serve each class on a stand-alone basis, its generation mix would be different than it is now. Customers with low-load factors would require more expensive peaking capacity than those with higher load factors. Class-specific marginal generation costs, energy costs, and ERIs should therefore be considered if class-specific CRRs are used. TURN has not accounted for all class-specific cost differences; and

5. The proposal sends conflicting price signals. Edison has various programs and rates which encourage customers to reduce power use on-peak and increase use off-peak, thereby increasing their load factors. TURN's proposal would result in increased revenue allocation to those customers as a consequence of their shifts.

We dispose of the last argument first. The point of TURN's proposed adjustment is that while flatter loads generally lead to lower costs, there is one effect of flatter loads that moves costs upward somewhat. TURN has attempted to prove the existence of and then measure this effect. To the extent that the resulting marginal cost measurement is a correct one, it would be reasonable to reflect it in rates. We find no "price signal conflict" in allocating revenue on the basis of marginal cost.

However, we find the other arguments against TURN's proposed class-specific reserve margins to be persuasive. While we commend TURN's effort to achieve greater precision in marginal cost ratemaking, we will not adopt its proposal. First, even accepting the premise that a utility with a more peaked load shape has fewer hours close to the peak and therefore can tolerate a lower reserve margin than a utility with a flatter load, the same does not necessarily hold true for individual classes served by a diversified utility. Second, TURN's scaling up of each class' load shape to the system level requires it to assume that the entire system serves only that class' load. This yields a hypothetical construct which is undermined by the fact that Edison's resource mix was designed for the diversified system load imposed by all customers. Third, Edison has shown that TURN's proposal would result in a double adjustment for the maintenance effect described by TURN. Thus, even if it is true that different classes impose varying degrees of responsibility for reserve requirements, we cannot rely on TURN's measurements.

We believe that the use of a single CRR of 1.15 as proposed by Edison results in a reasonable allocation of generation cost among customer classes.

6.3.3 Coincident and Noncoincident T&D Costs

In its MCRR calculations, Edison attributes transmission marginal costs to each rate group based on 100% coincident demand and distribution marginal costs based on 100% noncoincident demand. DRA proposes that transmission and primary distribution costs be allocated using a combination of coincident demand, based on LOLP and noncoincident demand. CLECA supports DRA's recommendation.

DRA states that the loading on Edison's transmission system is more diverse than on the generation system and that loading on the primary distribution system is more affected by simultaneous demands than that which occurs at the customers' points of connection to the distribution system. The T&D systems must be sized to meet loads greater than coincident demand but less than noncoincident demand. DRA's recommended shares are 92.29% coincident and 7.71% noncoincident for transmission costs and 33.19% coincident and 66.81% noncoincident for distribution costs. DRA notes that by comparison, in Edison's last GRC, transmission capacity cost was allocated 93% to coincident demand and 7% to noncoincident demand, and primary distribution cost was allocated 40% to coincident demand and 60% to noncoincident demand.

Edison acknowledges that its T&D system has both coincident and noncoincident demand-related characteristics but recommends adoption of its approach as a simpler one.

With minor calculation revisions, DRA's recommendation is a reasonable step towards greater precision in the use of marginal costs to set electric rates and is consistent with the approach we followed in Edison's last GRC; we will therefore adopt it for revenue allocation and rate design. We do not view it as an undue complication, as suggested by Edison.

6.4 Capped EPMC Revenue Allocation

6.4.1 Allocated and Nonallocated Revenue

Not all of the utility's revenue requirement is "allocated" on the basis of MCRR. For example, the cost of facilities for streetlighting customers are identified and revenues are directly assigned to the SL class on the basis of those costs. Edison proposes to continue this practice. Edison proposes that, in addition to streetlight facilities, nonallocated revenues include those which recover the costs of domestic TOU meters and capacitors which are paid for through the power factor adjustment. Additionally, Edison excluded revenues collected under the Low-Income Rate Assistance (LIRA) program and special contacts which avoid or defer self-generation from the revenue allocation process. Edison does not contest DRA's proposed treatment of the 25% employee discount allowed under Schedule DE. DRA treats the amount of the discount as an operating cost which is paid for by all customers through an adjustment to total residential sales. We adopt this uncontested treatment of nonallocated revenues. One other issue requires discussion. Edison disagrees with DRA's treatment of load management credits as nonallocated revenues.

Edison offers interruptible service options to its LP and Ag & Pumping customers. Interruptible tariffs provide Edison with an added source of capacity in return for which the customers receive a lower rate. The difference between the interruptible rate and the firm rate is the interruptible credit. Edison also has an automatic powershift (APS) program which allows it to cycle on and off the air conditioning load of customers who elect the APS option. The APS program also provides customers with credits in return for the net capacity benefits they provide to the system. The interruptible and APS credits are referred to collectively as load management credits.

Edison points out that if it were to build or purchase new generation capacity, its revenue requirement would increase. Since it would be appropriate to collect that increased revenue requirement through the EPMC revenue allocation procedure, Edison believes that it is equally appropriate to do so for the load management credits. CLECA, FEA, IU, and TURN agree. To implement this principle, Edison adds the "cost" of load management credits to the basic revenue requirement. The resulting total revenue requirement is then allocated to the various customer groups on a capped EPMC basis. Edison states that a similar treatment was adopted in PG&E's last GRC.

DRA agrees with other parties that all customer classes should pay for load management credits through an EPMC-based allocation, but it recommends including the credits in nonallocated revenues. DRA characterizes its difference with Edison as one of mechanics or even semantics, but recommends its approach for simplicity and understandability. DRA claims that its method was the one adopted in PG&E's last GRC.

We agree that it is reasonable to allocate the cost of load management credits to all customers on an EPMC basis, and we find that Edison's methodology is a reasonable means of achieving that objective. After carefully reviewing the extensive argument on this issue we find that DRA's position can be distilled to the contention that its method is simpler. When properly developed, either method yields accurate results and is therefore acceptable. We find no evidence that Edison's method results in any inappropriate misallocation of revenue responsibility or any undue complication. On the contrary, since it is appropriate to consider load management programs as equivalent to resources which would increase allocated revenue requirements, it is reasonable to treat the cost of the credits as equivalent to allocated revenue requirement, as Edison has done. We will therefore adopt Edison's methodology.

<u>6.4.2 Caps</u>

<u>6.4.2.1 Background</u>

In applying EPMC revenue allocation principles, the Commission has found it necessary to balance its goal of achieving marginal cost ratemaking against the potentially negative impact on certain customer groups that can occur with restructuring of revenue responsibilities. The use of caps which limit the amount by which the class average rate can increase is the standard technique for mitigating harsh bill impacts on customers. Caps are typically defined as the total of the system average percentage change (SAPC) plus a given percentage.

Although the Edison system achieved a full EPMC allocation in its 1991 ECAC, the restructured EPMC calculations adopted in this proceeding require that we again consider the need to mitigate bill impacts. This need arises largely because of the revised marginal costs adopted in Phase 1 and the proposed disaggregation of rate groups, including Ag & Pumping customers.

6.4.2.2 Capping Proposals

Edison proposes that, in general, revenue allocation increases should be capped at SAPC plus 5%. Edison proposes two exceptions. First, because domestic customers have experienced a 45% increase in allocated revenue since 1987 compared to a 24% system increase, Edison proposes that the Domestic class be capped at SAPC plus 2.5%. Second, Edison notes the effect of drought and freeze conditions on customers in the Ag & Pumping group and therefore recommends a cap of SAPC plus 3.5% for these customers.

Like Edison, CFBF proposes a cap of SAPC plus 3.5% for the Ag & Pumping group. CFBF notes that in this case the only two rate groups that would be affected by any of the capping proposals are both within the Ag & Pumping group: PA-1 and TOU-ALMP-2. The data which allowed Edison to disaggregate these groups were collected for two years rather than the norm of five years, and while CFBF does not question the marginal costs used by Edison, it does believe that the limits of the information justify a slower phase-in toward EPMC levels. CFBF also notes the financial hardships faced by Ag & Pumping customers due to drought conditions and the severe freeze which occurred in late 1990 and early 1991 provide further justification for moderated increases. While it recommends a cap of SAPC plus 3.5%, CFBF recognizes the Commission policy regarding EPMC. For that reason it does not recommend a lower cap of SAPC plus 2.5% as Edison has applied to the Domestic class.

AECA is another representative of customers in the Ag & Pumping group. While AECA does not propose a specific cap, it recommends that the Commission carefully weigh any increase in excess of the SAPC and urges that the cap for Ag & Pumping be less than SAPC plus 3.5%. AECA emphasizes the drought conditions that have impacted the class. It estimates that Edison's agricultural customers increased their expenditures for electricity by 17% between 1985 and 1990 due to increase usage (i.e. in addition to rate increases). AECA's witness Moss attributes this increased usage largely to the effects of drought.

CLECA, CMA, DRA, FEA, and IU all recognize that it is appropriate to mitigate the effects of a full EPMC allocation through capping. All but FEA recommend a cap of 5% above SAPC. FEA recommends an SAPC plus 7% cap in order to assure that all classes are moved to full EPMC by Edison's next GRC. DRA similarly recommends a goal of full EPMC by the next GRC, but it believes that an SAPC plus 5% cap is sufficient to achieve that goal. In contrast, CAL-SLA recommends no caps in order to achieve a full EPMC allocation in this GRC.

The parties recommending a 5% or 7% cap generally recommend that the adopted cap be a uniform one for all classes; thus they reject the lower caps of SAPC plus 3.5% and 2.5% as recommended by Edison, CFBF, and AECA. For example, DRA believes that with nonuniform caps, there is a possibility that the very class for which a more restrictive cap is recommended is the farthest from its EPMC allocation. DRA views this as inequitable. Similarly, FEA argues that nonuniform caps are discriminatory. IU believes that Edison's rationale for a lower cap for Domestic customers (the 45% increase since 1987) is not valid because that class had been far below its EPMC allocation.

The SAPC component of the adopted cap(s) is at issue as well. Since the revenue requirement is not changed in this Phase 2 decision, the associated SAPC is zero. Some parties believe that we should consider the effects of the system revenue increase and the revenue allocation which we adopted in Edison's last ECAC. For example, CLECA argues as follows:

> "The SAPC under consideration in this Phase is the combined SAPC for the revenue allocations that will be implemented in January and June. Since this SAPC will be implemented through the ECAC in January, no revenue change is anticipated for June. If, in fact, the ECAC revenue allocation results in the actual implementation of a cap of SAPC plus five percent, the revenue allocation for Phase 2 must be limited to SAPC, having already recovered the five percent above SAPC from capped customers through the ECAC. Assuming that the incremental five percent above SAPC were recovered through the ECAC, recovery of SAPC plus five percent in the period beginning June 7 would actually result in a recovery from capped customers for the combined period of SAPC plus ten percent."

DRA and FEA appear to agree with CLECA. DRA points out that the revenue allocation adopted in the January ECAC decision was interim in nature and that the rates adopted in January would never have been in effect during a summer season. DRA acknowledges that both the pre- and post-January 20, 1992 rates have a claim to being "present" rates, but recommends placing greater weight on the former for capping purposes.

Edison disagrees with these so-called "combined cap" proposals. Edison emphasizes the fact that the present rate revenue is that adopted in the ECAC decision and which is currently in effect and will remain so until June 7, 1992.

6.4.2.3 Discussion

We affirm our policy that the use of caps to mitigate rate increases can be appropriate in EPMC revenue allocations. CAL-SLA is the only party to express opposition, and its major concern is to see that the SL class is allocated a 100% EPMC revenue responsibility without any floor. We find no basis in this case for ignoring our policy of using caps where appropriate.

The selection of a cap requires a balancing of competing objectives, and the choice is ultimately one of judgment as to what is the maximum reasonable increase that can be imposed on a customer group. Thus, for example, while achievement of a full EPMC allocation by the next GRC is a reasonable target, we do not consider it an inflexible goal that must be achieved regardless of present or future circumstances. Doing so could require that we suspend judgment on reasonableness in favor of a formulaic approach. Similarly we believe that a cap of SAPC plus 5% annually as proposed by Edison is a reasonable guideline for the Edison system between now and the next GRC. While we adopt it as a guideline, it should not be considered an inviolate rule, either at this time or in annual ECAC proceedings.

The evidence in this case indicates that under any likely revenue allocation scenario, the EPMC increase for Domestic customers will be less than 2.5%. The choice of a cap for the Domestic class from among the proposals before us will not affect the adopted revenue allocation. Accordingly, whether and by how much to cap the EPMC allocation in this proceeding is, in large part, limited to consideration of the impact of EPMC-based rate increases on certain Ag & Pumping customers and the impact of the subsidy cost which results from capping on the customers who pay for the subsidy.

We believe that the increases allocated to the Ag & Pumping class should be mitigated. A full EPMC allocation under our adopted MCRR calculations would result in the PA-1 group receiving an increase of 17.9% and the TOU-ALMP-2 group receiving an increase of 21.1%. We believe such increases should be mitigated at this time due to the financial hardships faced by some customers served under those schedules. In choosing a cap, we note first that a cap of SAPC plus 7% (for each of the next three revenue allocations) exceeds that which is necessary to achieve a full EPMC allocation by the next GRC even assuming Schedule TOU-ALMP-2 is retained. The remaining choices are our target of SAPC plus 5%, which corresponds to the recommendations of DRA and LP customer representatives; the SAPC plus 3.5% cap recommended by Edison and CPBF; or something less, as recommended by AECA.

In our judgment, Edison struck a reasonable balance in its recommendation for the Ag & Pumping class. It allows some progress to be made toward EPMC. The revenue deficiency resulting from this cap is $16.2 million, which does not impose an unreasonable subsidy burden on other customers. While it is less than our preferred cap of SAPC of 5%, we are of the opinion that weather-related conditions faced by Ag & Pumping customers, when combined with the effects of the MCRR restructuring and rate group disaggregation adopted in this decision, constitute strong justification for a lower cap at this time.

We reject the argument that a uniform cap is required, for several reasons. As Edison points out, the argument ignores our past practice. Also, the Legislature has apparently approved nonuniform caps in special circumstances with the enactment of AB 2236 (which we discuss in the next section). In our opinion, the argument that caps should be uniform, because it is inequitable or even discriminatory for different classes to be different distances from EPMC, is tantamount to an argument for no caps at all. A uniform cap serves to move the exercise of capped EPMC revenue allocation toward a mechanistic approach that gives too little weight to the circumstances which gave rise to the need for capping in the first place.

We turn to the proposal of CLECA, DRA, and FEA to consider the Edison rates which were in effect prior to January 20, 1992. Our first consideration in revenue allocation is to determine the full EPMC allocation. We then determine the distance (percentage) that each class must be moved to reach its full EPMC allocation. We then make judgments about the reasonableness of moving each class the full distance at one time, and mitigate that movement so that no more than the maximum reasonable movement is imposed on a class. With this perspective in mind, we agree it is necessary and appropriate to consider our recent actions to revise Edison's revenue requirement and allocation. This case is an exception to the general rule that we allocate Edison's revenue annually, and as we noted in the ECAC decision, the revenue allocation adopted at that time was interim in nature.[26] These circumstances lead us to agree with DRA that greater weight should be given to the pre-January 20 rates as the "present" rates for revenue allocation and capping. While Edison is correct that this so-called combined capping is a departure from standard practice, we find that it is justified by the circumstances of this case, in which two revenue allocations are adopted less than five months apart. We note that by doing so we allow the SL class to achieve a full EPMC allocation.

6.4.2.4 AB 2236

On October 11, 1991 Governor Pete Wilson signed AB 2236.[27] The legislation became effective January 1, 1992. It states in relevant part:

> "The Public Utilities Commission shall not increase, or approve an increase in, rates for electrical services for agricultural and, if applicable, pumping customers by an amount more than the system average rate increase before June 1, 1992."

The limits imposed by this statute require that we adopt a cap of SAPC with no additive for Edison's Ag & Pumping class. We

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26 D.92-01-018, p. 39.

27 1991 Cal. Stat. 862.

did just that in the January ECAC decision.[28] However, it is not so apparent that AB 2236 prevents adoption of any such increases in this proceeding. While most parties assumed that the Commission may not approve such increases on May 20, 1992, the date originally scheduled for Commission consideration of the Phase 2 decision, DRA and TURN believe that it may do so since the rate revisions are scheduled to become effective after June 1.

AB 2236 was intended as a temporary moratorium, and was apparently aimed at the agricultural rates adopted in PG&E's recent ECAC and perhaps Edison's recent ECAC, not this GRC. In comments on a proposed decision in the PG&E ECAC (A.91-04-003), AECA, the legislation's sponsor, stated that "AB 2236 was crafted so as to impact the pending ECAC decisions."[29] In offering Author's Amendments to AB 2236, Assemblyman Jim Costa expressed concern that the Commission intended "to increase PG&E's agricultural rates by 30-50% over the next several years" but he did not mention Edison's rates.[30] When Governor Wilson signed AB 2236, he stated his concern about legislative intrusions on the Commission's authority. The Governor indicated he was signing the bill because it was only binding on the Commission for five months and because he understood that the author agreed that ratemaking issues should be resolved before the Commission.[31]

TURN is correct in stating that the Legislature intended a moratorium on rate increases of five months only. It is

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28 D.92-01-018, p. 46; Finding of Fact 24.

29 Comments to the Proposed Decision of ALJ Pulsifer (December 9, 1991), p. 13.

30 AB 2236 Statement, p. 1, emphasis added.

31 AB 2236 October 11, 1991 Governor's Message to Members of the Assembly.

certainly the case that the Governor intended to return ratemaking discretion to the Commission after the five-month moratorium, and if we do not exercise that discretion in this proceeding our next opportunity to do so under our Rate Case Processing Plan will be in Edison's next ECAC. The revenue allocation adopted in that proceeding will not become effective until 1993. Moreover, to the extent that we are precluded from adopting our preferred revenue allocation at this time, the effects could linger into future years unless we make up for lost time at the next opportunity with accelerated allocations to the Ag & Pumping class.

Still, despite the intent of the Legislature and the Governor, we agree that the language of the statue prohibits the Commission from approving Ag & Pumping rate increases before June 1, 1992 regardless of the effective date of the rates approved. As CFBF urges:

> "[Th]e plain meaning of the statute must be given effect unless it is demonstrated that the natural and customary impact of the statute's language is either 'repugnant to the general purview of the act,' or for some other compelling reason, should be disregarded. [citations omitted] (Duty v. Abex Corp. (1989) 214 Cal.App.3d 742, p. 749.)"

Several parties suggest that by issuing the Phase 2 decision on or after June 1, the Commission could adopt Ag & Pumping rate increases which it finds to be reasonable. CMA encourages the Commission "to schedule its decision in this matter with care to allow it to approve an appropriate and reasonable revenue allocation." DRA notes that there is time between the expiration of AB 2236 and the effective date of the rates adopted by this decision. As previously noted, CFBF recommends adoption of a cap for Ag & Pumping rates of 3.5% above SAPC. CFBF explains that this testimony was based on the assumption that the Commission decision would not occur prior to June 1. AECA notes that AB 2236 applies *if* the earlier procedural schedule were maintained. TURN suggests consideration of the matter at the first Commission meeting in June to avoid any ambiguity in the statute's applicability. There is no opposition to any of these suggestions to reschedule consideration of this decision. Since this decision will occur after June 1, 1992, the moratorium imposed by AB 2236 is no longer in effect.

6.4.3 Floors

Edison proposes that EPMC-based decreases for any class be made subject to a floor of 5% below SAPC. Edison proposes a floor in order to avoid large changes in annual customer bills and to prevent the possibility of widely fluctuating allocations from one proceeding to the next. Edison believes that application of a floor in this proceeding will reduce the likelihood that a large increase will be required in the future for any floored group. Edison further believes that floors are equitable because customers protected from increases by caps should be limited in the decreases they receive.

Edison is the only proponent of a floor. CAL-SLA, CLECA, CMA, DRA, and IU vigorously oppose any floor in this proceeding, arguing that a floor produces an inequitable allocation of revenue deficiencies (subsidies) that result from capping. They point out that without a floor, the subsidy can be borne equally by all rate groups which are not capped.

DRA believes that a floor might be justified in order to prevent a distorted allocation in cases where the revenue deficiency from capping is large, but believes such a rationale is inapplicable in this case. DRA estimates the impact of its preferred cap is a deficiency of only 0.2% of the system revenue.

CAL-SLA represents public agency customers which take service under TC-1 (traffic control) and SL schedules. CAL-SLA strongly opposes flooring because these schedules are the furthest from EPMC, and customers on those schedules will bear a disproportionate share of the subsidy.

Several parties point out that we recently declined to adopt a floor in Edison's ECAC because customers who are entitled to decreases under EPMC allocations should receive those decreases in the absence of a compelling reason to the contrary.[32] We find no compelling reasons in this case for adopting any floor. For example, we see no reason, let alone a compelling one, to deprive customers on Schedule TC-1 of the cost-based decreases they are entitled to merely because the change is a large one of approximately 27% from the present allocation.

A strong likelihood of large future increases for groups receiving large decreases now might justify a floor, but no such likelihood has been shown to exist at this time. We find Edison's equity argument far short of compelling. There is no evidence that any class which has benefited from caps in the past is one which should be floored now for equity reasons.

There are good reasons for not adopting a floor. We agree that with a floor, classes which are entitled to the largest decreases under EPMC principles pay a disproportionately high portion of any capping subsidy. Allocating the subsidy burden to all classes on an EPMC basis is fairer. Also, as DRA and others point out, a floor will not reduce allocation distortions because the deficiency from capping is small in this case.

Finally, as with caps, the choice of whether to apply a floor (and what level of floor) involves balancing cost-based ratemaking principles and stability. In this case, the customers which would be impacted by floors have expressed a clear preference for an EPMC allocation over rate stability. For this reason and the other reasons discussed above, we will not adopt a floor for this Phase 2 revenue allocation. We should point out, however, that if MCRR relations should change significantly in the future,

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32 D.92-01-018, p. 41.

our decision to not impose a floor may be a relevant consideration in the future selection of caps for those classes which receive decreases due to this decision.

6.4.4 Allocation of Revenue Deficiencies and Surpluses

Edison proposes that the net deficiency or surplus that results from capping and flooring be allocated on an EPMC basis to all groups that are neither capped nor floored. DRA proposes to allocate any net deficiency to all groups which are not capped, including groups which are floored if the deficiency raises their allocation above the floor. Edison and CLECA believe the DRA approach is inequitable because the effect would be that customers entitled to decreases down to a floor of SAPC less 5% would receive a lesser decrease.

The dispute does not require decision for this allocation because we have not adopted a floor. Nor will we decide this issue for guidance in future allocations. We generally agree with Edison and CLECA that once a floor has been selected its impact should not be diminished by any further allocation. However, given our preference for no floors, we cannot envision at this time all of the circumstances that would lead us to make use of floors in the future. It is possible that such circumstances would also lead us to prefer the DRA approach. We view this as a technical issue which should be decided on a case-by-case basis as the need arises. We will adopt the other component of Edison's proposal. The net deficiency that results from capping will be allocated on an EPMC basis to all groups that are not capped.

6.5 Revenue Allocation Between GRCs

Edison proposes that between now and the next GRC: EPMC-based revenue allocations be adopted in annual ECAC proceedings; the method for calculating MCRR adopted by this decision be maintained; the incremental energy rates (IERs) adopted in Phase 1 for revenue allocation remain in effect; the gas price used for developing marginal energy costs be developed using the methodology adopted in Phase 1; marginal demand and marginal customer costs adopted in Phase 1 be used and updated in each annual ECAC proceeding by applying the Gross Domestic Product Implicit Price Deflator; revenue allocations other than those occurring in ECACs be accomplished on an SAPC basis. These uncontested proposals are reasonable and will be adopted. Two other issues require discussion.

First, DRA and IU recommend that parties remain free to propose caps and floors in ECAC proceedings. IU argues against any formulaic approach such as Edison's recommendation to fix a cap of SAPC plus 2.5% in each of the next two ECAC proceedings. We agree with DRA and IU. We are mindful of the large increases that domestic customers have faced in the past few years, but we cannot foresee all of the circumstances that may be relevant to selection of caps (or even floors) in future proceedings. We have already stated our general guidelines of achieving EPMC by the next GRC and setting caps at SAPC plus 5% annually. We will not make further commitments regarding future allocations. We do not believe that this will significantly burden the processing of future ECACs with unnecessary litigation.

The other issue is whether the ERI used to calculate MCRR should be updated between GRCs. DRA proposes that the ERI be updated based on values adopted or presented in future BRPU. Edison proposes that the ERI adopted by this decision remain unchanged until the next GRC for stability in revenue allocation, consistency with use of the same IERs between GRCs, and to reduce litigation over ERIs in ECAC proceedings. Updating the ERI would add precision to revenue allocation in ECACs, but we find the reasons listed by Edison to be more persuasive. We will use the same ERI between GRCs for purposes of revenue allocation.

7. Rate Design

7.1 Introduction

We decide contested rate design issues by first addressing issues which pertain to more than one class of customer, and then examining class-specific issues for each of Edison's five major customer groups (Domestic, LSMP, LP, Ag & Pumping, and SL). Finally, we address issues pertaining to Edison's interruptible rate schedules and mobilehome park customers. In its opening brief, Edison listed numerous uncontested rate design issues. We will make appropriate findings and conclusions without further discussion of these uncontested issues. The adopted rates, which are based on the principles decided in this section, are set forth in Appendix C.

7.2 Common Rate Design Issues

7.2.1 Customer Charges

Edison proposes to change most customer charges by Class Equal Percent Change (CEPC) or CEPC plus 10%. Where full EPMC customer charges would cause only minor customer bill impacts, including the LP schedules, Edison proposes full EPMC customer charges. DRA generally opposes Edison's proposals, advocating greater movement toward EPMC rate levels.

Edison believes that the Commission should not make significant upward movement in customer charges toward their present EPMC levels in this proceeding because of the significant bill increases that would result and because the resulting level of the customer charge may be well above the full EPMC level determined in the 1995 GRC. According to Edison, the full EPMC level for customer costs may change because the definition of marginal customer costs and marginal distribution costs may be subject to significant change in the next GRC. The marginal costs adopted in Phase 1 of this GRC placed 100% of the transformer costs in customer costs instead of distribution costs, even though it was recognized that the final line transformer has both load-related (distribution-related) and customer-related characteristics.

In the Phase 1 decision, we included the question of how to assign line transformer costs to customer or distribution costs among marginal cost issues deferred to Edison's next GRC.[33] The possibility that measurements of marginal customer costs may change significantly may warrant an approach like Edison's for rate stability. Certainly the use of marginal costs to set rates does not require that rates march in lock-step with costs when there are other relevant considerations.

We will adopt the general principle advocated by Edison that it is appropriate to temper marginal customer cost-based increases in customer charges for stability reasons. This does not mean that we necessarily adopt Edison's customer charge proposals, however. Nor do we simply assume as a foregone conclusion that the marginal customer costs which will be adopted in Edison's next GRC will be the same or similar to the marginal customer costs adopted in Phase 1 of this proceeding exclusive of any final line transformer costs. The extent to which this principle should be reflected in rates is addressed in the following sections on class-specific issues.

<u>7.2.2 Nontime-Related Demand Charges</u>

Nontime-related demand charges are based on a customer's highest demand, no matter when it occurs. For non-TOU schedules, Edison proposes to change nontime-related demand charges and connected load charges by CEPC to provide rate stability and to avoid major structural changes which could result in significant customer impacts. For TOU schedules, Edison generally proposes to increase such demand charges by CEPC plus 10% to provide better price signals to these customers.

DRA advocates swifter movement toward EPMC-based charges. Its basic position is that every component of every schedule should

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33 D.91-12-076, p. 129.

reach its full EPMC level as quickly as possible. Consistent with that position, DRA proposes that nontime-related demand charges for LSMP and LP schedules be increased to their full EPMC level in this proceeding. In some cases the increases would be phased in over the three-year GRC cycle.

As with customer charges, and for the same reasons, we generally agree with Edison that rate stability should be accorded significant weight when setting nontime-related demand charges. We will do so in addressing these charges on a class-specific basis. We do not believe it is necessary to adopt a firm goal of achieving a 100% EPMC rate design by the next GRC and will not do so at this time; EPMC rate design still remain as our target, however.

7.2.3 Time-Related Demand Charges

Edison proposes to change time-related demand charges for non-TOU schedules by CEPC to provide rate stability. For TOU schedules, Edison generally recommends that the time-related demand charges be changed by CEPC plus 10% and that time-related demand charges for SOP schedules be changed by CEPC since these charges are already close to full EPMC levels. DRA and the LP intervenors support increases as well.

DRA originally opposed Edison's proposed increases in time-related demand charges, consistent with its proposal for real-time on-peak demand charges. Edison and DRA subsequently reached an agreement on the implementation of a real-time on-peak demand charge on an experimental basis. DRA agreed to a moderate increase in the time-related demand charges on TOU schedules, and agreed that the time-related demand charges proposed by Edison result in moderate increases.

Thus, as IU notes, there is broad-based support for at least moderate increases in time-related demand charges. DRA has raised valid concerns about the appropriateness of using traditional on-peak demand charges for reflecting coincident capacity costs in rates. However, we agree that for purposes of this decision it is appropriate to continue the use of traditional charges. Those charges should be moved closer to marginal costs, as all parties agree. In a subsequent section we address whether Edison's moderate increases or some other level should be adopted for LP customers. (Edison's proposal is uncontested for other classes.) We do note that Edison is correct in pointing out that when its specific charges are applied to schedule proposals which reflect a different revenue requirement than the one it used, the purpose of its recommendation of increases of CEPC plus 10% or 20% is defeated.

Taking a longer-term view of time-related demand charges, we note that DRA has strongly endorsed the expanded use of real-time pricing to more accurately reflect coincident capacity costs. DRA presented an extensive statistical analysis showing that traditional time-related demand charges do not reflect costs as well as was previously assumed. Correlation between on-peak billing demand and coincident demand is spurious, DRA's analysis shows.

Edison finds fault with DRA's statistical analysis, but goes on to dismiss it as moot since DRA has agreed to moderate increases in time-related demand charges and Edison has agreed to implement a real-time on-peak coincident demand charge on an experimental basis. IU agrees with Edison on this point.

We do not dismiss DRA's analysis as lightly as Edison and IU. We find DRA's statistical analysis to be persuasive, and we agree with DRA that expanded use of real-time pricing should be encouraged. We are not prepared to abandon traditional charges now or any time soon, but we do believe DRA has proposed some reasonable actions for expanding real-time pricing options, with traditional on-peak demand charges being an option for customers who choose not to participate in real-time pricing.

DRA is generally satisfied with Edison's progress to date in implementing real-time pricing, but recommends specific measures for furthering its use. These measures include expansion of Schedule RTP-2 or its successor to up to 50 customers; a cooperative effort of Edison, DRA, and other interested parties to review Edison's initial experimentation with real-time pricing and to formulate a longer-term plan before 1993; a new real-time on-peak demand charge for Schedules TOU-8 and TOU-8-SOP, which measures a customer's average load during on-peak hours of summer weekdays when the forecasted high temperature for the day equals or exceeds 85 degrees at Los Angeles Civic Center, based on the National Weather Service forecast; and implementation of real-time pricing for additional customer classes in the next GRC, for reasons of equity among customer classes.

Only the last of these recommendations was contested. We find the others to be consistent with our direction toward cost-based rates and will adopt them. Edison believes the extension of real-time pricing to smaller customers should await further experimentation.

We are not inclined at this time to order Edison to propose real-time schedules for additional classes. We would prefer to see if the cooperative effort that Edison has agreed to can be extended and continued with a view toward voluntary development of proposals for extending the real-time program. We will, however, direct Edison to continue monitoring its own program and to monitor the results from San Diego Gas & Electric Company's (SDG&E) R-TOU experimental rates, and PG&E's Small Commercial Interruptible Program (SCIP) and recently added Delta District dispatchable residential TOU program, as proposed by DRA. We will further direct Edison to include in its next GRC filing a showing on the appropriateness of extending the program to each of its customer classes.

<u>7.2.4 Energy Charges</u>

7.2.4.1 Off-Peak and SOP Energy Charges

Edison advocates maintaining off-peak energy charges on its time-of-use schedules at 5¢/kWh and the SOP energy charges on its SOP schedules at 3.5¢/kWh.

Edison believes that doing so promotes rate stability and customer understanding. Edison believes these charges are not far away from their EPMC levels when compared to the differential between on-peak demand charges and their full EPMC levels. Moreover, the SOP rate schedules were originally established by the Commission to increase system efficiency and mitigate Edison's minimum load problem. According to Edison, to the extent that the 3.5¢/kWh rate exceeds the marginal energy costs in the SOP periods, this level will help to achieve the original objective of SOP rate schedules.

DRA generally agrees with or does not contest these charges for Ag & Pumping schedules and for Schedule TOU-GS. However, DRA does differ with Edison's SOP energy charge for Schedule TOU-GS-SOP. DRA and the LP intervenors strongly oppose the 5¢/kWh off-peak energy charge for the LP schedules, and Edison has modified its position with respect to the TOU-8 schedule. We will return to these issues later in this decision. With the exceptions of these contested issues, we will adopt Edison's proposal for these energy charges.

7.2.4.2 On-Peak and Mid-Peak Energy Charges

Several parties disagree on proposals for using energy charges to collect coincident capacity costs which are not collected in demand charges. Edison believes that uncollected capacity costs should not be time-differentiated, and that the relationship of on- and mid-peak energy charges should be based on marginal energy cost ratios. FEA and IU agree with this approach for commercial and industrial customers. DRA used this approach for Ag & Pumping schedules only.

CLECA and DRA generally agree on another approach. Except for Ag & Pumping schedules, DRA based its energy charges on marginal energy cost ratios adjusted by a spread of uncollected coincident capacity costs to on- and mid-peak periods. CLECA designed its energy charges based on marginal energy cost ratios plus 25% (for firm service schedules) and 50% (for interruptible service schedules) of uncollected coincident capacity allocated to pricing periods by LOLP. CLECA and DRA believe that coincident capacity costs not recovered in time-related demand charges should be recovered in the energy charge associated with the time period in which they are incurred. In this way, customers will receive the most accurate price signal of the cost imposed on the utility as a result of their usage during each time period. CLECA believes this approach should be implemented to the maximum extent possible. DRA characterizes its proposal as a conservative start.

A problem with Edison's approach is that a significant portion of the coincident capacity cost is paid for by customers who contribute to system efficiency by consuming energy during off-peak and mid-peak periods.[34] CLECA believes this is unfair to high-load factor customers, since they use more electricity during the mid- and off-peak periods. Off-peak periods reflect more hours than any other period, and high-load factor customers would experience a larger share of the coincident capacity costs recovered during those periods under Edison's approach. DRA and CLECA also point out, correctly, we believe, that the wrong price signal is sent by Edison's approach.

Edison appears to acknowledge that high-load factor customers bear a disproportionate share of coincident capacity costs. As Edison's Mr. Goeddel agreed, these customers have paid

34 Of course the underlying problem is that coincident capacity costs are not adequately collected in demand charges.

rates 20% to 30% above the EPMC level for their off-peak consumption. But Edison finds problems with the CLECA/DRA approach as well. First, as a result of the new time-differentiated IERs adopted in Phase 1 of this GRC, the ratio of marginal energy costs in the summer on-peak to the summer mid-peak period increases from 1.25:1 to 1.56:1. This change alone will result in a significant increase in the summer on-peak energy charge. Edison believes that further inclusion of additional uncollected capacity costs in the ratio of marginal energy costs is not warranted at this time, for stability reasons.

Second, Edison has a fundamental disagreement with the premise of the CLECA/DRA approach. Edison believes that pricing signal to be sent to customers through energy charges is the relative cost of using an additional kWh between the on- and mid-peak periods. Edison does not believe that any price signals regarding relative capacity costs should be sent through energy charges.

We believe that the CLECA/DRA approach strikes a better balance among competing concerns of fairness, economic efficiency, and stability. Edison's concerns about energy charge relationships must be balanced against the price signal that results under its proposal, which collects a portion of coincident capacity costs in off-peak periods. In our opinion, the CLECA/DRA approach is a more accurate means of reflecting costs. Also, both CLECA and DRA recognize the need to mitigate bill impacts while at the same time progress is made towards a cost-based rate structure.

Remaining is the question of implementation. Edison is concerned with DRA's "judgmental" spread of uncollected coincident capacity costs and lack of a defined methodology. CLECA's proposal, on the other hand, seems more clearly defined. We will adopt the CLECA approach for the TOU-8 and TOU-GS schedules, but because we place more weight on the need for stability and mitigation of bill impacts, we will adopt a movement of 15% toward LOLP-based recovery.

7.3 Domestic Schedules

7.3.1 Minimum Charges

Edison proposes to retain the current 8.5¢ per day base rate minimum charge for Schedule D-LI (a discounted schedule for low-income households) and the 10¢ per day base rate minimum charge for other Domestic schedules. DRA proposes to increase the minimum charges for Domestic customers by 15% per year for the next three years to move the charges closer to the target of marginal customer costs.

Edison recognizes that except for Schedule D-LI, the base rate minimum charge for Domestic customers has not changed since the 10¢ per day level was adopted in its 1985 GRC, and that the full EPMC level of customer costs is about 25¢ per day. Edison recommends retaining the current charges because the Domestic group has been allocated a 45% increase in revenue responsibility since 1987. Edison cites the fact that the Domestic group is at full EPMC and the fact that the nonbaseline-to-baseline rate ratio (tier differential) should reach the Commission's goal of 1.15:1 as additional reasons for maintaining the current minimum charges.

DRA states that the base rate minimum charge is designed to compensate Edison for the cost incurred for metering, billing, and other customer costs. DRA notes that Edison is undercollecting from this rate component. Using the guiding principles of cost-based rates, DRA recommends using marginal customer costs as the target for setting the Domestic minimum charge for the next three years. DRA recognizes that the components that make up the Domestic schedule are nowhere near 100% EPMC, but it recommends moving closer to this goal. Over a three-year period, DRA's proposal would increase the minimum charge in phases from 10¢ per day to 15¢ per day, or 87% of marginal customer costs.

We stated in the previous section on common rate design issues that it is appropriate to temper increases related to marginal customer cost increases adopted in Phase 1. We find that DRA's proposal does exactly that. We are mindful of the increases that have been faced by Edison's domestic customers due to both Edison's increased revenue requirement and the allocation of a greater share of the responsibility for the revenue requirement. Even though the domestic customer class is at its full EPMC allocation, we still seek to attain rate structures within each class that are closer to marginal cost principles. As DRA points out, if the minimum charge does not increase, another rate component must be increased to make up the difference. We will adopt DRA's proposal for a moderate phased movement towards a cost-based minimum charge, with the understanding that it may be necessary to temper even those moderate increases in the future.

7.3.2 Tier Differential

The relationship between the rate for consumption up to the baseline allowance and the higher rate for consumption above that allowance is termed the tier differential. The ratio of Edison's nonbaseline to baseline rates was reduced from 1.39:1 to 1.33:1 in the recent ECAC proceeding.[35] Edison proposes no further reduction at this time.

Edison proposes that the annual increase in the baseline rate for this GRC cycle be limited to 2.5% above the average percentage change for the Domestic Rate Group, and that the reduction in the Domestic tier differential should be reviewed once a year in Edison's annual ECAC proceeding. TURN and DRA agree that the appropriate tier-differential reduction should be reviewed in each ECAC proceeding, but they oppose Edison's proposed limit to annual increases in baseline rates by a fixed amount.

35 D.92-01-018, p. 43.

DRA believes that incremental movement toward the goal of tier-differential reduction must be tailored to each individual proceeding. One example cited by DRA is that of a large revenue decrease. Conceivably, the rate decrease could be placed in the second tier, resulting in adjustment greater than 2.5%, with a relatively small rate impact.

TURN supports Edison's proposal to use the tier-differential ratio of 1.33:1 which was just recently adopted. TURN agrees that the Commission should retain flexibility in ECAC decisions, but for a different reason than DRA. Where DRA looks for opportunities to accelerate tier closure, TURN seeks to maintain the ability to mitigate rate shock by adopting even lower increases than those allowed under Edison's 2.5% limit. In fact, TURN disagrees with DRA's assumption that tier-differential reduction is or should be a goal, asking that we reevaluate our tier-closure policy.

We will first address TURN's request to consider once again our basic policy for tier differentials, then return to Edison's proposal for fixed limits or baseline rate increases. TURN believes that the tier differential for Edison has been reduced enough, and that the Commission has accomplished the legislative mandate embodied in Public Utilities (PU) Code § 739.7. TURN notes that § 739.7 did not abolish the baseline concept. TURN submits that the Commission should consider whether further tier reductions would violate the baseline act. TURN expresses a concern that further tier reductions would render the baseline legislation meaningless, since assertedly no conservation incentive will remain if the Commission continues its current course.

The record in this proceeding provides us with little basis on which to reevaluate our policy on tier closure. For example, as Edison points out, TURN's own witness did not provide testimony to support the contention that the Commission's current course will remove all conservation incentives.

The Commission's current course was in fact set in the decision implementing Senate Bill 987. In that decision, the Commission stated that:

> "A 15% discount on the main residential rate is a reasonable benefit to low-income customers. Realignment of the Tier 1/Tier 2 differential should be pursued so that the benefit level of the LIRA discount is commensurate with the impacts of such realignment."[36]

Thus, the Commission has already determined that tier differentials commensurate with a 15% LIRA discount should be pursued. Moreover, as already noted, we have no basis for changing that determination by this decision. Edison believes it will be appropriate for parties to evaluate the need for further closure in its next GRC. Whether we do so in that proceeding, or generically for Edison and other utilities governed by the baseline legislation, we will continue our course for the time being.

Edison's proposal for a fixed 2.5% limit is intended to ensure that impacts to baseline customers in any one year relative to other Domestic customers are not excessive. According to Edison, the goal of a nonbaseline-to-baseline rate ratio of 1.15:1 can be achieved by the 1995 GRC. No party has contested this, nor has any party provided any support as to why a ratio of 1.15:1 needs to be achieved sooner than 1995. Edison's proposal is reasonable as a guideline for setting rates in ECACs, and we will adopt it as such. While in most circumstances we would intend to follow this limit, as we have in the last three Edison ECACs, we believe some flexibility must be accorded for future determinations.

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36 32 CPUC 2d 406, 419; Conclusion of Law 3 (1989).

7.3.3 Baseline Allowances

PU Code § 739(d)(1) defines allowable ranges of electricity consumption within which the Commission shall establish baseline allowances. Edison proposes that baseline allowances for basic customers remain at 55%, the middle of the permissible range of 50 to 60% of average residential use. Edison also proposes that baseline allowances for All-Electric customers remain at the maximum allowable levels of 70% of average residential use in the winter and 60% in the summer. The proposed baseline allowances were determined by using the same methodology that was adopted in Edison's last GRC. The levels of baseline allowances proposed by Edison differ from currently effective levels only in that the most recent four years of recorded consumption data were used to develop them. DRA proposes to reduce the baseline allowances to the minimum levels permitted by law: Basic allowances reduced to 50% of average residential use and All-Electric allowances reduced to 60% of average residential use in the winter and to 50% in the summer.

DRA states that its policy of proposing a change in the baseline allowance to the bottom of the legal level is an attempt to promote conservation of a scarce resource. According to DRA, maintaining the status quo does not motivate any customer to change his or her electricity consuming habits. DRA also states that reducing the allowance will reduce volatility in Edison's revenue.

Edison and TURN oppose DRA's proposed baseline allowance reductions because of the impact on some customers' bills. TURN's witness, Mr. Marcus, showed that some customers could face bill increases of 4% to 8% solely as a result of DRA's baseline allowance reduction. Customers who heat their homes electrically would be particularly hard hit, generally losing over 100 kWh in their monthly baseline allowance. In one case approximately 250 kWh would be lost.

Edison and TURN question DRA's assertions that reduced baseline allowances will encourage conservation and minimize revenue volatility. We concur with their concerns. DRA's conservation argument is not supported by any studies in this record. Undoubtedly some customers will respond to the price signal of a reduced baseline allowance and reduce consumption accordingly. On the other hand, as Mr. Marcus' testimony explains, "keeping baseline quantities at their current levels will also continue to provide a conservation incentive by making it possible for more customers to remain within their baseline quantities."[37] TURN also points out that DRA's proposals for tier closure and reduction of nonbaseline rates in this and other proceedings may work at cross-purposes with conservation. It may well be, as TURN asserts, that large users who benefit from nonbaseline reductions have greater conservation opportunities than medium-size users do.

In all likelihood the conservation effects cited by DRA and TURN both come into play, but we are presented with no sound basis for assessing the net conservation effect of any given change in baseline allowances. Lacking such a basis, we see no reason to change Edison's proposed baseline allowances and thereby impose significant bill increases on intermediate-size customers. Nor do we find any basis for doing so in DRA's volatility argument. As TURN aptly points out, if Edison thought that revenue volatility associated with its baseline rate structure was a problem worth solving, Edison would have supported rather than opposed DRA's proposal. We will therefore adopt Edison's proposed baseline allowances.

<u>7.3.4 Submetering of RV Parks</u>

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37 Exhibit 805, p. 9.

7.3.4.1 Background

Growing numbers of persons are using RVs as their only or primary residences. CTPA, Edison, and DRA, the only parties to address this subject, generally agree that to assure fairness among RV park users and to promote energy conservation, RV park operators should be permitted to submeter electric service to such park occupants. They also generally agree that tenants should be entitled to baseline allowances and LIRA program benefits. They disagree on implementation proposals.

In response to the Commission's order in the last GRC,[38] Edison conducted a study to determine the need for a tariff extending baseline allowances or master-metered discounts to RV park tenants and owners. Any extension of baseline allowances and master-metered discounts was to take into account Edison's ability to objectively judge and realistically monitor the status of the RV tenant.[39] Edison's study concluded that most RV park tenants do not use an RV space as a permanent residence. Therefore, Edison initially concluded that no tariff change extending baseline allowances or master-metered discounts to RV parks should be made.

CTPA believes the current tariff options for RV park owners and tenants are not acceptable. According to CTPA, the Commission's decision in Case (C.) 86-01-004 and C.86-02-002,[40] which allowed RV park operators to qualify for baseline allowances under very limited circumstances, does nothing to assure that park occupants receive such benefits. At the same time CTPA complains that it does nothing to curtail the abusive

38 26 CPUC 2d 392, 615; Ordering Paragraph 45 (1987).

39 Id.

40 Richard H. Wesslink dba Lake Park Resort et al. v Southern California Edison Company, 29 CPUC 2d 253 (1988).

over-use of electric appliances by park users who are not required to pay for the actual amounts of energy they consume. As attested by CTPA witness, Mr. Imler, the special arrangements for eligibility described in <u>Wesselink</u> are so onerous that virtually no RV parks in California have qualified for service under the schedules identified therein.

<u>7.3.4.2 Positions of the Parties</u>

We will not describe each of the parties' proposals in detail because each of them changed or refined its proposal during the course of the hearings. For example, after reviewing the CTPA and DRA testimony on submetering RV parks and discussing the issues with the parties, Edison proposed establishment of Schedule DMS-3. Even that proposal has been refined in response to various criticisms and suggestions.

Edison, CTPA, and DRA now generally agree that some variation of Edison's proposed Schedule DMS-3 should be adopted. As previously noted, they also agree on general principles that submetering of long-term RV park tenants will promote fairness and energy conservation, and that long-term tenants of RV parks should be entitled to receive the same baseline program benefits (allocated on a per space basis) and low-income program benefits that other domestic customers receive. All agree that Edison needs to be able to visually inspect RV parks and review their records to determine compliance with tariff terms. No party proposed that master-meter discounts be allowed under Schedule DMS-3. The two remaining issues are whether Edison's proposed 75% occupancy rate requirement should be adopted and whether RV park owners should be able to commingle submetered spaces served under Schedule DMS-3 with nonsubmetered spaces under the same master meter.

Edison proposes that for an RV park to qualify under Schedule DMS-3, all submetered spaces would be served under a master meter which would be segregated from the other park services. A submetered space could only be occupied by a tenant using an RV as a permanent residence and renting the space on a prepaid month-to-month basis. Additionally, Edison proposes a requirement that "all long-term spaces rented month to month, commingled, average 75% occupancy rate each year."[41]

Edison believes that the average 75% occupancy rate requirement (judged by commingling all of the spaces on the master meter) is necessary for Edison personnel to objectively judge and realistically monitor the status of the RV parks and tenants. It is, according to Edison, a way of ensuring that baseline allowances are provided to tenants who are "permanent" residents.

CTPA objects to the 75% occupancy requirement, finding that it is unreasonable and that it would operate to dissuade any park operator from attempting to become eligible for the proposed DMS-3 rate. DRA opposes the 75% occupancy rate criterion as well. DRA objects to Edison's implementation plan by which the company does not intend to use the requirement as a "club" against RV park operators, as long as the operators intend to meet the requirement. DRA objects to such subjective tariff criteria regarding customer intent. DRA points out further that economic conditions beyond a park operator's control could frustrate the operator's best intentions.

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41 Proposed Special Condition 4. We assume that Edison does not intend to disqualify parks whose occupancy rate exceeds 75%. We note that considerable confusion arose from the language of Edison's proposed rule. The quoted language is embodied in a sentence which explains how a "nine-month requirement" is to be implemented. The nine-month requirement provides that "all of the spaces on the same master meter are occupied at least nine months of the year by the a tenant." (Emphasis added.) Edison states that it does not intend for the nine-month rule to be combined with the 75% occupancy factor.

To summarize, Edison claims it is not really proposing a separate nine-month requirement at all. It is only proposing a 75% average occupancy rate.

DRA also opposes Edison's proposed requirement that a specific section of an RV park must be identified and dedicated to long-term spaces. DRA believes this dedication is not necessary. DRA believes that a tenant who resides in an RV park space that is submetered, and who has prepaid the rent for one month or longer, should qualify under this schedule without regard to whether the space occupied is dedicated to long-term use as defined by Edison. DRA believes that Edison's concern is ease of inspection to determine compliance with the schedule. DRA believes that compliance can be accomplished easily enough through visual inspection of the RV park.

7.3.4.3 Discussion

We reject Edison's proposed 75% occupancy requirement because it would likely discourage too many park operators from seeking to qualify. It would also expose park operators who fully intend to achieve the occupancy rates to disqualification due to rental market variations and possibly subjective tariff application. Moreover, Edison has not demonstrated the necessity for the requirement. We believe Edison will be fully able to administer tariff requirements with adoption of the agreed-on proposals for eligibility declarations and on-site verification of books, records, and facilities. The occupancy requirement is not necessary in our opinion to "objectively judge and realistically monitor" the tariff. Nor do we find the 75% occupancy requirement necessary to give park operators an incentive to limit the portion of the park set aside for submetering. We agree with CTPA and DRA that that should be a business decision of the operator.

We note that Edison implies that CTPA and DRA oppose the 75% occupancy requirement because they misunderstand it. Given the unfortunate wording of the proposal, it would not be surprising if parties did in fact misunderstand it. However, we believe that whether they were confused or not, both CTPA and DRA oppose the requirement that "all long-term spaces rented month-to-month, commingled, average 75% rate each year."

On balance, we are persuaded that the DMS-3 tariff should require separation of a park's master-meter/submeter system from the nonsubmetered system. CTPA accepts, and its own proposal includes, this provision (even though CTPA would prefer DRA's alternative of allowing commingling of DMS-3 customers and other customers). As Edison points out, no other Edison tariff permits mixing submetered and unsubmetered spaces on the same master meter. Edison also points out that it could create administrative problems. For example, although neither DRA nor CTPA is requesting a submetering discount at this time, there is no guarantee that this will not change in the future or that other parties will not ask for such discounts. It could be problematic for the Commission to establish an administratively feasible method of doing so if there is a mixture of types of service on the same master meter. We note further, as CTPA's testimony shows, that RV parks normally separate short-term and long-term tenants in different sections.

In its reply brief Edison included a suggested Schedule DMS-3 which includes miscellaneous CTPA suggestions agreed to by Edison. Edison included two versions, one with and the other without the 75% occupancy requirement. We will adopt the latter version.

7.3.5 Schedule TOU-D

The TOU-D schedule was adopted in Edison's last GRC. Edison believes that the rate was not successful, as evidenced by the fact that there are no customers on it. Edison proposes several improvements to make the TOU option more attractive. Edison initially proposed a single TOU-D rate that: was designed revenue neutral to the Domestic group so that other customers will not subsidize the rate; was designed to collect the marginal costs of providing service during each pricing period; had a summer on-peak period of weekdays from 10:00 a.m. to 6:00 p.m. and winter on-peak period of weekdays from 10:00 a.m. to 8:00 p.m.; had a six-month summer (May through October); and had no baseline credit. Edison's proposal addressed the two important customer concerns that are the obstacles to participation on the rate: simplification of the rate and lowering the summer on-peak energy charges.

Subsequently, Edison agreed with DRA to (1) revise the on-peak hours to 10:00 a.m. to 6:00 p.m. during the winter and (2) develop a cost-based domestic revenue allocation for TOU-D customers, separate from other domestic customers, in future proceedings once adequate data is available, but not at this time.

In view of the agreement between Edison and DRA, the remaining issues revolve around the inclusion of baseline allowances and customer charges in a domestic TOU schedule. Edison proposed a single schedule with no baseline allowance or customer charge. TURN supports a revenue-neutral TOU schedule, but only if it includes a baseline credit. DRA proposes two TOU-D schedules, one with a baseline credit and one without. DRA also proposes an EPMC-based customer charge for the nonbaseline schedule. If a baseline credit is adopted, Edison still prefers only one schedule.

Edison has established the proper framework for deciding this issue by indicating that the two keys for customer acceptance, and therefore success, of this option are understandability and lower summer on-peak rates. TURN has also correctly pointed out the importance of keeping TOU options attractive to small users.

With this framework in mind, we find that DRA's two-schedule proposal best meets our objectives for a domestic TOU program. First, it responds to the concern raised by TURN that a sole TOU option without a baseline credit would distort incentives to both large and small customers. Also, although Edison prefers a single schedule for greater customer understandability, Edison's single schedule would give up the understandability it originally sought to gain by recommending no baseline allowance. It strikes us that DRA's proposal actually does more to improve acceptance and understandability by providing more options but placing them in separate schedules. For a larger user, DRA's proposed scheduled TOU-D-2 is simpler then the current option because there is no baseline provision. It also appears more acceptable because it is a cost-based rate with a lower summer on-peak charge. For a smaller customer, Schedule TOU-D-1 would retain baseline benefits. Since the current option has not attracted any customers, we believe the options proposed by DRA are particularly appropriate. We therefore adopt DRA's proposal.

7.4 LSMP Schedules

7.4.1 Customer Charges

7.4.1.1 Schedule GS-1

Edison proposes to change the customer charge on Schedule GS-1 according to CEPC to provide rate stability. DRA proposes to increase the customer charge on LSMP schedules, including GS-1, to accomplish a match with at least marginal cost. Where feasible, DRA proposes to reach EPMC customer charges before Edison's next GRC. For Schedule GS-1, DRA proposes an increase in the customer charge from its present 30¢ per day to 40¢ per day.

Edison states that customers on Schedule GS-1 are generally commercial customers with a low monthly usage of approximately 900 kWh. Their bills are therefore very sensitive to changes in the customer charge. Under DRA's proposed customer charge increase, approximately 75,000 of Schedule GS-1 customers would experience annual bill increases between 15 and 33%.

In our opinion, the problem with Edison's proposal is that it makes no progress towards a more cost-based rate structure. Edison has not argued that Schedule GS-1 should not have a cost-based customer charge; it has merely given the maximum weight to rate stability. We believe a better outcome would be to make some progress toward an EPMC-based customer charge. When we evaluate bill impacts, it is appropriate to consider absolute dollar impacts as well as percentage increases. A 33% increase which raises the customer charge by approximately $3.00 per month is not insignificant, but is less significant than one with a larger dollar impact. We believe DRA's proposal is a reasonable step to take.

DRA also proposes increasing the GS-1 customer charge by one-fourth of the difference between its January 1992 and its EPMC levels in Edison's next three annual ECAC proceedings. We generally concur that it is appropriate to continue progress towards a cost-based customer charge between GRCs. DRA's plan for doing so in measured steps appears to be a reasonable guideline. However, we will not adopt DRA's proposal as a firm plan. Instead we will leave the final determination of how much further progress be made to future proceedings. The need for rate stability can be better evaluated in the light of then-existing circumstances.

7.4.1.2 Schedule GS-2 and Schedule TOU-GS

DRA points out that the customer charges in some GS schedules are considerably below even a marginal cost-based customer charge. As with the GS-1 schedule, DRA proposes moving the GS-2 customer charges one-fourth of the increase needed for an EPMC-based charge. Edison proposes to change the customer charge for Schedule GS-2 by CEPC and the customer charge for Schedule TOU-GS by CEPC plus 10%. Edison believes that the DRA proposals for an approximate 33% increase for each schedule are excessive.

We believe some movement toward EPMC-based charges should be accomplished. Compared to Schedule GS-1, however, the increases under DRA's proposals are relatively significant in dollar terms. For example, DRA's proposed customer charge for Schedule GS-1 is $12. DRA proposes a charge of $48 for Schedule GS-2. A better balancing of stability and costs would be to increase the customer charge for Schedule GS-2 by CEPC plus 10% and for Schedule TOU-GS by CEPC plus 20%.

We will adopt the same principle for increases in these customer charges between GRCs that we did for Schedule GS-1. Thus, in ECAC proceedings we would expect parties proposing increases in customer charges to follow the guidelines of CEPC plus 10% and CEPC plus 20% for Schedules GS-2 and TOU-GS respectively. Again, the need to temper such increases may be considered in those proceedings.

7.4.1.3 Schedule TC-1

Edison recommends that the customer charge for Schedule TC-1 be set at its full EPMC level. Since little movement to a fully cost-based charge is required, the effect on customers' bills is negligible. DRA and CAL-SLA agree that an EPMC-based customer charge can be adopted for this schedule.

Edison notes that DRA's proposed customer charge is 15% above its EPMC level. We agree with Edison that there is no justification for setting the customer charge in excess of the full EPMC level.

7.4.2 Nontime-Related Demand Charges

Edison proposes to unbundle demand charges for Schedule GS-2 into time-related and nontime-related components, and to change nontime-related demand charges on Schedule GS-2 by CEPC and on TOU-GS and TOU-GS-SOP by CEPC plus 10%. DRA proposes to increase the nontime-related demand charges on these schedules to $4.00 per kW.

DRA points out that, in general, the increases required to achieve EPMC-based nontime-related demand charges are smaller than those required for customer charges. DRA's recommendation for $4.00 per kW is made in conjunction with its proposal for a $0.50 per kW increase in the next ECAC.

We will use the same approach that we used for LSMP customer charges in balancing stability and movement toward EPMC-based charges. Accordingly, we will adopt increases of CEPC plus 10% for the nontime-related component of Schedule GS-2 and CEPC plus 20% for Schedules TOU-GS and TOU-GS-SOP. These same rates of increase would be observed as guidelines in proceedings between GRCs until full EPMC charges are achieved.

7.4.3 SOP Energy Charges

Edison proposes to establish the off-peak energy charge for Schedule TOU-GS and the SOP energy charge for Schedule TOU-GS-SOP at 5¢/kWh and 3.5¢/kWh, respectively. As previously noted, DRA does not oppose the off-peak charge for this schedule. DRA proposes a 4¢/kWh SOP rate because it is closer to the EPMC level for this time period. Edison states that it was unable to evaluate the implications of raising the SOP energy rate from 3.5¢/kWh to 4.0¢/kWh because DRA did not provide its final TOU-GS-SOP schedule proposal.

We find no compelling reason for raising the SOP rate as proposed by DRA. Edison's proposal will be adopted.

7.5 LP Schedules

7.5.1 Nontime-Related Demand Charges

Edison proposes a full EPMC-based nontime-related demand charge for subtransmission service. Edison's general proposal for primary and secondary service is to increase the charges by CEPC plus 10%. In view of the off-peak energy charges adopted in this decision, Edison proposes increasing the Schedule TOU-8-PRI charge by CEPC plus 20% to ensure that the energy charge on that schedule will be less than the energy charge on Schedule TOU-8-SEC. Edison originally proposed no nontime-related demand charge for subtransmission customers because those customers cause Edison to incur no distribution costs in serving them, and, under Edison's proposal, transmission costs were allocated entirely based on coincident demand. Since we are adopting DRA's allocation of marginal transmission cost to coincident and noncoincident demand (approximately 92% and 8% respectively), Edison believes that the nontime-related demand charge for subtransmission service should be set to reflect the noncoincident share of transmission cost at its EPMC level.

As noted earlier, DRA proposes to move nontime-related demand charges for LP customers to full EPMC in this proceeding, phased in, in some cases, over the three-year GRC cycle. Accordingly, DRA proposes to set the nontime-related demand charges at $0.35 per kW for subtransmission, $3.00 for primary, and $4.00 for secondary, with additional increases in intervening ECAC proceedings. IU recommends increasing the charges by 50% of the distance between present rates and full EPMC. FEA also believes that demand charges are far below EPMC and should therefore be increased. CLECA recommends moving the charges to full EPMC for interruptible customers and 50% toward full EPMC for firm customers.

We find it is reasonable to increase nontime-related demand for subtransmission service as proposed by Edison. Edison states that its proposed changes for the primary and secondary nontime-related demand charges are intended to move these charges toward a level recovering 100% of marginal distribution costs. In our opinion, however, limiting the changes to CEPC plus 10% or even 20% does not provide enough movement toward EPMC levels. We adopted increases of CEPC plus 20% for nontime-related demand charges in the TOU-GS schedules. For the LP schedules, however, we believe it is appropriate to give even greater weight to marginal costs. As noted by IU, the TOU-8 demand charges presently recover only about 47.2% of EPMC demand-related costs. It is clear that the intervenors who represent customers taking service on those schedules give greater weight to marginal costs. We will, therefore, provide for movement of 50% of the distance to EPMC for primary and secondary schedules.

7.5.2 Time-Related Demand Charges

Edison proposes to change time-related demand charges by CEPC plus 20% for subtransmission service and CEPC plus 10% for primary and secondary service. Edison proposes to increase the time-related demand charges in the SOP schedules by CEPC because they are close to the EPMC level. As previously discussed, DRA has reached agreement with Edison that a moderate increase in time-related demand charges should accompany DRA's recommended real-time on-peak demand charge option.

CLECA states that Edison's rates are a long way from recovering coincident capacity costs in the various on-peak time periods. Currently, only 39% of summer on-peak costs are recovered in that period even though 83% of those costs occur then. CLECA advocates gradual movement of these charges toward their EPMC levels with a faster rate of increase for interruptible customers. FEA agrees with the charges proposed by Edison. IU's proposal results in smaller increases (in absolute terms) than those proposed by Edison, but it recovers a greater portion of demand costs.

There is broad-based agreement on the need for tempered increases in on-peak demand charges. We find that Edison's proposal reasonably balances rate stability and movement to EPMC charges. Further, the increases are moderate and therefore in accord with the agreement reached by Edison and DRA. We will adopt Edison's proposal.

FEA raises a concern that the on-peak demand change in DRA's November 26, 1991 proposal for TOU-8 rates is higher for the primary class then it is for the secondary class. We agree that it is less costly to provide capacity to serve higher voltage customers, and, therefore, that the adopted rate design should not contain a reversed relationship of on-peak demand charges.

7.5.3 Energy Charges

7.5.3.1 Off-Peak Energy Charges

One of the more contested issues in this proceeding was Edison's proposal to maintain its off-peak energy charge at 5¢/kWh on the TOU-8 schedules. According to Edison, its proposal promotes rate stability and provides customers with long-range price signals so that they can make more accurate investment decisions. Also, Edison explains that any reduction in the 5¢/kWh rate would cause the Schedule 1-5-A off-peak energy charge to be below marginal energy cost. That schedule provides a fixed 2.5¢/kWh reduction from the firm off-peak energy rate.

CLECA, DRA, FEA, and IU oppose this charge, arguing that it should be reduced. IU, for example, notes that it has been maintained at the same level since Edison's last GRC, and that LP customers have long since sought to have it reduced toward Edison's marginal costs.

Edison acknowledges that the charge exceeds the full EPMC level for each of the TOU-8 service levels and for both the summer and winter periods. Edison further acknowledges that the charge results in inaccurate price signals. In rebuttal testimony, Edison presented an alternative proposal for a reduction which, it believes, should be adopted if the Commission decides to adopt lower off-peak energy charges. Later, in its February 1992 update testimony, Edison agreed that in the wake of Commission decisions in Phase 1 of this GRC and the recent ECAC proceeding, its primary recommendation of 5¢/kWh was no longer appropriate for the LP schedules. Edison now recommends that its alternate proposal be adopted.

Edison has removed much of the controversy with its alternative proposal. It provides for movement of the charges of up to one-half the distance to their full EPMC levels in this proceeding. Edison also proposes a floor of marginal cost, which should effectively resolve the Schedule 1-5-A problem on an interim basis until January, 1993 when that schedule is terminated.[42] FEA argues that moving one-half the distance to EPMC does not go far enough and IU proposes 75% movement, but we disagree. There is still a need for a degree of stability, and we believe that Edison has reached an appropriate balance in this case. We recognize that to the extent that capacity costs are not collected in energy charges, they must be collected in demand charges, and we have already determined a need for stability in those charges as well.

Two aspects of Edison's now-preferred alternative proposal require discussion. First, Edison proposes to set the on-peak and mid-peak energy charges based on marginal energy cost ratios without recovery of uncollected coincident capacity costs in these charges. We have determined elsewhere in this decision that the approach advocated by DRA and CLECA (of adjusting marginal cost ratios for determining n- and mid-peak energy charges) is preferable to the Edison approach. We are not persuaded that we should change that determination in order to reduce off-peak energy charges towards EPMC.

Second, Edison proposed to increase the nontime-related demand charge on Schedule TOU-8-PRI by CEPC plus 20% and on Schedule TOU-8-SEC by CEPC plus 10% to ensure that the energy rates on Schedule TOU-8-PRI are less than those on Schedule TOU-8-SEC. Again, we have already addressed this proposal in another part of this decision and will not change that determination as a result of this change. We note that Edison determined it was not necessary to follow this recommendation in its February, 1992 update proposal. There, Edison used its original proposal of CEPC plus 10% for both secondary and primary schedules.

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42 Edison proposes to apply the 2.5¢/kWh credit until the off-peak rates equal marginal cost. The remainder of the credit is then allocated an on equal cents per kWh basis to the on- and mid-peak periods.

7.5.3.2 Relationship of TOU-8 Primary and Secondary Energy Rates

Edison believes that TOU-8-PRI energy charges should not be greater than TOU-8-SEC energy charges because energy line losses at secondary voltage exceed those at primary voltage. Edison points out that DRA's proposed energy rates for TOU-8-SEC are generally below there for TOU-8-PRI. As with the reversed relationship of on-peak demand charges noted by FEA, we agree that the adopted rate design should not include higher energy charges for the primary schedules than for the secondary schedules.

7.5.4 Suballocation of Firm and Interruptible Schedules

CLECA states that in analyzing LP rate design, it became apparent that current interruptible customers can be moved more quickly toward cost-based rates without significant bill impacts than can firm customers. According to CLECA, interruptible customers have lower-cost usage patterns and thus are better suited to more significant changes. CLECA states that interruptible customers may even benefit from such changes since cost-based rates will tend to lower their overall bills. Accordingly, CLECA proposes separate rate development for firm and interruptible customers in the LP class.

CLECA proposes to implement this separate rate development by a suballocation of the revenue requirement which is allocated to the LP classes. CLECA suballocates this revenue to firm and interruptible customers based on the load characteristics of these subgroups. CLECA states that because the split is done on an EPMC basis, it results in a cost-based suballocation which reduces internal LP class subsidies. The split between the firm and interruptible customers is performed by assuming that all load is firm (i.e., without any interruptible incentives) so it reflects only the usage characteristics of the two groups; thus, the firm service level rates for interruptible customers will differ from the proposed rates for firm customers in only two ways: (1) they are closer to full EPMC/full LOLP; and (2) they reflect a customer group with somewhat different usage patterns.

Edison opposes this suballocation for several reasons. First, CLECA calculated the separation on a customer, rather than a load basis. Thus, a customer with a total load of five megawatts (MW) and a firm service level of three MW and is included in the interruptible subgroup for purposes of suballocation revenue even though the majority of its load is served on the firm service schedule. According to Edison, this generates a mismatch between the revenue allocation and rate design and the applicability criteria for CLECA's proposed firm and interruptible rates. Edison also points out that CLECA did not investigate the impact of this suballocation on firm customers, and further, that CLECA agrees that similar results can be achieved by moving demand and energy charges toward their cost-based levels. Firm and interruptible customers have different costs (aside from avoidance of coincident capacity cost) because of their load characteristics, and cost-based rate components can properly apportion these costs without a suballocation. Finally, according to Edison, if I-3 and I-5 customers receive their fixed ¢/kWh credit from the CLECA-proposed firm rates, then they will be in the wrong subgroup until those schedules are cancelled.

DRA states that it has no significant objection to CLECA's suballocation proposal. On the other hand, DRA refers to it as complicated, and it believes that the differences in types of service between the two groups are "not entirely clear-cut." DRA notes that both groups have the same TOU periods, the same general pattern of demand and energy charges, and the same range of load size. The major difference that DRA finds is in their ability to tolerate rapid movement to cost-based rate structures.

DRA does object to the suballocation unless two conditions are met. First, customers who would be classified as "firm" should have an interruptible option. Second, the suballocation should be recognized as interim, pending movement of both groups to cost-based rate designs.

We believe that DRA's second condition for approval, that the suballocation should only be interim, highlights an important reason why the proposal should not be adopted. Edison, CLECA, and DRA appear to agree that the proposal has value largely or only because the LP schedules are not sufficiently cost-based. But the reason they are not cost-based is largely due to our continuing concerns about stability. We are not persuaded that CLECA's path to the goal of cost-based rates better resolves our stability concerns than the path proposed by the other parties. CLECA acknowledges, for example, that it did not evaluate the impact of suballocation on the firm group. Even though interruptible customers may be able to "tolerate" cost-based rate movements, which we acknowledge makes the proposal an attractive one, we are concerned about possibly trading an unknown impact on firm customers for that benefit.

Moreover, we have reservations about using a customer's interruptible status as a basis for separating the groups. As DRA points out, the differences in the costs of serving them are not clear-cut yet the similarities are numerous.

We agree with CLECA that the problem of placement of the I-3 and I-5 customers is a relatively minor transitional problem which alone does not alone justify rejecting CLECA's proposal. Similarly, the complexity factor suggested by DRA, while not insignificant, does not alone justify hesitation to move to a more cost-based rate structure. However, when these concerns are combined with our stability concerns and our doubts about the long-term conceptual basis, we are persuaded that the proposal should not be adopted.

7.5.5 Rate Design Methodology for Schedule TOU-8-SOP

Edison's proposed methodology for the TOU-8-SOP rate schedules is to design the rates revenue neutral to the applicable counterparts; determine the revenue deficiency from these revenue neutral rates; add this deficiency to the TOU-8-SOP rate schedules' revenue requirements; and redesign these schedules. Edison found that a more complex methodology which was adopted in the last GRC[43] resulted in an unstable relationship between the TOU-8 and TOU-8-SOP energy rates. Edison advocates its approach as one which is less complex, less time-consuming, and one which results in a more stable relationship between schedules.

DRA proposes to design these schedules based on an iterative methodology which suballocates revenues to those customers who benefit on these schedules. When few or no customers are currently served on the optional tariffs, as is the case for SOP rates, DRA recommends use of an iterative process involving extensive customer billing data to compute billing determinants and allocate revenues for the new options. DRA believes that this method more accurately represents the usage characteristics of customers who are likely to choose the optional rate. DRA criticizes Edison's method as a shortcut for such a suballocation. DRA acknowledges the complexity of this design process but notes that it accomplished the suballocation using a personal computer.

We will adopt Edison's proposal. As Edison points out, rate design methodologies should follow cost-based principles to the extent possible, but should also be simple and understandable. In our opinion, Edison's proposed methodology better meets these tests. Edison has shown that the current iterative methodology led

43 26 CPUC 2d 392, 603; Finding of Fact 378 (1987).

to unstable rate relationships among schedules, which runs counter to the ratemaking goal of customer understanding and acceptance.

7.5.6 Schedule TOU-8-CR-1

Schedule TOU-8-CR-1 was adopted in Edison's 1988 GRC[44] to promote incremental usage of electricity by LP customers above their "base" usage. Presently, 13 customers are served on this rate schedule. Edison estimates that these customers saved $3.2 million compared to charges under otherwise applicable rates, based on 1990 billing parameters. Edison believes that this option has resulted in increased sales on its system and has benefited other ratepayers due to the contribution to fixed costs from those sales that would not have otherwise occurred.

In this GRC Edison proposes to revise the current Incremental Sales Rate (ISR) billing procedure to bill "base" usage on Schedule TOU-8 and incremental usage on Schedule TOU-8-CR-1. Edison also proposes an interruptible option for Schedule TOU-8-CR-1 under which the "base" usage will be billed on the customers' applicable interruptible rate schedule and the interruptible portion of incremental usage billed on Schedule TOU-8-CR-1 with the capacity cost component of the demand charge which is avoided set to zero.

DRA advocates elimination of this schedule and rejection of the proposed interruptible version. If it is retained, DRA proposes that the schedule be closed to new customers and eliminated by January 1, 1996. DRA supports Edison's revised billing procedure if the schedule is retained.

DRA opposes the continuation of this rate option because the incremental sales could have occurred under the normally applicable rate schedules, in which case other ratepayers would have realized a larger contribution to fixed costs; there is no

44 Id., 604; Finding of Fact 394.

risk of a higher rate to customers who select this option as a result of increase or reduction in avoided costs; and the fixed charge on this schedule does not convey any price signal. DRA acknowledges that the incremental consumption of these customers has probably been beneficial to all customers. DRA is still concerned that these customers have received a windfall.

We share DRA's concern about potential windfalls. However, despite past shortcomings, we believe that with the improvements proposed by Edison, the ISR program can and should remain as a tariff option for now along with the proposed interruptible option. At this time we would prefer to strengthen controls on the program to better ensure its goals are met rather than eliminate it.

We agree with DRA that the important question is whether customers choosing this schedule would increase their consumption even under "normal" tariffs. DRA believes that Edison does not have the information it needs to make that determination. DRA notes that Edison has not done any study to determine whether these customers would have expanded their economic activities in Edison's service territory without the ISR. DRA believes that the Commission should make the determination of a customer's likelihood of increasing consumption upon the filing of an application by Edison for approval of an ISR-type special contract.

We are not convinced that formal Commission proceedings are necessary for determining eligibility for this type of rate. Edison has agreed to add a requirement that customers sign an affidavit that in the absence of the ISR option they would not increase their load. DRA acknowledges this will provide more assurance regarding the true incremental nature of the schedule. We agree that the affidavit is a reasonable step towards tighter control of the ISR program.

With regard to DRA's concern that customers on this schedule receive a windfall because they face little risk of increase, Edison counters that these customers might have experienced bill increases if avoided energy costs had taken an opposite direction and increased in recent years. In any event, the large benefit received in recent years will be decreased by approximately 60% in the future as a result of Edison's revised billing procedure. Finally, by eliminating the fixed charge, better price signals will be sent.

While we approve the continuation of the schedule and leaving it open to new customers at this time, we are not convinced of its long-term usefulness. As Edison's LP rate continue to evolve towards a more cost-based structure, the usefulness of an ISR-type option can be expected to decline. We believe it will be appropriate to revisit the question of continuing this schedule in Edison's next GRC. Accordingly, we will direct Edison to study and report on the need for and appropriateness of continuing this option in its next GRC filing. As part of that study, Edison shall evaluate whether the affidavit requirement remains sufficient to ensure that the load on this schedule is truly incremental.

7.5.7 Spot-Pricing Amendment Energy Charge

Edison and DRA have agreed on the extension of this option through summer of 1993 and the revision of the current billing procedure, but they disagree on the energy charge for eligible purchases. DRA proposes to increase the current 7¢/kWh minimum rate to 8¢/kWh. Edison proposes to continue the current rate.

DRA states the Commission originally accepted the 7¢/kWh Spot-Pricing Amendment (SPA) rate because it resulted in a margin contribution of 3¢/kWh. DRA is concerned that 7¢/kWh is not sufficiently high to ensure that a 3¢/kWh is realized in the future. DRA notes, for example, that in the summer of 1990 the avoided on-peak energy cost varied from 4.2¢/kWh to 4.8¢/kWh, thus providing a contribution ranging from 2.2/kWh to 2.8¢kWh. DRA believes there should be a greater certainty that the 3¢/kWh contribution will be attained.

Edison points out that in the summer of 1991, avoided on-peak energy costs dropped to 3.5¢/kWh, and concludes that other ratepayers are adequately protected if the SPA rate remains at 7¢/kWh.

One thing clear from the showings of Edison and DRA is that the avoided energy cost changes significantly from one year to the next. It ranged from 4.2¢ to 4.8¢ in the summer of 1990 then dropped to 3.5¢ a year later. This illustrates the legitimacy of DRA's concern. Edison states that based on the gas price of $2.83/MMBtu adopted in the recent ECAC, the summer on-peak marginal energy cost is approximately 4.5¢/kWh. Using this value as a forecast proxy for the avoided on-peak energy cost, we find it is reasonable to adopt a minimum rate of 7.5¢/kWh to provide reasonable assurance that the 3¢/kWh contribution is realized for the future.

We note that Edison and DRA have agreed that this tariff option should be reevaluated in the 1993 Rate Design Window proceeding. In our view, if the option is to be maintained, it will be appropriate for parties to reevaluate this minimum charge as well in the light of then-current avoided costs and marginal costs.

7.6 Ag & Pumping Schedules

7.6.1 Customer Charges

To provide rate stability, Edison generally proposes to change customer charges on Ag & Pumping schedules by CEPC. The only exception is Schedule TOU-PA-5, where the proposed customer charge is set at the same level as the other customer charges on open AG-TOU rate schedules. CFBF supports Edison's recommendation. DRA proposes increases in customer charges for Schedules PA-1, TOU-ALMP-2, TOU-PA-1, and PA-2 in this proceeding and further increases in the next two years to move the charges closer to the full EPMC level.

DRA points out that some components of Edison's rate schedules are nowhere near their 100% EPMC level. DRA proposes customer charge increases in the magnitude of 10% per year for Schedules PA-1, TOU-ALMP-2, and TOU-PA-1. For Schedule PA-2, DRA proposes to increase customer charges on the order of $1.00 per year beginning in the Test-Year and continuing for the next two years. DRA recommends that all other Ag & Pumping customer charges remain unchanged.

DRA states that its "measured and steady" increases go farther in developing an equitable allocation of costs than Edison's recommendations do. Further, DRA states that if its recommendation is adopted, Ag and Pumping rate schedules will be much closer to EPMC by the next Edison GRC than they would otherwise be under Edison's recommendation.

Again, as we have determined with other schedules, the problem we find with Edison's proposal of limiting increases to CEPC is that it makes too little progress towards cost-based rates for schedules which are far from being cost-based. On the other hand, DRA proposes no increases at all for all but four Ag & Pumping schedules.

We believe that the customer charges in these other schedules should be increased by CEPC as proposed by Edison. We also adopt DRA's proposal to increase the customer charge on Schedules PA-1, TOU-ALMP-2, and TOU-PA-1 by 10% annually, and to increase the charge or Schedule PA-2 by $1.00 in this decision and in each of the next two years. We concur with DRA that these increases are conservative even with the possibility that marginal customer cost measurements could change in the future. For example, the current customer charge for Schedule PA-2 is $23.30

per month.[45] Edison's proposal to increase the charge by CEPC results in no increase[46] yet the marginal customer cost is $83.27 and the EPMC-based customer cost is $108.09.[47]

7.6.2 Nontime-Related Demand and Connected Load Charges

Edison proposes that nontime-related demand charges and connected load charges on Ag & Pumping schedules be changed by CEPC or CEPC plus 10%. Specifically, Edison proposes that nontime-related demand and connected load charges on basic Schedules (PA-1 and PA-2), and closed schedules (TOU-PA-1) be changed by CEPC to provide rate stability by maintaining the current rate structure relationships. Edison proposes that nontime-related demand and connected load charges be changed by CEPC plus 10% on open TOU schedules in order to provide better price signals to customers.

DRA proposes to phase in increases to nontime-related demand charges on the order of 65¢/kW per year beginning in the Test-Year and continuing for the next two years. These increases would be for Schedules TOU-PA, TOU-PA-B, TOU-PA-4, TOU-PA-5, and TOU-PA-SOP. DRA agrees with Edison's recommendation to institute a nontime-related demand charge for PA-2, starting out at $1.40/kW for the Test-Year. DRA proposes increasing the charge on this schedule by 65¢/kW per year for the next two years.

DRA points out that the nontime-related demand charges on several Ag & Pumping schedules are significantly below marginal cost. For example, the charge for several schedules was $1.30/kW in 1991, yet the marginal cost is $3.36/kW and the EPMC value is $4.52/kW. Given this disparity, DRA believes increases of $0.65/kW

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45 Exhibit 635, p. I-244.

46 Id., p. II-121.

47 Exhibit 703.

are moderate ones which take the economic concerns of Ag & Pumping customers into account. DRA notes that its recommendation will not bring these charges to their EPMC level by the next GRC but only to the marginal cost level. DRA criticizes Edison's recommendation to increase these charges by no more than CEPC plus 10% because the resulting charge would scarcely be closer to EPMC by the next GRC than it is today.

CFBF concurs with Edison's recommendations and opposes those of DRA. ACWA opposes DRA's proposed increases and, generally, the use of EPMC principles to set demand charges.

It is difficult for us to view DRA's proposal as "moderate" when, over a three-year period, it adds $1.95/kW (3 x $.65) to a charge of $1.30/kW.[48] However, we do not believe it is "extreme" as Edison claims. The disparity between the charge and the related marginal demand cost, and the inaccuracy of this price signal, render that characterization misleading at best. We do concur with Edison's later characterization that they are "excessive," and find that an appropriate balance of stability concerns and bill impacts on the one hand, and closing this glaring cost-rate gap on the other hand, is an intermediate solution. Edison proposes increases of CEPC for the basic schedules and increases of CEPC plus 10% for open TOU schedules. We will use this framework and adopt increases of CEPC plus 10% for the basic schedules and CEPC plus 20% for the open TOU schedules. Increases of this magnitude should send more accurate price signals to customers than those proposed by Edison. This approach is similar to the one we are adopting in this decision for nontime-related demand charges for LSMP schedules. We also adopt for the Ag &

48 We note that of these charges have been raised. For example, the charge on Schedule TOU-PA is now $1.35/kW. (Exhibit 635, p.I.-251.)

Pumping class these same rates of increase as a guideline for further increases in proceedings between now and the next GRC.

We have already addressed ACWA's contentions regarding shortcomings of the EPMC methodology in deciding revenue allocation matters. We do note, however, that not even DRA recommends implementing EPMC-based nontime-related demand charges for all Ag & Pumping schedules before Edison's next GRC. Our interim goal is the same as DRA's: to move these charges toward marginal cost.

7.6.3 Schedule AP-I

Edison proposes to maintain the current structure of Schedule AP-I. Edison also proposes to maintain the current 1.5¢/kWh interruptible credit until January 1, 1993. Effective January 1, 1993, the credit level for AP-I would be revised to reflect the Commission's adopted level of credits in this proceeding.

DRA opposes Edison's proposal to establish a new Schedule TOU-8-1 for the LP customer class because it provides interruptible credits on a flat cents/kWh basis.[49] Consistent with that position, DRA proposes that Edison introduce time-differentiated interruptible credits in the AP-1 schedule rather than create a new TOU-PA-SOP-1 schedule for the Ag & Pumping class.

According to Edison, DRA's proposal has the effect of providing the interruptible credit to all interruptible Ag & Pumping customers by demand and energy charge components by pricing period. Edison considers that to be inappropriate. Some Ag & Pumping rate options do not have time-differentiated energy and demand charges and others do not even have demand charges. If every schedule's interruptible credit is provided according to the structure of that schedule, then the number of Ag & and Pumping schedules will be doubled, with one for firm service and another

49 We address this proposal elsewhere in the decision.

for interruptible service. Also, there are five different types of TOU periods used on Ag & Pumping schedules and 20 different firm service rate options. Edison states that as a result of the variety of Ag & Pumping rate structures, the only simple and practical way to provide the interruptible credit to Ag & Pumping customers is on a flat ¢/kWh basis.

DRA has not provided detailed support for its proposal, whereas Edison has shown that tariff structures for the Ag & Pumping class are significantly different from those of the LP group and would make DRA's proposal complicated to implement. We adopt Edison's proposals to maintain the structure of Schedule AP-1 and to establish Schedule TOU-PA-SOP-1.

7.6.4 Schedule TOU-PA-3

The TOU-PA-3 schedule is an optional rate schedule which provides Ag & Pumping customers with options to select from two different peak-hour periods. Since its adoption in Edison's last GRC, customers have shown no interest in this schedule. Edison proposes to eliminate Schedule TOU-PA-3 because there are no customers on the schedule even though it has been available for four years. Edison's Customer Service personnel are aware of no customers who are interested in the rate.

DRA also recommends that Schedule TOU-PA-3 be eliminated. DRA notes that with the current menu of Ag & Pumping schedules, termination of this schedule represents no significant reduction in the choices for Ag & Pumping customers. DRA believes the historical evidence of lack of interest in this rate schedule indicates the appropriateness of its elimination. DRA also notes that if this schedule is retained, significant rate changes must be made to it to bring it up to cost-based rates.

ACWA states that lack of customer interest is understandable. The schedule was developed as an option for water pumpers who pump for 24-to-96 hours around-the-clock runs. California has been in a drought since the schedule was established, so little surface water has been available to pumpers who could otherwise use Schedule TOU-PA-3. ACWA believes the schedule should be retained to see if it proves attractive to water pumpers once California's surface water supplies return to normal. ACWA also refers to a study which shows that Central Valley agricultural customers could benefit under a PG&E rate schedule which is similar to Edison's Schedule TOU-PA-3.

We find insufficient reason to retain this schedule, and will therefore approve Edison's proposal to cancel it. The Central Valley study relied on by ACWA included 116 accounts, but only 12 were located in Edison's service territory. Edison analyzed the study data and determined that only one account could have benefited from PG&E's equivalent schedule, and that was more than eight years ago.

Notwithstanding California's continuing and severe drought conditions, we concur with Edison and DRA that the lack of any customers is a compelling argument for cancelling the schedule and thereby simplifying Edison's rate structure. Finally, as Edison notes, such an option can be reestablished in the future in the unlikely event it is needed.

7.6.5 Schedule TOU-ALMP-2

Schedule TOU-ALMP-2 has been closed to new customers since 1988. It has a low customer charge and no demand or connected load charge, but it does have TOU energy charges. There are more than 1,300 customers on the schedule. The TOU-ALMP-2 rate group is the farthest from a full EPMC revenue allocation in this proceeding.

Edison proposes to terminate Schedule TOU-ALMP-2 on June 4, 1995. Until it is cancelled, Edison believes that the current energy rate relationships by period should be maintained. DRA agrees that the schedule should be terminated as proposed by Edison.

CFBF strongly recommends that the schedule be retained. Once it is at or near its EPMC revenue allocation share, CFBF recommends that the schedule be reopened. CFBF acknowledges that the schedule lacks the price signal of a demand charge, but it believes customer understandability and acceptance should be emphasized. CFBF notes that even though the schedule has been closed to new customers since 1988, it is highly popular with the agricultural class. Currently, there are over 1,379 customers on the schedule compared with 1,081 customers in all other TOU schedules combined.

CFBF argues that: the fact that there is no demand or connected load charge should make no difference if the schedule is recovering its full EPMC allocation; it should make no difference whether collection is made through multiple charges or just one charge; the specific design of a rate schedule should be aimed at customer acceptance; and if the schedule recovers its full EPMC revenue responsibility the utility should be ambivalent to the specific structure. CFBF argues further that it is due to the simplicity of this schedule that the number of customers has not significantly decreased since 1988 when it was closed to new customers. CFBF offers additional arguments for retaining Schedule TOU-ALMP-2:

1. The schedule is a TOU schedule which provides a reasonable alternative to the PA-1 and PA-2 schedules, and promotes energy use in off-peak periods without making tracking of energy use overly complex and

2. Although the schedule is currently some distance from its EPMC allocation, it is because of the marginal cost changes adopted in this proceeding that it moved away from EPMC. CFBF agrees with the need to move the schedule toward what has only recently been established to be its EPMC allocation. As long as the charges on the schedule are being set to move the revenue collected from the schedule toward EPMC,

> then the customers on this schedule should not be penalized for the changes which have only recently taken place.

Stated simply, we believe CFBF gives too little weight to the Commission's goal of cost-based rates which signal to customers the cost-effects of their consumption. We reject the notion that a utility should be indifferent to a rate structure as long as it collects its revenue requirement and the customers are satisfied. As we have discussed repeatedly in this decision, we embraced the use of marginal cost principles for both revenue allocation and rate design long ago. Demand charges are essential for informing customers about the generation, transmission, and distribution costs incurred by the company. Price signals are particularly important for Schedule TOU-ALMP-2 since it has a number of high-use customers. Schedule TOU-ALMP-2 does not properly inform customers of the costs they impose; customers can impose different costs on the system, yet have identical bills. One result of a schedule like TOU-ALMP-2 is to encourage low-load factors and high costs of service.

It is true that Schedule TOU-ALMP-2 has TOU energy charges, but there are numerous other Ag & Pumping schedules that do as well. Undoubtedly, its simplicity has attracted customers to this schedule in the past, and has encouraged current customers to remain on the schedule. But we cannot ignore the possibility or even the likelihood that many customers remain on the schedule because it lacks a demand charge[50] and because it is allocated a revenue responsibility below that commensurate with its cost by as much as 17%.

We recognize the strong customer preference for this schedule, but we conclude that it should be terminated in three

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50 We do not equate simplicity with lack of a demand charge.

years as proposed by Edison. This approach will inform customers that the schedule is not cost-based yet give them time to determine appropriate alternatives. We note that despite CFBF's argument to the contrary, termination of this schedule is in no way a "penalty" for the revised revenue allocation and MCRR determination adopted in this decision.

7.7 SL Schedules

7.7.1 Facilities and Other Nonenergy Charges

Schedule LS-2 is applicable to customer-owned unmetered electric service for lighting of streets, highways, other public thoroughfares, and publicly operated automobile parking lots. Edison has included the cost of auxiliary relay equipment and aluminum conductor in the calculation of facilities costs to be paid by LS-2 customers. CAL-SLA recommends that there be no facilities charge for LS-2 multiple service.

7.7.1.1 Relay Equipment Costs

CAL-SLA opposes Edison's inclusion of $370,000 for relay equipment costs in the facilities costs for Schedule LS-2. CAL-SLA believes that this amount should be recovered in rates for domestic, small commercial, and traffic control customers at secondary service level. CAL-SLA first argued that this relay equipment is used in traffic control systems and is not part of Edison's streetlighting system. However, Edison has shown in rebuttal testimony that the relay equipment in question is solely related to the streetlighting system. Since photo-controllers are not rated to safely handle loads over 1,000 watts, auxiliary relays are required to open and close the streetlight circuit at traffic-controlled intersections because streetlight loads at these intersections typically exceed 1,000 watts. A traffic control system does not require an auxiliary relay.

Now, CAL-SLA argues that Edison has not proved that the relays are not customer-owned. Relying on Edison's Electrical

Service Requirements Manual (p. 411),[51] which requires that "on underground installations exceeding 120 volts, the customer shall provide the auxiliary relay," CAL-SLA argues that the relays are customer-owned. However, as Edison points out, the sentence preceeding the passage relied upon by CAL-SLA states that:

> "The Company will provide and install 120 volt relays."

Edison has established that almost all LS-2 service is provided at 120 volts. Only a few LS-2 lights owned by CalTrans (less than 100) are served at higher voltage. By comparison, Edison expects to serve 141,267 streetlights under Schedule LS-2 in 1992. Thus, if anything, page 411 of the Electric Service Requirements Manual shows that relays are company-owned.

In its opening brief, CAL-SLA also relies on Special Condition 3 of Schedule LS-2, which states:

> "Switching and Related Facilities: For all Night and Midnight Service under the Company's standard operating schedules, the Company will furnish, operate, and maintain the necessary switching facilities. All auxiliary relay equipment, irrespective of voltage, not furnished by the Company, but required in connection with providing streetlighting service, shall be furnished, installed, and maintained by the customer in accordance with the Company's requirements."

We find this language to be unenlightening for the issue at hand. Its obvious purpose is to require that those relays which are not furnished by the company be furnished by the customer and installed and maintained under company specifications. It implies that auxiliary relays are sometimes company-owned and some times owned

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51 This manual is an "in house" Edison document basically consisting of instructions to Edison's field personnel.

by customers. It does not indicate the circumstances under which a customer might own the relay.

We are left with the testimony of Edison's witness to decide this issue. CAL-SLA argues that we should not do so because he relied on other Edison personnel, rather than personal knowledge. Presumably, CAL-SLA would require several witnesses, perhaps including bookkeepers, accounts payable clerks, customer service personnel, electricians, foremen, etc., to establish that Edison has paid for and installed auxiliary relays to service LS-2 customers. We reject such a notion. It is necessary for rate design witnesses to rely on others in order to allow efficient administration of GRC hearings. Edison has established through the testimony of its expert rate design witness that Edison owns and installs relay equipment, the cost of which should be reflected in facilities charges for LS-2 customers.

7.7.1.2 Aluminum Conductor

CAL-SLA argues that a proposed charge for aluminum conductor for LS-2 multiple customers is based on double counting, since cable is identified as a component of marginal cost. However, the cable included in the customer charge is a service drop from the transformer to an auxiliary relay or compression splice. The conductor for which a separate facilities charge is proposed is used to connect the auxiliary relay to the customer's service point. Thus, there is no "double counting" of cables. Rather, two cables are properly counted. Edison has shown that this addition to the LS-2 facilities charge is appropriate.

7.7.1.3 Future Studies

CAL-SLA recommends that for the next GRC, Edison analyze freezing the total facilities charges for Schedule LS-1 and recouping any difference between the actual installation costs and the facilities allowance from applicants requesting new streetlights. Also, CAL-SLA urges Edison to work with local governments that own streetlights on series circuits to develop a replacement program if economically feasible and of financial interest to both local governments and Edison. Edison's rate proposal for LS-2 series circuits suggests a need to study their replacement.

These uncontested requests are reasonable. We will direct Edison to include as part of its next GRC filing an analysis of whether LS-1 charges should be frozen. Edison should also evaluate and report on options for replacing series circuits. We encourage Edison to work with its SL customers in doing so.

7.7.2 Rate Design

Edison and CAL-SLA agree that the increase to facilities and other nonenergy-related costs for Schedules LS-2 and LS-3 should be limited to 10% per year. The resulting deficiency should be collected from all streetlighting schedules including Schedules LS-2 and LS-3.

DRA generally does not object to Edison's proposals for SL rate design, but it proposes a 5% per year limit on the increase with the resulting deficiency allocated only to Schedule LS-1 customers. Edison believes this proposal is unfair to Schedule LS-1 customers as it will require a substantial number of years before Schedule LS-2 and LS-3 customers pay their fair share of facilities costs. DRA acknowledged that its proposal was the result of DRA's different revenue requirement forecasts and other practical concerns, and not the result of policy differences. We adopt Edison's 10% proposal.

CAL-SLA recommends that the energy charges be reduced in future proceedings as the nonenergy charges increase. As noted by Edison, this will automatically occur through the normal rate design process. Once a total revenue requirement for the SL Group is established, any additional revenue collected through nonenergy charges will result in less revenue being collected through energy charges.

7.7.3 Response Time Standards

Noting the important public purposes of streetlights, CAL-SLA proposes the following two tariff conditions:

1. Edison shall install a streetlight on an existing distribution pole within 30 days after a local public agency has made the request for installation.

2. Edison shall maintain all company-owned or maintained streetlights such that all outages are repaired within seven days.

CAL-SLA believes that Edison's installation and maintenance periods are not satisfactory. CAL-SLA states that in the City of Santa Barbara, it takes an average of 60 days and 90 days for Edison to install a new light for service under Schedule LS-2 and LS-1 respectively. CAL-SLA also states that on average it takes 21 days to repair outages in Santa Barbara. Edison responds that the 60 and 90-day installation periods referenced by CAL-SLA include lead time on new orders. Delays are often attributable to the customer or developer. Edison states that it has a contractual requirement with its streetlighting contractors to complete all installations within 30 days after Edison releases a work order. Edison releases a work order only when site preparation allows installation. We conclude that sufficient need for tariff standards for installation times has not been demonstrated, and therefore will not adopt any.

Regarding maintenance standards, Edison showed that it responded to 91,187 streetlight maintenance calls from October 1, 1989 to October 26, 1991. The average response time was 2.8 days on a system-wide basis. The average response time was 4.4 days within the City of Santa Barbara for 263 calls during a similar period.

We note that Edison provided data on average maintenance response time but not the maximum time or the typical range of times. Nevertheless, it is apparent that at least on an overall basis, Edison is responding reasonably. Unfortunately, we do not know enough to determine the full nature and extent of any problems that may exist. Moreover, we lack clear data in this record which might support any particular standard. Simply adopting a seven-day standard might impose an unreasonable burden on Edison if there are occasionally valid reasons (such as emergencies) why it cannot be met. On the other hand, a standard such as requiring seven-day response 90% of the time would be of little value to an individual customer, and therefore would not be a likely candidate for a tariff rule.

We conclude that the need for and propriety of a binding tariff rule for maintenance response time has not been demonstrated in this proceeding. We are not content to leave the issue at that, however. We are sensitive to the important public safety functions served by streetlight agencies. Long response times are not acceptable from a public policy standpoint. While there appears to be no systemic problem on the Edison system, we wish to ensure that the response times continue to be reasonable and are improved if necessary. Accordingly, we will require Edison to conduct a more complete analysis of maintenance response times for presentation in its next GRC. As part of that presentation, Edison should address whether workable tariff provisons to better ensure timely responses are appropriate.

7.8 Interruptible Rate Schedules

7.8.1 Introduction

Edison has an interruptible rate program under which LP and Ag & Pumping customers who agree to make their peak-hour loads subject to curtailment on short notice are provided with a reduced rate. The interruptible tariffs give Edison the option of interrupting these customer loads under specified criteria. Approximately 960 MW of Edison's customer load can be signaled for interruption. The rate reduction, or interruptible credit, is set to reflect the cost of peak capacity (coincident capacity cost) which the utility avoids by not having to make facilities available to serve the interruptible load.

All parties who presented testimony on these program issues used the same general "top down" approach for setting interruptible rates. That is, they treat the interruptible customers and load as if they were firm (i.e. not interruptible) for rate design purposes then subtract the credit in the design of interruptible rates. It is also termed a supply-side approach because the interruptible load is in many ways equivalent to a peaking capacity resource. DRA agrees with Edison that the "supply side" approach is the most appropriate method to develop credits for interruptible customers since that method focuses on the costs avoided by the interruptible program.

CMA, however, discussed an alternative demand-side framework in its opening and closing briefs. Under this framework, rates for interruptible schedules would be calculated on EPMC principles just as they are for other schedules. CMA claims this alternative approach would avoid some of the difficult theoretical and methodological issues that attend the more traditional supply-side approach.

While the CMA alternative is an intriguing one, there is little foundation in this record on which to consider it further or on which to implement it. Moreover, as Edison's testimony demonstrates, there are difficult issues with this approach as well as with the supply-side approach. If the interruptible rates were to be calculated on an EPMC basis without assignment of coincident capacity costs, the result would be equivalent to a credit which exceeds the cost avoided by the program. It would be cheaper for the utility to obtain the resource at marginal cost than to pay credits above marginal cost for the same capacity.

We will adopt the continued use of the supply-side approach since it provides the interruptible customers with a credit equivalent to the costs avoided by the interruptible program. Accordingly, in establishing the credit level, we determine the costs avoided by Edison of having such a load available for curtailment.

In the following subsections we address issues that pertain to the calculation of the credit, issues of rate design, and various proposals to modify the interruptible program.

7.8.2 Credit Levels

Edison presented a calculation of the credit at $93.96/kW-year at the generation level. DRA presented a similar calculation of $96.74 kW-year. The comparable existing credits for the majority of interruptible customers vary from $130/kW-year to $184/kW-year. TURN's basic proposal is a credit of $24.48/kW-year as part of its proposal for a "pay for performance" option; otherwise TURN proposes a credit of $61.02/kW-year. CLECA, CMA, FEA, and IU (the interruptible customers) support higher values. For example, FEA proposes a transmission level credit of $127.85/kW-year. Edison's and DRA's comparable values are $96.90/kW-year and $99.76/kW-year respectively. The differences in these values are due to the parties' different positions on T&D costs, an ERI adjustment, and a reserve margin adjustment.

7.8.2.1 T&D Cost

There is little controversy that the marginal generation capacity cost should be included in the calculation of the credit. Except for TURN, the parties agree that a major portion of marginal transmission capacity costs and a portion of the distribution system capacity costs are avoided as well.

Edison initially allocated 100% of marginal transmission cost to coincident demand and 0% of marginal distribution costs to coincident demand. DRA proposed an allocation based on coincident demand factors of approximately 92% and 33% respectively. These are the same factors used by DRA, and which we are adopting in today's decision, for revenue allocation purposes. Edison and the interruptible customers accept DRA's proposal.

TURN, on the other hand, claims that T&D costs are not avoided by the interruptible program. TURN states that this is because Edison will experience bulk transmission problems if it actually calls for interruptions and because Edison will call for interruptions based on generation system conditions but not on transmission-related events. We find insufficient support for these factual assertions.

TURN goes on to argue that there is no substantive evidence to support the proposition that Edison's interruptible program avoids any T&D costs. According to TURN, no party has pointed to any specific T&D investment which has been avoided. Thus, TURN does not accept the testimony of Edison, DRA, and the interruptible customers that T&D system planners take the interruptible load into account. We agree with DRA and the other parties who point out that TURN's position is equivalent to requiring proof of a negative proposition. The witnesses were not able to identify specific projects precisely because they were not planned. We find that there is a planning benefit in the interruptible program which extends to the T&D system as well as the generation system.

Finally, TURN argues that the connection between generation and T&D costs is weak, and, therefore, avoiding generation does not automatically avoid all coincident T&D costs. TURN states that large volumes of T&D investments are necessary even when generation capacity is not needed. Moreover, TURN asserts, generation plant is built even when generation capacity is not needed. But TURN does not acknowledge that it is the customers who actually impose coincident demands who should pay for these coincident T&D costs. The issue is not, as TURN implies, whether industrial customers should pay for load growth; rather, it is whether customers who have agreed to have their loads interrupted should pay for coincident T&D costs.

As Edison argues, one kW of capacity at the load source resulting from interruption is more valuable to the utility than one kW generated in a power plant somewhere inside of or outside the service territory. We conclude that the interruptible program avoids coincident T&D costs, and that the credit should reflect this fact. In doing so we recognize that we recently declined to include distribution costs in calculating the interruptible incentive for Pacific Gas and Electric Company based on a lack of factual support. (D.92-05-031, p. 14.) The record in this proceeding persuades us that inclusion of the coincident portion of Edison's distribution costs is appropriate for the Edison system.

7.8.2.2 ERI Adjustment

Edison and DRA believe that the ERI-adjusted annualized cost of a combustion turbine is the most appropriate measure of the marginal generation cost. DRA agrees with Edison that a six-year average ERI figure should be used to adjust the marginal generation cost. Edison believes the adjustment is appropriate because when the system has excess capacity and the ERI is less than 1.0, a utility will not build additional combustion turbines. Under these conditions the value of interruptible load is less than the full cost of a combustion turbine. DRA argues similarly that the ERI adjustment is necessary to ensure that the credit is cost-based. TURN prefers its "pay for performance" approach because it would avoid the ERI issue, but agrees with Edison and DRA that if the cost of a combustion turbine is used there should be an ERI adjustment.

CLECA recognizes that in recent cases the Commission has generally used an ERI multiplier to adjust the cost of avoided generation capacity. However, CLECA believes there are valid reasons for not making an ERI adjustment. According to CLECA, an ERI of 1.0 signals to customers that the interruptible program is viewed by the Commission and the utility as a long-term one. CLECA also believes that an ERI of 1.0 would signal a desire to offer stable incentive levels.

FEA and IU take a stronger view, arguing that an ERI adjustment is not appropriate. CMA agrees, calling the ERI irrelevant. FEA emphasizes the long-term savings of the program. FEA contends that in the long run, the value should equal the full cost of a combustion turbine. FEA also asserts there is a need for stability in the credits. Finally FEA argues that with an ERI of less than 1.0, interruptible customers pay for capacity which is not meant to serve them. IU similarly emphasizes the need to reflect the cost savings of a system in long-run equilibrium and the need for stability in the incentive. IU also notes that the ERI calculations used by DRA to develop its six-year average reach 1.0 in 1994 without interruptible load and 1.0 in 1996 with interruptible load. Thus, IU claims, the ERI is no longer appropriate because it reflects a past problem of excess capacity that will no longer exist.

We conclude that for calculating the interruptible credit, the appropriate measure of avoided generating capacity cost should be the cost of a combustion turbine adjusted by a six-year average ERI, as proposed by Edison and DRA. The arguments of the interruptible customers emphasize a long-term view which gives too little weight to the current excess capacity situation. Given that situation, we are persuaded that the best measure of avoided cost of generation capacity is less than the full marginal cost of a combustion turbine. We reject the contention that an ERI of less than 1.0 requires interruptible customers to pay for capacity which is not meant to serve them. We are simply allowing a credit which reflects our best estimate of the avoided cost, and no more.

We agree with the interruptible customers that program stability is important, but not at the expense of setting a credit level which is significantly in excess of the avoided cost. Program stability does not require that credit be set without regard to changes in Edison's capacity situation. DRA reminds us that use of a six-year average will remove much of the volatility in ERI values. We believe that the six-year average will yield a reasonable balance between the need for stability and a cost-based credit. Further, it will result in appropriate signals about the value of the program during current and future years.

The actual calculation of a six-year average ERI is not contested. Edison has agreed with DRA's calculation of an ERI value of 0.62. DRA, in turn, agrees with CLECA that the calculation should reflect the adoption of a floor ERI of 0.1 in D.91-11-057. Thus, all parties agree on CLECA's calculation of a six-year average of 0.653. We will adopt this value. It reflects agreement that the ERI used for the interruptible credit should be the average of the "interruptible in/out" calculations, and based on the "barebones" resource plan with exclusion of uncommitted Demand-Side Management load.

The interruptible customers have expressed a preference for stability in the credit level. We note that an additional degree of stability can be achieved by adopting Edison's proposal to use the ERI adopted today in proceedings between the GRCs. As noted by Edison in comments on the proposed decision, its proposal is unopposed. We will therefore adopt it.

7.8.2.3 CRR Adjustment

FEA and IU propose that the avoided generation cost be adjusted upward by the CRR to reflect the reserve margin on Edison's system. CLECA supports this proposal. According to FEA, this adjustment is necessary to reflect the full cost of avoided generation capacity. FEA explains that when Edison builds capacity to serve a load of 1,000 kW, it must build an extra 15%, or a total of 1,150 kW of capacity. When Edison does not have to build capacity to serve the interruptible load, it also does not have to build the increment for reserve margin. From this FEA concludes that the marginal cost of generation should be grossed up by 15%.

Edison believes the adjustment is inappropriate for two reasons. First, interruptible load is available only 150 hours per year, whereas a combustion turbine is available year round. Second, when the ERI is less than 1.0 and the system has excess capacity, interruptible load does not avoid the construction of 115% of interruptible load since the utility can rely on its excess capacity to satisfy reserve requirements.

We do not find Edison's first argument to be persuasive. Edison has not shown that the fact that interruptible load is available for a limited amount of time affects the reserve margin. If anything, Edison's argument suggests a possible need for a downward adjustment to reflect the possibility that the combustion turbine is a superior resource and therefore more valuable on a kW-for-kW basis because of its year-round availability. It would seem that if the utility has a choice of paying a dollar for a given amount of interruptible load or a dollar for the same amount of combustion turbine capacity, its choice would be the latter. However, we do not believe that the appropriate way to make such an adjustment (if indeed it is a valid one) is to not make an upward CRR adjustment that may be otherwise appropriate. We will leave this matter for future proceedings.

Edison's second argument is a compelling one, however. In years when there is significant excess capacity, as indicated by the six-year average "interruptible in/out" ERI of 0.653 that we are adopting in this decision for calculating the credit, Edison can rely on its existing capacity to satisfy reserve requirements.

<u>7.8.2.4 Adopted Credit</u>

FEA asks that in setting the credit level we consider the current state of the interruptible program. In the past the interruptible discounts of $130/kW-year to $184/kW-year have allowed Edison to contract for nearly 1,000 MW of interruptible load. FEA states that setting the credit too low will cause interruptible load to either become firm or leave the system. The proper response to this concern is to set the interruptible credit levels at the avoided cost of peak-capacity resources. That is what we have endeavored to do. Edison should not pay a credit in excess of its avoided cost because it would be better off acquiring its own resources over which it would have greater control. Conversely, Edison should not pay less than avoided cost for the reasons cited by FEA.

Applying the adopted principles, the level of incentive in $/kW-year at the generation level is calculated as follows:

Avoided Cost of Generation	$82.15 x 0.6530 =	$53.64
Avoided Cost of Transmission	$32.70 x 0.9235 =	$30.20
Avoided Cost of Distribution	$49.82 x 0.3317 =	$16.53
Total		$100.37

With the adjustments for losses, the levels of incentive at the subtransmission, primary, and secondary voltage levels after adjusting for line losses are $86.44/kW-year, $108.13/kW-year, and $117.57/kW-year, respectively.

<u>7.8.3 Interruptible Schedule Rate Design</u>

<u>7.8.3.1 Schedule I-6</u>

Edison proposes to design rates for Schedule I-6 by allocating the annual $/kW credit to various pricing periods on an LOLP basis and providing the credits in demand and energy charges based on the relationship of these charges to their EPMC levels. For example, if the summer on-peak demand charge is at 50% of its EPMC level, Edison uses 50% of the avoided coincident capacity cost in that period as a credit to the summer on-peak demand charge.

CLECA proposes two alternative rate designs. CLECA prefers to assign credits in a way that moves the recovery of coincident demand costs to their LOLP-based time periods. Under its Option 1, CLECA allocates capacity costs on an LOLP basis to various pricing periods. Thus, 83% of the coincident capacity cost is assigned to the summer on-peak period. Within time periods, the credit is assigned to demand and energy charges on the basis of the ratio of revenues collected in these charges in the firm service rates. CLECA states that this option would essentially result in a 100% LOLP-capacity cost allocation to time periods.

Under CLECA's Option 2, the total amount of credit is assigned to TOU periods according to the allocation of LOLP to those periods. For example, if 60% of the coincident capacity cost is recovered in the on-peak period, 60% of the interruptible credit would be applied to the on-peak period. This credit is then apportioned to time-related demand charges and energy charges on the basis of the relative revenue recovered from those two charges.

Edison criticizes CLECA's Option 1 because demand and energy charges in each period do not recover full LOLP-based coincident capacity costs. Edison argues that Option 1 has the same characteristic for which CLECA criticizes Edison's proposal. Edison states that its proposal differs from Option 2 mainly due to the issue of inclusion of uncollected coincident capacity costs in the ratio of marginal energy costs. Edison further points out that CLECA's criticism that Edison allocates the credits largely to the summer on-peak period is incorrect, since it only assigns the credit to energy and demand charges on a relative EPMC basis. Thus, according to Edison, its method accounts for any coincident capacity costs that are recovered in periods other than summer on-peak.

CLECA's principal criticism of Edison's approach appears to be that it results in excess recovery of coincident capacity costs in off-peak energy charges. In response, Edison points out that its proposal is made in conjunction with its proposal to set TOU energy charges based on marginal energy-cost ratios. Edison states that if the Commission adopts the inclusion of uncollected coincident capacity costs in the marginal energy cost ratios, its I-6 rate design can be simply revised to allocate the remaining interruptible credit to energy charges based on these newly defined ratios.

We will adopt Edison's proposal. For consistency with our decision to include coincident capacity costs in the marginal energy cost ratios used to set on- and mid-peak energy charges, we also adopt the modification suggested by Edison. With this change CLECA's major concern should be resolved. Moreover, the resulting rate design will be similar to that resulting under Option 2.

7.8.3.2 Schedule TOU-8-I

Currently, the majority of Edison's interruptible customers are served under Schedules I-3 and I-5. They receive the credit on a flat cents/kWh basis. These schedules are scheduled for cancellation. Since the interruptible credit is being reduced by as much as 50%, Edison is concerned about rate impacts on customers as they move to schedules such as Schedule I-6. Edison proposes a new optional Schedule TOU-8-I for rate stability purposes. This schedule would provide the interruptible credit on a flat cents/kWh basis.

DRA opposes the establishment of this schedule because of its flat-rate credit. DRA notes that by offering such a schedule, Edison is eliminating the pricing signals sent when the credit is allocated to different rate components and pricing periods. According to DRA, these are exactly the types of pricing signals which the Commission has endeavored to implement over the past decade.

Moreover, DRA notes, the nature of the credits under the proposed tariff are such that customers do not need to have any interruptible load in peak hours. A customer could have the majority of his load in off-peak hours and obtain a sizable credit. DRA concludes that the proposal represents a step back in rate design policy and should be rejected.

DRA acknowledges Edison's rate stability concerns, but notes that the I-3 and I-5 customers targeted by this proposed schedule have been on notice since Edison's last GRC that the schedules would be terminated. Finally, both DRA and Edison have proposed bill limiters in response to these stability concerns.

We will reject Edison's proposal to establish this option for the reasons discussed by DRA.

7.8.3.3 Bill Limiters

Edison proposes a limiter for its interruptible rate schedules to mitigate the bill impact that could occur for some interruptible customers who will move from tariffs which will be eliminated in 1992 and 1993. Edison proposes to limit the monthly bill increase of any customer to 10% and 20% above the average revenue change for the applicable rate group in 1993 and 1994 respectively, compared to rates effective in December, 1992. CLECA generally concurs with Edison's proposal. TURN does not support any limiter.

DRA generally supports the concept of bill limiters to mitigate significant rate shock, but it proposes larger limits of 20% and 40% and a somewhat different concept. DRA seeks to ensure that the I-6 rates are fully effective (i.e. not limited) by 1995. DRA asserts that by comparison Edison's is an open-ended bill limiter with no clear timetable for removal. DRA also believes provision should be made for the possibility of a reduction in rates. With a reduction, the bill limiter could become smaller than the 10% and 20% proposed by Edison. DRA proposes that in no instance should the bill limiter be less than 20% in 1993 and 40% in 1994.

Both Edison and DRA have cited good reasons to adopt their respective proposals. As DRA notes, customers targeted by these limiters have been on notice since 1988 that interruptible schedules on which they take service would be eliminated, and it's now clear that the credits have not been cost-based. On the other hand, these customers could have had no way of knowing that significant reductions in the credit levels would be adopted in this proceeding. We believe that a limiter which is intermediate to the proposals represents a reasonable compromise. Accordingly, we will adopt limiters using the mechanism proposed by Edison but with percentage increases of 15% and 30% for 1993 and 1994 respectively. We do not find it necessary to address other eventualities as proposed by DRA. As Edison notes, the maximum bill increase that results from reduction of the credit is 25%. We address a DRA proposal for restricting the application of limiters in the next subsection.

7.8.4 Other Interruptible Program Issues

7.8.4.1 Interruptible Bidding

DRA expects that in the near future the Commission will institute Demand-Side Management Bidding programs which will be applicable to current interruptible customers. DRA believes the Commission should have an opportunity to institute such programs by taking steps to ensure that there will be a pool of interruptible customers to participate. DRA is concerned that significant participation by Edison customers could be thwarted by Edison's proposal to continue the existing interruptible contract length of five years.

DRA proposes that two mechanisms be adopted to assist the transition to interruptible bidding. First, DRA recommends the addition of language in the proposed I-6 and TOU-8-SOP-1 tariffs which would provide that Edison has the right to terminate contracts on one year's notice, providing that the customer clearly has the option of participating in a Demand-Side Management Bidding Program. Second, DRA proposes that customers have a choice to avoid the risk of being involved in bidding programs, in return for which they would relinquish the protection of the bill-limiter protection that would otherwise apply as they move from I-3 and I-5 tariffs to I-6 and TOU-8-SOP-I. The sunset for this provision would be September 30, 1992, thereby providing existing I-3 and I-5 customers with about three months after this decision to decide between these options.

DRA is putting the cart before the horse. In the Phase 1 decision of this GRC we determined that while the setting of interruptible rates belongs in this Phase 2, the current Demand-Side Management Rulemaking proceeding (Rulemaking (R.) 91-08-003) is the proper forum for consideration of the concept of interruptible bidding because policy choices will affect all utilities.[52] The parties have pointed out that the subject of interruptible bidding has not yet been addressed in that rulemaking. Thus, DRA's proposal is based on an assumption that has not yet been realized. We prefer to consider any transitional issues that may be associated with interruptible bidding in conjunction with the overall merits of such a program, when and in the same proceeding where the subject arises.

Edison has shown that tariff language changes are not necessary to create a pool of available customers because the Commission already has the authority to terminate or modify existing interruptible contracts. More importantly, as Edison and several parties have noted, requiring customers to make a commitment to either risk the uncertainty of an unknown program or relinquish bill impact protection which we have found to be appropriate is not a fair choice for the Commission to impose. We agree that it is highly unlikely that the choice could be an informed one if it must be made on or before September 30, 1992.

7.8.4.2 Criteria for Interruptions

Edison proposes to revise the criteria it uses to determine when it will call for interruptions. Interruptions would be called when the next to the last peaker (a generation unit designed and operated primarily to meet peak load) is required to be operated and there is insufficient time available to evaluate and secure alternative options; or when spinning reserve is

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52 D.91-12-076, pp. 134-135

anticipated to fall below 5% for more than one hour and Edison cannot purchase energy and capacity at a price below 7¢/kWh. Edison also proposes to delete all tariff language which provides for interruptions when "in the judgement of the Company, a shortage of supply exists." CLECA agrees that these are reasonable changes. ACWA is concerned that the proposal is a significant revision which is not supported by definitive data.

DRA also agrees with Edison's proposal, but believes that it should go farther. DRA notes that these are primarily operational criteria. DRA believes that while they are helpful in providing guidance regarding the circumstances when interruptions will be most likely, they need to be set in the context of an overall economic criterion. According to DRA, interruptible customers are a resource which Edison can manage in an economically optimal fashion like any other resource. DRA believes that when it is economical to interrupt these customers they should in fact be interrupted regardless of system operating conditions. DRA suggests a criterion such as interrupting "when in the judgement of the Company it is more cost-effective to interrupt than to serve."

DRA believes this economic criterion is unlikely to be used lightly by Edison, since interrupting customers results in lost revenues and since Edison would have to demonstrate to the Commission that the cost of purchasing capacity and energy exceeded the value of the lost revenues from the interruption. In connection with this latter observation, DRA recommends that Edison keep narrative records on actions related to decisions regarding the interruptible program.

Edison, ACWA, CLECA, and FEA oppose DRA's proposed economic criterion. Edison notes that the proposed level of interruptible credit is based on the avoidance of costs by the interruptible load in the planning process, and is thus based on the current nature of the program as a source of capacity in system emergency conditions. According to Edison, broadening the criteria to include nonemergency conditions may require incorporation of additional credits. Further, it would place additional burdens on system operators. CLECA also emphasizes the current nature of the program as an emergency program. CLECA is concerned that the utility would not have time to make judgments regarding economics before acting. CLECA notes that an economic interruption is unlikely during the current GRC cycle, and suggests that the option be deferred for review in the next GRC. FEA largely agrees with the criticisms of Edison and CLECA, noting, for example, that the proposal needs more specificity and a more thorough evaluation.

We believe DRA's proposal may be meritorious in concept but that it is not ready for implementation. For one thing, we agree that there should be more specificity in the criterion. Edison has proposed to replace tariff language which refers to company judgment with more specific operational conditions that would trigger a call for interruptions. We think that is an appropriate step that provides more information to all parties about how the program works. DRA's suggestion for implementing its proposal would revert to such language for economic conditions. While DRA's proposal to take a broader view of the value of an interruptible program is probably an important positive step to take, it should be taken in conjunction with the calculation of the credit. DRA defends its proposal as just an extension of Edison's, noting that the 7¢/kWh criterion is in fact an economic one. We find the difference to be a significant one because of the degree of judgment involved.

DRA states that its purpose in making the proposal for an economic criterion is to have Edison enlarge its own view of the program, so that Edison sees interruptible load as another resource. It is not clear to us that Edison lacks such a perspective. However, we will direct Edison to include in its next GRC filing an analysis of whether broadened interruption criteria should be adopted in that proceeding.

Returning to Edison's proposed revisions to the criteria for interrupting, we note that all parties but ACWA support the proposals. ACWA seems to be largely concerned with the 7¢/kWh criterion. As Edison explains, it is based on a recognition that when a shortage of supply exists on Edison's system, it may be possible to remedy the situation with cost-effective purchases of capacity and energy. Edison has shown that 7¢/kWh is a reasonable trigger to use for this purpose. We will approve Edison's revised criteria.

7.8.4.3 TURN's Pay for Performance Proposal

TURN presented a "pay for performance" proposal for interruptible credits. The interruptible schedules would provide a floor credit of 40% of the cost of a combustion turbine for customers who agree to two audit curtailments per year, and 30% of the cost of a combustion turbine for those who do not agree to audit curtailments. Customers who agree to audit curtailments would be entitled to additional credits equal to 10% of the cost of a combustion turbine for every curtailment beyond the two audit curtailments. Those who do not agree to audit curtailments would receive additional credits of 5% of the combustion turbine cost for the first two curtailments and then 10% for additional curtailments.

TURN believes audit curtailment are necessary to test the willingness and ability of customers to actually reduce load when called upon by the utility to do so. TURN equates such tests with tests of peaking generating equipment.

TURN states that it offered the proposal because it is aware of controversy regarding the amount of costs avoided by the program. TURN believes that its proposal would avoid "arguing at great length about the ERI" by recognizing the proposition that a year with more interruptions has a lower level of reliability, and a higher avoided cost, than a year with fewer interruptions. If its primary "pay for performance" proposal is not adopted, TURN recommends that the interruptible credit be reduced by 10% for customers who do not agree to audit curtailments.

Edison, DRA, and the interruptible customers oppose TURN's proposals. They generally argue as follows. First, it is based on an incorrect assumption. The main value of the interruptible program is in the availability of load as a long-term planning resource. Thus, the value does not vary with specific instances of operation of the program. Second, the volatility in the credit level that would result would discourage participation in the program. Third, the proposed credit levels greatly undervalue the interruptible load, with a potentially devastating effect on the program. Fourth, the need to avoid ERI arguments is not as obvious as TURN suggests, as evidenced by general agreement on its actual calculation in this very proceeding. Even the more difficult conceptual issues of applying the ERI did not engender the degree of controversy in this proceeding that TURN's pay for performance proposal did. Fifth, TURN's proposal results in a perverse incentive for system dispatchers because with each interruption, Edison would have to pay out \$4/kW-year to \$8/kW-year. Thus, each interruption would require Edison to pay out \$4 to \$8 million. Sixth, audit curtailments are undesirable because they affect all customers, not just those who enrolled in the program with the expectation of not being interrupted; and unnecessary because Edison has proposed a more effective enforcement program consisting of high penalties for noncompliance. Seventh, the need for testing equipment is not analogous to "testing" customers. Edison's proposal provides that a customer who fails to respond to two calls for interruption loses the credit for an entire year. There is no comparable treatment of equipment.

The lengthy list of arguments against the proposal presents a compelling case. We reject TURN's proposal.

7.8.4.4 Allowable Interruptions

ACWA objects to a change in the number of allowed interruptions. In the last GRC the limit on the allowed number of interruptions was set at 25 for Schedule I-6. Other schedules which are scheduled for cancellation have a lower limit of 15 interruptions. As Edison has pointed out, customers were notified in Edison's last GRC that they would be moved to Schedule I-6, and have therefore been aware of this change since that time.

7.9 Mobilehome Park Issues

7.9.1 Introduction and Summary of Proposals

Edison serves 1,605 master-metered mobilehome park accounts under Schedule DMS-2. These submetered systems serve a total of 109,727 submetered spaces. Schedule DMS-2 is included in Edison's Domestic customer group, and the rates in this schedule are based on those in Schedule D, Edison's basic residential rate schedule. Mobilehome park owners who are Edison's DMS-2 customers bill their submetered tenants at the Schedule D rates and receive a "DMS-2 Discount." Just as we addressed interruptible program issues in a separate section of this decision, we address Schedule DMS-2 issues separately due to the unique circumstances of that schedule.[53] Among other things, the Commission and the utilities it regulates are constrained in the way that rate structures are established for master-meter customers by PU Code § 739.5. That statute provides in relevant part:

> "739.5. (a) The commission shall require that, whenever gas or electric service, or both, is provided by a master-meter customer to users who are tenants of a mobilehome park, apartment

53 There are no contested issues concerning the setting of rate structures for two other master-meter schedules, Schedule DM and Schedule DMS-1. A proposal to establish Schedule DMS-3 for qualifying RV parks is addressed elsewhere in this decision.

> building, or similar residential complex, the master-meter customer shall charge each user of the service at the same rate which would be applicable if the user were receiving gas or electricity, or both, directly from the gas or electrical corporation. The commission shall require the corporation furnishing service to the master-meter customer to establish uniform rates for master-meter service at a level which will provide a sufficient differential to cover the reasonable average costs to master-meter customers of providing submeter service, except that these costs shall not exceed the average cost that the corporation would have incurred in providing comparable services directly to the user of the service."

As in past proceedings, the proper level of the cost differential required by § 739.5 is at issue here. In addition to issues involving calculation of the DMS-2 discount, including a new line loss factor and the appropriate diversity factor to reflect differences in baseline allowances and usage at the master-meter and submeter levels, the contested issues include proposals by WMA for an attrition adjustment and an alternative to the rates in Schedule D. Also at issue are proposals by Edison to continue the Base Rate Energy Charge (BREC) provision and establish a new Minimum Average Rate (MAR) provision.

Under Schedule DMS-2, master meter customers pay the rates applicable under Schedule D, Edison's basic residential rate schedule, and receive a baseline allowance and a "DMS-2 Discount" for each occupied submetered mobilehome space. The DMS-2 Discount is currently $0.21 per space per day.[54] The discount consists of a "submeter discount" based on the cost of service of $0.26, reduced by a diversity factor adjustment of $0.05. The $0.21

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54 Schedule DMS-2 provides the discount on a per space per day basis. For convenience, we omit the unit of measurement designation throughout this discussion.

discount is subject to a limiter provision which states that the total daily DMS-2 Discount shall not exceed the BREC which would have resulted under the Domestic Schedule.

Edison proposes to reduce the current cost of service discount from $0.26 to $0.18, add a new line loss adjustment of $0.03, and to reduce the diversity adjustment from $0.05 to $0.04. The total master meter adjustment would be reduced from the current level of $0.21 to $0.17.

WMA presents three alternative proposals for the discount. Alternative 1 provides a cost of service discount of $0.26, a diversity adjustment of of $0.01, and a loss adjustment of $0.08, for a total discount of $0.33. WMA Alternative 2 uses the cost of service and loss adjustment factors recommended by Edison and a diversity adjustment of $0.01 for a total discount of $0.20. Alternative 2 would apply in connection with a new rate which would be lower than the Schedule D rate. Alternative 3 provides a cost of service discount of $0.51 and a diversity adjustment of $0.01 for a total discount of $0.50.

The cost differential required by PU Code § 739.5(a) requires, in the first instance, an amount sufficient to cover the reasonable average costs that master meter customers actually incur by providing submetered service to individual users. WMA provided a new study of this cost, based on a study of spaces in 12 parks served by Schedule DMS-2. This study shows that the average cost incurred by DMS-2 customers is $0.82 exclusive of line losses and diversity. WMA also updated a 1979 study and arrived at an estimate of $0.36 exclusive of line losses and diversity. WMA states that these costs are substantially higher than the Edison proposal and its own proposals for the discount.[55] We agree with Edison that there are methodological problems with WMA's studies of the average costs incurred by park operators. We give little weight to an estimate as high as $0.82, particularly since WMA's alternative estimate is a significantly lower figure of $0.36 and the disparity between these estimates is not reconciled. In any event, the cost differential required by PU Code § 739.5(a) cannot exceed the cost that would be incurred by the utility in serving the submetered users directly. Edison's proposal and all but one of WMA's three alternatives provide a cost of service discount which is less than WMA's lower estimate of $0.36 for the park operator's cost of service. As discussed below, we are rejecting WMA's cost of service estimate of $0.51. Thus, we need not consider further these estimates. For this proceeding we are required to consider only the cost that would be incurred in serving the users directly.

7.9.2 The DMS-2 Submetering Discount

7.9.2.1 Edison's 37 Park Sample

To determine the DMS-2 Discount, Edison selected a random sample of 37 mobilehome parks out of 391 parks on Edison's system where the tenants are directly served and metered by Edison. Edison used this sample to develop three components of the DMS-2 Discount: a diversity adjustment, a line loss factor, and the cost of service discount.

Edison has shown that the sample was designed and selected based on principles of statistical sampling theory, but WMA disputes Edison's assertion that it provides valid estimates of the diversity factor, line loss factor, and cost of service. Since

55 We note that WMA's Alternative 3 provides a cost of service discount of $0.51, which exceeds the lower of the two WMA estimates of the cost incurred by park operators.

much of the disagreement on the level of the DMS-2 discount turns on the validity and use of this sample, we first address the various criticisms raised by WMA.

WMA claims that the sample yields a small park bias, or overrepresentation of small parks, because Edison chose parks rather than spaces as the sampling unit. We agree with Edison that it was appropriate to develop the sample on a park basis since diversity and line losses are park-level phenomena. In Edison's last GRC we directed Edison to conduct a diversity study with the understanding that it would be "a study of individually metered mobilehome customers grouped by park."[56] Further, as Edison notes, even if spaces are selected as the sampling unit, it would still be necessary to study entire parks. If, for example, 40 spaces rather than 40 parks had been sampled, it is possible that multiple spaces from a single park would be sampled, which in turn would yield a sample with fewer than 40 parks.

Edison ensured that its sample included parks of different sizes in proportion to the population by selecting 10 samples and choosing one which closely matched the population for both park size and park age. Moreover, there can be no small park bias since Edison weighted the diversity and loss factors for each park by the number of spaces in the park. Finally, there is a low correlation between park size and the diversity factor. Even if there had been overselection of small parks, it would not bias the diversity factor.

Second, WMA believes that Edison should not have used a stratified sample. Edison states that stratification of the sample on the basis of park size and age was undertaken to to improve precision in estimates of the mean. Edison states further that in the absence of correlation between the stratifying variables and

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56 26 CPUC 2d 392, 546 (1987).

the factor being measured, a stratified sample does not result in bias in the cost of service and diversity estimates.

Edison used the 37 park sample of individually-served parks to measure diversity, line loss, and cost of service characteristics for the population of DMS-2 customers. To do so, it used a weighting process to reflect the characteristics of the DMS-2 park population. WMA asserts that Edison's weighting scheme is inappropriate. Edison counters that it found a correlation between the cost of service and the age of the park, and that the weighting process yields a better reflection of size and age characteristics of the DMS-2 population.

Finally, WMA believes that the 37 park sample should not be used because another sample of 232 parks which was used for a cost of service study in the last GRC is available. WMA criticizes Edison for abandoning this sample. WMA claims that the larger sample removes statistical and sampling problems. But as Edison points out, all but 3 of the 232 parks (and 1% of the spaces) in that sample were served by underground facilities, even though 19%[57] of the population of 391 parks (and 4% of the spaces) are served by overhead facilities. Since underground facilities are more expensive to install and maintain, Edison believes that the 232 park study resulted in overestimation of the cost of service discount. Also, Edison was able to obtain more complete cost data for the 37 park sample. If costs were not available through work orders, Edison surveyed and inventoried the parks. By contrast, Edison had simply eliminated parks when costs were not available for the 232 park sample.

We conclude that the design and use of the 37 park sample is appropriate. The earlier sample of 232 parks is less reliable

57 WMA notes that this figure should be reduced to 15% to reflect the proper count of overhead parks.

because it underrepresents parks with overhead facilities and because it includes less complete cost of service data. There is no reason to conclude that, compared to the 37 park sample, the 232 park sample better removes statistical and sampling problems.

7.9.2.2 Diversity Adjustment

DMS-2 customers receive a baseline allowance for each submetered space. Since not all submetered users consume the baseline quantity, the DMS-2 customer receives a greater baseline benefit than the total of the baseline benefits received by the users. A diversity adjustment is made to correct for this difference. As previously noted, Edison proposes an adjustment of $0.04 and WMA proposes an adjustment of $0.01.

WMA faults Edison's diversity study because Edison did not assume that energy losses on the submetered system reduce the baseline benefit. WMA's diversity study reduced the benefit by assuming that baseline kWh's are used in common areas and subject to losses.

We fail to understand WMA's position on losses. Losses and diversity are separate phenomena which should be measured and accounted for separately. Otherwise, losses could be double counted, once in the diversity study and once in the loss study. We see no reason to assume, as WMA apparently does, that baseline quantities are lost while assuming that nonbaseline quantities are not lost.

WMA believes that the diversity adjustment should be reduced to reflect common area usage within the parks. Edison agrees. Edison originally used a 5% common usage factor but has increased this to 7%. Edison notes that the difference reduces the diversity adjustment by approximately $0.001. But WMA also claims that the common area use adjustment should be a determinant of the diversity factor rather than an adjustment made after the diversity benefit is calculated. We disagree. The diversity adjustment should be based on the actual consumption of submetered users, just as Schedule DMS-2 provides that the baseline allowances received by the DMS-2 customers are based on the number of submetered users multiplied by the per-user baseline allowance without adjustment for losses or common area usage.

We conclude that Edison's diversity study is based on valid assumptions, and that WMA's alternative of assuming that baseline quantities are lost differently than nonbaseline quantities should be rejected.

7.9.2.3 Cost of Service Study

Edison estimated the cost of service discount by determining the actual costs for capital expenditures and adding O&M expenses. The estimated the cost of service for the 37 park sample is $0.22. Because the sample is taken from the population of directly served parks, Edison weighted the estimate to reflect the size and age characteristics of the population of DMS-2 parks, arriving at a cost of service estimate of $0.18. WMA's Alternative 1 estimate is $0.26, based on the currently-effective estimate from the last GRC. WMA's Alternative 3 estimate is $0.51, based on an estimate of the average cost incurred by Edison for serving all Domestic customers.

WMA finds two problems with Edison's cost of service study. First, WMA believes that Edison should have accounted for the cost of replacing facilities when they have reached the end of their book lives. Second, WMA believes that Edison's study results in double charging the DMS-2 customer for master meters and related facilities such as transformers.

WMA contends that plant costs for up to 10 of the 37 parks are understated because Edison did not incorporate higher replacement costs when facilities reach the end of their book lives. For example, WMA believes that one 85-space park which had a per-space plant cost of $103.31 should reflect a cost of $377.15 when corrected for replacement costs. WMA acknowledges that actual service lives can exceed book lives but contends that recognition of that fact is not appropriate to develop average costs. We believe WMA is mistaken. Utilities do not revise plant estimates for other ratemaking purposes until plant facilities are actually removed and replaced. We see no reason to use a different method for this study.

The other WMA criticism is the double charging issue. WMA contends that DMS-2 customers pay for master meters and related equipment through the Schedule D rates they pay. Since Edison subtracted these costs from the calculation of the cost of service discount, WMA believes it pays a second time. Again, we must reject WMA's contention. Since the DMS-2 customer pays Edison according to Schedule D and receives payments from submetered users according to Schedule D, the DMS-2 customer does not pay for the master meter facilities through payment of the Schedule D rate. It is useful to recall that the purpose of the cost of service study is to estimate the average costs that Edison would incur by serving the DMS-2 parks directly. If it were to do so, it would not incur costs for master meter facilities. Thus, Edison's subtraction of these costs from the cost of service estimate is correct.

We now turn to the alternative cost of service proposals advanced by WMA. Alternate 1 is based on the 232 park sample which we have found to be less reliable than Edison's new sample. Accordingly, we reject WMA's Alternative 1. Alternative 3 is based on Edison's average cost of providing distribution service to all domestic customers. There are extensive problems with this approach, most of which do not warrant recitation here. We note that when these problems were corrected, Edison arrived at a revised Alternative 3 cost of service estimate of $0.24, or about half of the original Alternative 3 cost of service estimate of $0.47 exclusive of line losses. But the major problem with Alternative 3 is that there is no basis for using overall domestic costs to measure costs that Edison avoids by not providing distribution services within DMS-2 parks when data from a study specifically designed to measure that cost are available.

We conclude that Edison's cost of service study is based on valid methods and that it provides the most reliable estimate of the cost of service discount.

7.9.2.4 Energy Losses

In Edison's last GRC the Commission ordered Edison to undertake, in cooperation with WMA, a study of line losses incurred by submetered parks served under Schedule DMS-2.[58] That effort is still under way, apparently due at least in part to an inability of the two parties to cooperate as the Commission had anticipated.

Since a so-called DMS-2 line loss study was not completed for this GRC, Edison independently conducted a study of line losses in directly served parks using its 37 park sample. The average line loss factor was 2.07%. By weighting this value for the size and age characteristics of the DMS-2 population, Edison obtained a line loss factor of 2.22%. By contrast, WMA proposes a loss factor of 5.22%. WMA obtained its estimate by using the 3.24% loss factor which is applicable to Edison's domestic secondary system plus 50% of the 3.96% factor which is applicable to Edison's domestic primary system.

To develop its estimate, Edison used generally accepted engineering loss formulae and applied them to field data on conductors and transformers from the 37 parks. WMA criticizes this methodology for several reasons. WMA believes that Edison failed to adequately confirm the results with a verification service study; that Edison has in effect acknowledged the shortcomings of its methodology because it uses a different methodology to measure system losses; that Edison failed to use the load factor for a typical mobilehome user, using instead the load factor for all

58 26 CPUC 2d 392, 615; Ordering Paragraph 43 (1987).

master meter accounts; and that Edison failed to account for energy theft within mobilehome park systems.

While there appear to be some problems with Edison's line loss service study, we find that they are not substantial and certainly not fatal. Faced with a choice between Edison's service study and WMA's proposal, we find the choice is clear. WMA has not presented a valid alternative estimate of losses. While the loss factors it used are applicable to Edison's domestic distribution system, they are also the factors applicable to portions of the distribution serving commercial customers. Moreover, WMA includes 50% of the loss factor on the primary distribution system even though only 5% of DMS-2 customers take service at primary voltage. Primary system losses include losses from subtransmission to distribution substations, which are not relevant to mobilehome parks.

Edison should continue with its service study of losses in DMS-2 parks, cooperatively with WMA if possible. Pending availability of those service study results, we find Edison's current loss service study to be reasonable for estimating the losses Edison would incur if it served the DMS-2 parks directly.

We are troubled, however, by Edison's assertion that it is not responsible for energy theft which occurs within DMS-2 submetered systems. While this assertion is correct, it misses the point. If Edison were to serve the parks directly it would be responsible for theft to the same extent it is now responsible for theft on other parts of the distribution system. Such theft would fall within the definition of the cost differential which the DMS-2 Discount should reflect. We are left with no basis in this record for estimating a theft factor, but, for the future, Edison should provide an estimate of the theft factor that would apply in DMS-2 parks if served directly.

7.9.2.5 Adopted DMS-2 Discount

We have found that Edison's 37 park sample provides the most reliable basis for calculating the components of the discount, and that Edison used valid assumptions and appropriate methodology for determining each component except for failure to account for any theft in mobilehome park distribution systems. We therefore will adopt Edison's proposed discount of $0.17 based on a diversity adjustment of $0.04, a cost of service discount of $0.18, and a loss factor adjustment of $0.03.

WMA notes that the reduction in the DMS-2 discount will have a negative impact on DMS-2 customers. While we recognize such impacts, and we might be inclined to consider the need for stability in this schedule, we note that we are precluded by PU Code § 739.5(a) from considering any cost differential which exceeds the cost reflected in the discount we are adopting today.

7.9.2.6 Attrition Adjustment

WMA states that Edison's cost of service service study is in error because it is based on 1992 projected costs without adjustment for 1993 and 1994 costs, yet the DMS-2 Discount will remain in effect until the next GRC. WMA believes that the costs included in Edison's cost of service service study will behave similarly to costs for which Edison is allowed an operational attrition adjustment. WMA therefore proposes an attrition adjustment of 4.21% in 1993 and 4.24% in 1994 for the cost of service discount component of the DMS-2 Discount.

Edison states that the Commission has considered and rejected an attrition mechanism for the DMS-2 discount.[59] WMA asks the Commission to reconsider this rejection, noting that GRC's are now conducted on a three-year cycle.

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59 10 CPUC 2d 155, 334; Finding of Fact 169 (1982).

We find significant problems with WMA's attrition proposal and conclude that it should be rejected. For example, WMA's attrition percentages are based on its cost of service study, which we are rejecting. Adapting Edison's attrition formula to the DMS-2 cost of service service study would require development of substantial new information not currently available.

While it is clear that WMA's attrition proposal cannot be adopted, we will not leave the matter there. It is axiomatic that costs change over time. The real question is whether use of costs projected for a single year systematically understates the costs allowed over the three-year rate case cycle. If it does, and if the understatement is significant, the result is inconsistent with PU Code § 739.5(a). The record does not allow us to answer that question, but the mere fact that Edison's costs increase by an amount sufficient for it to have an attrition adjustment mechanism suggests a similar possibility of increased costs related to the DMS-2 discount. Even though the attrition mechanism appears to be unworkable, we are not convinced other mechanisms cannot be developed. For its next GRC, Edison should address the need for such mechanisms to better ensure that PU Code § 739.5(a) requirements are met over the rate case cycle.

7.9.3 Minimum Billing Proposals

7.9.3.1 BREC Provision

As previously noted, Edison proposes to continue its BREC provision to ensure that all DMS-2 customers contribute positive base rate revenue. Edison notes that without such a provision some DMS-2 customers would provide negative base rate revenues at the expense of other customers. Edison estimates that 20 DMS-2 customers are affected by the BREC provision based on the current DMS-2 discount level. Edison estimates that less than $50,000 annual revenue is involved.

7.9.3.2 Minimum Average Rate Provision

Edison proposes to implement the new MAR provision to ensure that all customers pay at least the average cost of fuel, purchased power, and the CPUC reimbursement fee. Edison states this provision is necessary to protect other customers in the event the submetering discounts are set too high. Edison states that some DMS-2 customers have average rates which are below the MAR level. Edison estimates that 50 DMS-2 customers would be affected by the MAR provision based on the current DMS-2 discount level. Edison estimates that about $19,000 annual revenue is involved. The MAR provision would in effect set a minimum rate of 5.6¢/kWh. By comparison, Edison's large TOU-8 Subtransmission customers, which have no distribution costs assigned to them, will pay 7.1 ¢/kWh.

7.9.3.3 Discussion

We agree that minimum charge provisions such as the BREC and MAR mechanisms are appropriate to ensure that cross-subsidization does not occur or is minimized. It would not be fair to other customers, whether they are DMS-2 customers or other Domestic customers.

WMA's principal objection to these mechanisms, and the only one which requires discussion, is that they are prohibited by PU Code § 739.5(a) because they can reduce the amount of the submetering discount. According to WMA's reasoning, since the statute requires rates to be established at a level which will provide a prescribed cost differential, the DMS-2 customer must never be deprived of the full amount of that differential regardless of whether the customer imposes a negative contribution to base rate revenues or pays less than the average cost of energy. We reject this interpretation. Taking the reasoning to an extreme, we wonder if WMA would have Edison pay a DMS-2 Discount to customers who provide less revenue than the full amount of the discount. If Edison is not allowed to fashion reasonable minimum charge provisions, it seems that such a result could occur. A statutory construction which requires such a result cannot be sustained in this case. In fact, PU Code § 451 requires Edison's rates to be just and reasonable, and Edison has shown that minimum bill provisions are necessary to ensure that DMS-2 rates are just and reasonable. PU Code § 739.5(a) should be construed in harmony with and in the context of the statutory framework as a whole. (See, Steketee v. Lintz, Williams & Rothenberg (1985) 38 Cal. 3d 46, 52, 210 Cal. Rptr. 781.) We conclude that Edison's BREC provision should be continued and that the MAR provision should be implemented.

7.9.4 WMA's Alternative Rate Proposal

As noted earlier, WMA's Alternative 2 proposal provides that if the analysis underlying Edison's proposed DMS-2 Discount is adopted, it should only be applied in connection with a new rate for DMS-2 customers which would be lower than the Schedule D rate which now applies. According to WMA, if the Commission adopts a $0.21 estimate of the cost of serving submetered customers when the average domestic class cost is $0.51, it would be consistent with Commission policy to translate that discrepancy into marginal cost based rates for DMS-2 customer. WMA believes the DMS-2 rates should be reduced by about 35%, or about 4¢/kWh below the Schedule D rate.

We are not convinced of the merits of WMA's proposal. WMA used a marginal cost analysis to support its rate proposal, but the cost differential required by PU Code § 739.5(a) is based on average costs. Also, Edison discovered flaws in WMA's marginal cost analysis such as multiplying the number of DMS-2 customers by the marginal customer cost rather than the number of spaces, resulting in an underestimate of the cost to serve DMS-2 customers. Edison believes that correction of these errors leads to the conclusion that its marginal cost of directly serving tenants in submetered parks would be higher than those of the average Domestic customer.

Finally, the proposal appears to be inconsistent with the statute's requirements. Creating a separate rate group and lower rates for Schedule DMS-2 would not be possible when DMS-2 tenants pay the Schedule D rates to the DMS-2 customer and the customer in turn receives a differential base on average costs of service. We conclude that WMA's Alternative 2 cannot be adopted.

Findings of Fact

1. Phase 1 of this GRC was the forum where all parties with an interest in revenue requirement issues were expected to focus that interest.

2. The RCP makes no provision for considering revenue requirements in Phase 2 of this GRC; and Edison provided notice to the public and to its customers that the Commission had reviewed revenue changes in Phase 1 and, further, that Phase 2 would address revenue allocation and rate design.

3. Edison submitted forecasts supporting supplemental revenue requirement authorization for meters at times when the forecasts could have been litigated in Phase 1.

4. All disputed issues regarding the appropriate forecasts of customers and sales for Phase 2 purposes have been resolved.

5. The forecast of present rate revenues by rate group and rate schedule which we adopt for Phase 2 purposes is based on revenue requirement, sales, and billing determinants adopted in D.92-01-018.

6. Finding at this time that PG&E's area marginal cost service study approach is an appropriate model for service study by Edison would require that we prejudge its validity and use in the PG&E GRC.

7. Even if PG&E's area service study is found to be a reasonable basis for setting PG&E's rates, it does not necessarily follow that the service study is an appropriate model for Edison.

8. The incremental precision in revenue responsibility assignment which would result from developing class-specific distribution marginal cost estimates does not, at this time, justify an order requiring Edison to develop such marginal costs.

9. Because marginal T&D costs are currently calculated with a regression analysis which relates growth in T&D investments to growth in T&D demand, we cannot find that agricultural customers are being charged unfairly for urbanization-related costs

10. There is no persuasive evidence that the EPMC method distorts marginal cost price signals.

11. Compared to other AG-TOU customers: (a) Schedule TOU-PA-5 customers use a lower percentage of their annual energy during the summer on-peak period; and (b) the marginal cost of service is lower for Schedule TOU-PA-5 customers.

12. DRA has demonstrated that its regression analysis to measure coincident demand by on-peak energy usage is statistically valid and well within Edison's own standard for statistical validity.

13. Detailed load research data is generally a better approach to MCRR calculations, but DRA has presented statistically valid load characteristic measures which are sufficient to support a separate allocation to Schedule TOU-PA-5.

14. When there is excess capacity, higher cost resources are less likely to be utilized, and it is reasonable to reflect that fact in the way that revenue responsibility is allocated among customers.

15. For MCRR calculations, an ERI adjustment based on a six-year average ERI provides a balance between short-run and long-run considerations because six years is long enough to provide stability and reasonably long-term pricing signals yet short enough to give some weight to short-term capacity surpluses.

16. Using class-specific CRRs to refine MCRR calculations would not result in incorrect price signals if the class-specific CRRs were otherwise found to be valid.

17. Utilities create capacity to meet the diversified load of a system, and reserve margins are planned on a system basis rather than a class-specific basis

18. Scaling each class' load shape up to the system level requires an assumption that the entire system serves only that class' load.

19. Edison's LOLP calculations take maintenance scheduling into account.

20. Loading on Edison's transmission system is more diverse than on the generation system, and loading on the primary distribution system is more affected by simultaneous demands than that which occurs at the customers' points of connection to the distribution system.

21. T&D systems must be sized to meet loads greater than coincident demand but less than noncoincident demand.

22. Use of DRA's recommended shares of 92.29% coincident and 7.71% noncoincident for transmission costs, and 33.19% coincident and 66.81% noncoincident for distribution costs, as revised herein, is a reasonable step towards greater precision in the use of marginal costs to set electric rates.

23. Edison's proposal that nonallocated revenues include those which recover the costs of domestic TOU meters, capacitors which are paid for through the power factor adjustment, facilities for streetlighting customers, and special contacts which avoid or defer self-generation is not contested.

24. Edison's exclusion of revenues collected under the LIRA program from revenue allocation is not contested.

25. Edison does not contest DRA's proposed treatment of the 25% employee discount allowed under Schedule DE as comparable to an

operating cost which is paid for by all customers through an adjustment to total residential sales.

26. Edison's load management programs are in many ways substitutes for development of additional capacity.

27. Edison's proposal that all customer classes pay for load management credits through an EPMC-based allocation is not contested in principle.

28. To implement the principle that all customer classes should pay for load management credits, it is reasonable to add the "costs" of load management credits to the basic revenue requirement which is then allocated to the various customer groups on a capped EPMC basis.

29. There is no evidence that Edison's method of allocating load management credits results in any inappropriate misallocation of revenue responsibility or any undue complication.

30. Edison's agricultural customers increased their expenditures for electricity by 17% between 1985 and 1990 due to increased consumption alone.

31. Customers taking service on Edison's Ag & Pumping schedules have faced financial hardships due to drought conditions, and the severe freeze which occurred in late 1990 and early 1991 provides further justification for moderated increases.

32. Since the EPMC increase for Domestic customers will be less than 2.5% under any likely revenue allocation scenario, the choice of a cap for the Domestic class from those recommended by the parties does not affect the adopted revenue allocation.

33. In this proceeding it is likely that only two rate groups would be affected by any of the capping proposals; both schedules are within the Ag & Pumping group: PA-1 and TOU-ALMP-2.

34. In combination, the financial hardships facing Ag & Pumping customers, the disaggregation of Ag & Pumping rate groups for revenue allocation purposes, and the recognition that marginal

cost measurements may be refined in the future justify a cap of SAPC plus 3.5% for the Ag & Pumping schedules.

35. The Commission has adopted non-uniform caps in the past, and the argument that non-uniform caps are inequitable or discriminatory because different classes would be different distances from EPMC is equivalent to an argument for no caps at all.

36. Circumstances in this proceeding justify a cap of SAPC plus 3.5% for the Ag & Pumping schedules, but in general, a cap of SAPC plus 5% is generally supported by most parties as a reasonable guideline for the Edison system.

37. A cap of 3.5% for the Ag & Pumping groups allows some progress to be made toward EPMC, and the revenue deficiency resulting from this cap does not impose an excessive subsidy burden on other customers.

38. The SAPC associated with currently effective rates and rates scheduled to become effective June 7, 1992 is zero; but the SAPC which should be used for revenue allocation purposes, based on the difference in revenues between January 20, 1991 rates and June 7, 1992 rates, is 2%.

39. The revenue allocation adopted in D.92-01-018 was interim in nature, and the rates which became effective January 20, 1992 never have been in effect during a summer season.

40. This case is an exception to the general rule that we allocate Edison's revenue annually.

41. A departure from the standard practice of considering currently-effective rates is justified by the circumstances of this case, in which two revenue allocations, the first of which was interim in nature, are adopted less than five months apart.

42. There was no opposition to proposals to reschedule consideration of this decision from May 20, 1992 to a later date.

43. The moratorium on increases in Ag & Pumping rates imposed by AB 2236 has expired.

44. There is no indication at this time that any class which has benefited from caps in the past is one which should be floored now for equity reasons.

45. Allocating the subsidy which results from capping to all uncapped classes on an EPMC basis results in equitable treatment of all customers.

46. A floor would not reduce allocation distortions in this case because the revenue deficiency from capping is small.

47. Customers which would be impacted by floors have expressed a clear preference for an EPMC allocation over rate stability.

48. There are no compelling reasons at this time for adopting a floor on the revenue allocated to any class.

49. The following Edison proposals for revenue allocation between GRCs are uncontested: EPMC-based revenue allocations should be adopted in annual ECAC proceedings; the method for calculating MCRR adopted by this decision should be maintained; the incremental energy rates (IERs) adopted in Phase 1 for revenue allocation should remain in effect; the gas price used for developing marginal energy costs should be developed using the methodology adopted in Phase 1; marginal demand and marginal customer costs adopted in Phase 1 should be used and updated in each annual ECAC proceeding by applying the Gross Domestic Product Implicit Price Deflator; and revenue allocations other than those occurring in ECACs should be accomplished on an SAPC basis.

50. The ability of parties to propose alternatives to our guidelines for caps and floors will not significantly burden the processing of future ECACs with unnecessary litigation.

51. Updating the ERI for revenue allocation purposes would add precision to revenue allocation in ECACs, but, for stability in revenue allocation, consistency with use of the same IERs between GRCs, and to reduce litigation over ERIs in ECAC proceedings it is more appropriate to use the same ERI until the next GRC.

52. Uncontested common rate design and tariff issues were resolved as follows:

a. There should be no meter charge for TOU schedules except for Schedule TOU-D and Special Condition 11 of Schedule PA-2, because TOU meter costs are included in the development of rate group MCRR;

b. The contract demand and minimum demand charges on demand-metered schedules in the LSMP, LP, and Ag & Pumping groups should be replaced by a nontime-related demand charge applied to the higher of the current month's maximum demand or 50% of the maximum demand during the previous 11 months;

c. To avoid claims of retroactive ratemaking, application of the demand ratchet should consider only billing information from June 7, 1992 forward;

d. Edison's methodology to calculate the proposed power factor adjustment rates is reasonable;

e. Edison's methodology to calculate the proposed voltage discount rates is reasonable;

f. Edison agrees to market its TOU rates in 1992 and future years and to file a report on the progress of customer participation on its optional TOU schedules in its next GRC;

g. For revenue changes of less than 1% in proceedings between GRCs, an equal ¢/kWh rate design methodology should be used;

h. Rate design in Rate Design Window proceedings should be handled on a case-by-case basis;

i. The CEPC rate design methodology results in changes to customer, energy, and demand charges by the percentage change in revenues allocated to a particular rate schedule's rate group; it should be generally applied in rate design between GRCs except where specific provision for other adjustments has been made in this decision;

j. The average rate limiter should continue to be phased-out in annual ECAC proceedings by increasing the average rate limiter by increments of 3¢ per kWh above the average summer rate for the TOU-8-Secondary (less than 2 kV) Rate Group;

k. The GRC-adopted on-peak rate limiters should be adjusted by the percent change in revenue allocated to the applicable rate group for rate changes occurring between GRCs;

l. It is reasonable to revise the DMS-2 diversity adjustment in annual ECAC proceedings whenever there is a significant change in rates or baseline allowances. The revision should be merely to insert the new Domestic rates and baseline allowances (if applicable) into the DMS-2 diversity service study adopted in the GRC using the same sample of customers and kWh consumption data as in the adopted service study; and

m. Edison's proposed changes to the Preliminary Statement are reasonable and should be adopted, including Edison's proposed Monthly Distribution Percentages for service rendered on and after January 1, 1993.

53. Uncontested domestic rate design issues were resolved as follows:

a. Future reductions in the nonbaseline-to-baseline rate ratio should be reviewed once a year in Edison's annual ECAC proceedings;

b. Except for DRA's proposal to reduce the baseline allowance percentages to the lowest permissible level, no parties oppose Edison's calculation of baseline allowances;

c. A Minimum Average Rate should be applied to Schedule DMS-1 customers so that they will pay at least the average cost of fuel and purchased power as well as the CPUC Reimbursement Fee;

d. Edison's proposed methodology for calculating the diversity adjustment for Schedule DM is appropriate;

e. Edison's proposed methodologies for calculating the diversity adjustment, the cost of service discount and the resulting submetering discount for Schedule DMS-1 are appropriate;

f. The current structure of the DS rate schedule and the 7¢ per kWh Summer Season Premium Charge and Winter Season Discount should be retained; the minimum usage restriction of 1,200 kWh per month should be eliminated;

g. To enhance customer understandability and acceptance, it is beneficial for Schedule TOU-D to have only on- and off-peak periods;

h. The seasons for Schedule TOU-D should be consistent with the seasons used for baseline allowances;

i. The current method of designing the TOU-D rate should be retained to ensure that the rate reflects the marginal costs of providing service during each pricing period;

j. It is appropriate at this time to design the TOU-D rate to be revenue neutral to the regular domestic rate;

k. Edison's proposed TOU-D meter charge, designed to reflect the estimated costs of installing and maintaining domestic TOU meters, is reasonable;

l. The current rate structure and levels of credits provided on Schedule D-APS-2 should be retained;

m. Schedule D-APS-2 should be retitled D-APS for rate simplification, since there is no Schedule D-APS-1;

n. In order to ensure that the percentage of base rate revenues by season will remain at current levels, and that the company's seasonal earnings pattern will not be impacted by the structure of the adopted revenue allocation and rate design, Edison's proposed Domestic Seasonal Rate Adjustment should be adopted;

o. Schedule DM tariff language should be revised to reflect that the schedule has, in recent years, been opened by the Commission to residential hotels and RV parks; and

p. The minimum charge language on Schedule D should be revised to ensure that the charge is assessed on a per meter rather than per single-family accommodation basis.

54. Uncontested LSMP rate design issues were resolved as follows:

a. Schedules GS-SP and GS-TP should be eliminated and Schedule GS-1 should be reestablished;

b. The customer charge for three-phase customers on Schedule GS-1 should be increased by an additional $1.65/month; the customer charge for single-phase customers on Schedule GS-2 should be reduced by $1.65/month below the adopted customer charge for all regular GS-2 customers;

c. LSMP customers with demands in excess of 20 kW should be required to take service on Schedule GS-2 or another applicable demand metered rate schedule;

d. The current load-factor blocked structure for Schedule GS-2 including the 5¢ per kWh second-block energy rate should be retained for now and reviewed in Edison's next GRC;

e. Schedule GS-2-APS should be eliminated and the applicability criterion and structure of Schedule GS-APS should be changed to allow all general service customers to take APS service on this schedule. The current credit levels on this schedule should be retained and the criteria limiting the number of customers taking service on this schedule should be removed subject to equipment availability;

f. Edison should complete its current experimental program on conjunctive billing by June 1992 and file a proposal on the expansion, continuation, or elimination of this program in its next rate design window filing; and

g. The revised methodology and pricing periods used by Edison in the design of Schedule TOU-GS-SOP as discussed in Exhibit 602 should be adopted.

55. Uncontested LP rate design issues were resolved as follows:

a. Customer charges for all LP schedules should be established at their full EPMC levels;

b. The TOU-8 on-peak rate limiters described in Ex. 605 are reasonable;

c. The present structure of Schedule S should be retained;

d. Standby customers should be allowed to take service on SOP rates;

e. Edison agrees with DRA's proposal of an optional real time on-peak demand charge on an experimental basis to be applied to the participating customers' average kW demand during on-peak hours of those days for which forecast temperature equals or exceeds 85°F at the Los Angeles Civic Center;

f. Edison's Real Time Pricing program should be continued with an effective date of

January 1, 1993, no specific termination date, a maximum of 50 participants in 1993, and a rate design based on the general principles used in design of the current program;

g. Edison's proposed terms and conditions for the interruptible tariffs, including the consolidation of Schedule I-6-A and I-6-B into a single Schedule I-6, are reasonable;

h. Schedules I-1 and I-2 should be eliminated on June 7, 1992;

i. Schedules I-3 and I-5 should be eliminated on January 1, 1993;

j. The deficiency resulting from application of the LP interruptible bill limiter should be allocated to the rate groups in the LP Customer group on an EPMC basis;

k. Edison's SPA Rate Option should be extended through the summer of 1993 and its further usefulness for the summer of 1994 should be reviewed in the Rate Design Window filed in December 1993;

l. Edison's proposal to charge excess usage by SPA customers on the normally applicable rate schedule is appropriate;

m. Edison's proposal to revise the billing procedure for Schedule TOU-8-CR-1 should be adopted;

n. Customers served under a firm service LP schedule whose monthly maximum demands have registered below 500 kW for 12 consecutive months should be ineligible for service under that schedule; and

o. Schedule TOU-8-APS should be eliminated and Schedule GS-APS be made available to LP APS customers.

56. Uncontested Ag & Pumping rate design issues are resolved as follow:

a. The classification of Ag & Pumping rate schedules into the Ag & Pumping rate groups as proposed by Edison should be adopted;

b. Edison's proposed TOU meter charge for customers opting for Special Condition 11 of Schedule PA-2 is reasonable;

c. The current load-factor blocked structure of Schedule PA-2 including the 5¢ per kWh second-block energy rate should be retained for now and reviewed in Edison's next GRC;

d. The current energy rate relationships by time period and season on closed TOU schedules should be maintained;

e. Energy rate relationships in the on- and mid-peak periods on open Ag & Pumping TOU schedules in this proceeding should be set according to the ratio of marginal energy costs in each period;

f. For schedules where the off-peak and SOP rate levels are currently at 5¢ per kWh and 3.5¢ per kWh, respectively, these levels should be retained;

g. The current structure of Schedule PA-1 should be retained;

h. The customer and demand charges for Schedule TOU-PA-5 should be set at the same level as similar charges on other AG-TOU demand rate options;

i. Except for the adopted suballocation of revenues to Schedule TOU-PA-5, the current structure of the rate (i.e., high minimum charge) should be retained;

j. Energy rate relationships in the on-, mid-, and off-peak periods on Schedule TOU-PA-5 in this proceeding should be set according to the ratio of marginal energy costs in each period;

k. The Monthly Minimum charge on Schedule TOU-PA-5 should be applied to the Annual Maximum Demand rather than the contract demand since the contract demand provisions on all schedules are proposed to be eliminated and replaced by a ratcheted demand provision;

l. The methodology and pricing periods currently used in the design of Schedule TOU-PA-SOP as discussed in Exhibit 602 should be retained;

m. Edison's proposed Schedule TOU-PA-SOP-I should be made effective on June 7, 1992;

n. Schedule AP-I should be closed to new Schedule TOU-PA-SOP customers on June 7, 1992 and as of January 1, 1993, the tariff language for AP-I should be revised to preclude all TOU-PA-SOP customers from taking service under AP-I;

o. An Ag & Pumping interruptible bill limiter, similar to the interruptible bill limiter proposed by Edison in this proceeding for LP customers, should be made effective January 1, 1993;

p. The deficiency resulting from application of the Ag & Pumping interruptible bill limiter should be allocated to the rate groups in Ag & Pumping Customer Group on an EPMC basis;

q. Edison's proposal to allow nonagricultural and nonpumping loads on Ag and Pumping schedules as long as at least 70% of a customer's load is for Ag & Pumping purposes should be adopted; and

r. Schedule TOU-PA-1 should be eliminated on June 4, 1995.

57. Uncontested SL rate design issues are resolved as follows:

a. The current additive rate form of SL rate schedules should be retained but primary service customers should be provided with a voltage discount;

b. The cost of a standard installation (wood pole, mastarm, and insulator bolt) should be maintained at the levels adopted in Edison's 1988 GRC;

c. SL facilities should be valued using the Replacement Cost New-Economic Carrying Charge (RCN-ECC) methodology;

d. Manufacturer kWh ratings for various types of lamps should be used;

e. Current hours of operation for all-night service should be retained but burn hours for midnight service should be increased form 2,090 hours to 2,170 hours per year;

f. Both High Pressure Sodium Vapor and Low Pressure Sodium Vapor lamps should be offered to Schedule OL-1 customers; and

g. The de-energized service option currently offered on Schedule LS-1 should be eliminated.

58. Significant bill increases for some customers could result from adopting EPMC-based customer charges and minimum charges at this time.

59. The marginal costs adopted in Phase 1 of this GRC placed 100% of the transformer costs in customer costs instead of distribution costs.

60. The definition of marginal customer costs and marginal distribution costs may change in the next GRC.

61. Edison and DRA agree on implementation of experimental real-time on-peak demand charges and moderate increases in the time-related demand charges on TOU schedules, and other parties generally support such increases.

62. Traditional time-related demand charges do not reflect costs as well as some have assumed, and correlation between on-peak billing demand and coincident demand is spurious.

63. Reasonable actions for expanding real-time pricing options at this time include: expansion of Schedule RTP-2 or its successor to up to 50 customers; a cooperative effort of Edison, DRA, and other interested parties to review Edison's initial experimentation with real-time pricing and to formulate a longer-term plan before 1993; and a new real-time on-peak demand charge as an experimental rate option for TOU-8 customers, which measures a customer's average load during on-peak hours of summer weekdays when the forecast high temperature for the day equals or exceeds 85 degrees at Los Angeles Civic Center, based on the National Weather Service forecast.

64. It is appropriate to await further experimentation before we order Edison to propose implementation of real-time pricing for additional customer classes.

65. Application of Edison's proposed off-peak energy charge of 5¢/kWh and SOP energy charge of 3.5¢/kWh to Ag & Pumping schedules and Schedule TOU-GS is not contested.

66. A portion of the system coincident capacity cost is paid for by customers who contribute to system efficiency by consuming energy during off-peak and mid-peak periods.

67. Customers with high-load factors bear a disproportionate state of coincident capacity costs, paying as much as 20% to 30% above the EPMC level for their off-peak consumption; this is unfair to high-load factor customers and provides an incorrect price signal.

68. The time-differentiated IERs adopted in Phase 1 of this GRC increased the summer on-peak to mid-peak ratio of marginal energy cost from 1.25:1 to 1.56:1, resulting in a significant increase in summer on-peak energy charge.

69. Ideally, the pricing signal to be sent to customers through n- and mid-peak energy charges is the relative cost of using an additional kWh between the on- and mid-peak periods.

70. For the LSMP and LP schedules, collecting residual coincident capacity costs, which are not recovered in time-related demand charges, in the energy charge associated with the time period in which coincident capacity costs are incurred will be fairer and will more accurately reflect the cost imposed on the utility as a result of demand imposed during each time period.

71. It is reasonable to design on- and mid-peak energy rates for the TOU-8 and TOU-GS schedules based on marginal energy cost ratios plus 15% of uncollected coincident capacity costs allocated to pricing periods by LOLP.

72. Except for Schedule D-LI, the base rate minimum charge for Domestic customers has not changed since the current 10¢ per day level was adopted in 1985.

73. The full EPMC level of customer costs for Domestic customers is about 25¢ per day.

74. Increasing the base rate minimum charge for Domestic customers by 15% per year reasonably balances considerations of rate stability and the need to move minimum charges toward marginal cost, and, eventually their EPMC levels.

75. The ratio of Edison's Domestic nonbaseline to baseline rate was reduced from 1.39:1 to 1:33:1 in the recent ECAC proceeding.

76. The Commission has determined that closure of tier differentials commensurate with a 15% LIRA discount should be pursued.

77. There is insufficient basis in this record to support a change in policy on tier closure.

78. Edison's proposal for a 2.5% limit in baseline rate increases should enable it to reach a nonbaseline-to-baseline rate ratio of 1.15:1 by the 1995 GRC and is reasonable as a guideline for setting rates in ECACs.

79. Reducing the baseline allowances to the minimum levels permitted by law could cause bill increases of 4% to 8%.

80. Customers who heat their homes electrically would be significantly impacted by reducing baseline allowances to the minimum permitted by law, since they would generally lose over 100 kWh in their monthly baseline allowance.

81. There is no sound basis in this record for assessing the net conservation effect of any given change in baseline allowances.

82. Growing numbers of persons are using RVs as their only or primary residences.

83. Virtually no RV parks in California have qualified for submeter service under current schedule options.

84. Edison needs to be able to visually inspect RV parks and review their records to determine compliance with tariff terms.

85. Edison's proposed 75% occupancy requirement would dissuade park operators from attempting to become eligible for the proposed DMS-3 rate.

86. Tariff criteria regarding customer intent to achieve a predetermined occupancy rate are unfair because economic conditions beyond a park operator's control could frustrate the operator's best intentions.

87. Edison will be able to administer tariff requirements with adoption of the agreed-on proposals for eligibility declarations and on-site verification of books, records, and facilities without the 75% occupancy requirement.

88. Separation of submetered systems from nonsubmetered systems within parks will avoid administrative problems.

89. RV parks normally separate short-term and long-term tenants in different sections.

90. Schedule TOU-D has not been successful since there are no customers on it.

91. Two obstacles to participation in Schedule TOU-D are complexity and high summer on-peak energy charges.

92. DRA's two-schedule proposal for Domestic TOU options best meets our objectives for a domestic TOU program.

93. The customer charges in some GS schedules are below the marginal costs adopted in Phase I.

94. An increase in the customer charge on Schedule GS-1 from 30¢ per day to 40¢ per day is consistent with the need for both rate stability and progress towards EPMC.

95. A 33% increase which raises the customer charge by approximately $3.00 per month is not insignificant, but it is less significant than one with a larger dollar impact.

96. Increasing the GS-1 customer charge by one-fourth of the difference between its January 1992 and its EPMC levels in annual ECAC proceedings is appropriate as a guideline to continue progress towards a cost-based customer charge between GRCs.

97. The increases proposed by DRA for Schedule GS-2 and Schedule TOU-GS are relatively significant in dollar terms.

98. Increasing the customer charges for Schedule GS-2 by CEPC plus 10% and for Schedule TOU-GS by CEPC plus 20% at this time reasonably balances stability and costs; and the same rate of increase is reasonable as a guideline for future proceedings.

99. The customer charge for Schedule TC-1 can be set at its full EPMC level with negligible effect on customer's bills.

100. Increasing nontime-related demand charges on GS-2 by CEPC plus 10%, and on TOU-GS and TOU-GS-SOP by CEPC plus 20% balances stability and movement toward EPMC-based charges, and these same rates of increase should be observed as guidelines in future proceedings until full EPMC charges are achieved.

101. There is no compelling reason for raising the SOP energy rate in Schedule TOU-GS-SOP from 3.5¢/kWh to 4.0¢/kWh.

102. It is reasonable to reflect the noncoincident share of transmission cost, and increase the nontime-related demand charge for TOU-8 subtransmission service to the full EPMC-based level.

103. For the TOU-8 primary and secondary nontime-related demand charges, limiting the changes to CEPC plus 10% or even 20% does not provide enough movement toward EPMC levels.

104. TOU-8 demand charges presently recover about 47.2% of EPMC demand-related costs.

105. It is reasonable to provide for movement of 50% of the distance to EPMC for TOU-8 primary and secondary nontime-related demand charges.

106. Although Edison's rates do not adequately recover coincident capacity costs in the various on-peak time periods, there is broad-based agreement on the need for tempered increases in on-peak demand charges in the LP schedules.

107. Increases in time-related demand charges in the LP schedules by CEPC plus 20% for subtransmission service and CEPC plus 10% for primary and secondary service are moderate and they reasonably balance rate stability and movement to EPMC charges.

108. Increasing the time-related demand charges in the SOP schedules by CEPC is reasonable because they are close to the EPMC level.

109. The off-peak energy charge of 5¢/kWh on the TOU-8 schedules has been maintained at the same level since Edison's last GRC.

110. The off-peak energy charge of 5¢/kWh charge exceeds the full EPMC level for each of the TOU-8 service levels and for both the summer and winter periods, and results in inaccurate price signals.

111. Movement of the TOU-8 off-peak energy charges one-half the distance to their full EPMC levels in this proceeding, with a floor of marginal cost, is reasonable because it balances the need for stability against costs.

112. Suballocation of revenues to current interruptible customers and firm customers on a customer, rather than a load basis can create a mismatch between revenue allocation and applicability criteria.

113. There is no evidence of the impact on firm customers of the proposed firm/interruptible suballocation.

114. Moving demand and energy charges toward their cost-based levels would yield similar results to those that would be obtained by suballocation revenues to firm and interruptible customers.

115. Differences in types of service between firm and interruptible customers are unclear, since both groups have the same TOU periods, the same general pattern of demand and energy charges, and the same range of load size.

116. Suballocation of revenues to firm and interruptible customers has value largely because the LP schedules are not sufficiently cost-based, but the reason the schedules are not cost-based is largely due to our continuing concerns about stability.

117. Designing the TOU-8-SOP rate schedules to be revenue neutral as proposed by Edison will simplify rate design and should result in a more stable relationship between the TOU-8 and TOU-8-SOP energy rates than the more complex iterative methodology which was adopted in the last GRC.

118. At the current time 13 customers are served on Schedule TOU-8-CR-1.

119. Schedule TOU-8-CR-1 customers saved $3.2 million compared to charges that would have applied under otherwise applicable rates, based on 1990 billing parameters.

120. The savings enjoyed by Schedule TOU-8-CR-1 customers will be decreased by approximately 60% as a result of Edison's proposed new billing procedure.

121. Even if past contributions to fixed costs have not been optimal, it is likely that Schedule TOU-8-CR-1 has resulted in increased sales on the Edison system and that other ratepayers have benefited due to the contribution to fixed costs that would not have otherwise occurred.

122. The improved billing procedures proposed by Edison for Schedule TOU-8-CR-1, and the added requirement that customers sign an affidavit that they would not increase their load in the absence of the option, will provide certainty regarding the true

incremental nature of the schedule and help ensure that the optimal contribution to margin is obtained.

123. It is reasonable to continue basing the energy charge for eligible SPA purchases on a target margin contribution of 3¢/kWh.

124. Avoided energy cost changes significantly from one year to the next. It ranged from 4.2¢ to 4.8¢ in the summer of 1990 then dropped to 3.5¢ a year later.

125. Using a forecast summer on-peak marginal energy cost of approximately 4.5¢/kWh as a forecast proxy for the avoided on-peak energy cost, it is reasonable to adopt a minimum rate of 7.5¢/kWh for SPA purchases to provide reasonable assurance that the 3¢/kWh contribution is realized for the future.

126. Some customer charges in the Ag & Pumping rate schedules are far below their 100% EPMC levels.

127. It is appropriate at this time to increase the customer charge by 10% on Schedules PA-1, TOU-ALMP-2, and TOU-PA-1, by $1.00 on Schedule PA-2, and by CEPC on other Ag & Pumping schedules, and to apply these rates of increase as guidelines in ECAC proceedings.

128. Nontime-related demand charges on some Ag & Pumping schedules are significantly below marginal cost.

129. Increasing nontime-related demand charges and connected load charges by CEPC plus 10% on Schedules PA-1, PA-2 and TOU-PA-1 and by CEPC plus 20% on open TOU schedules yields an appropriate balance of concerns about stability, bill impacts, and the need to close the cost-rate gaps for these charges.

130. These same rates of increase are reasonable as a guideline for further increases in proceedings between now and the next GRC.

131. There is insufficient basis for changing the current structure of Schedule AP-I.

132. An interruptible option for the TOU-PA-SOP schedule is reasonable.

133. The most simple and practical way to provide an interruptible credit to Ag & Pumping customers is on a flat ¢/kWh basis.

134. It is reasonable to cancel Schedule TOU-PA-3 because there are no customers taking service on the schedule and no known potential customers even though it has been available for four years.

135. Schedule TOU-ALMP-2 has been closed to new customers since 1988, but more than 1,300 customers remain on the schedule.

136. Schedule TOU-ALMP-2 has a low customer charge and no demand or connected load charge, but does have TOU energy charges.

137. The TOU-ALMP-2 rate group is the furthest from a full EPMC revenue allocation in this proceeding.

138. Edison is not and should not be indifferent to a rate structure merely because it collects its revenue requirement and the customers who benefit from that rate structure are satisfied.

139. Demand charges are essential for informing customers about the generation, transmission, and distribution costs incurred by the company as a result of their usage patterns, and are particularly important for Schedule TOU-ALMP-2 customers because of their high use.

140. Schedule TOU-ALMP-2 does not inform customers of the costs they impose, since customers can impose different costs on the system, yet have identical bills.

141. A schedule like TOU-ALMP-2 encourages low-load factors and high costs of service.

142. Auxiliary relays are required to open and close streetlight circuits at traffic-controlled intersections.

143. Virtually all LS-2 service is provided at 120 volts.

144. If anything, page 411 of the Electric Service Requirements Manual shows that relays are company-owned.

145. Special Condition 3 of Schedule LS-2 requires that those relays which are not furnished by the company be furnished by the

customer and installed and maintained under company specifications, but it does not indicate the circumstances under which a customer might own the relay.

146. Edison has established that it provides relay equipment for which the cost should be reflected in facilities charges for LS-2 customers.

147. The cable included in the customer charge paid by LS-2 customers is a service drop from the transformer to an auxiliary relay or compression splice, whereas the aluminum conductor for which a separate facilities charge is proposed connects the auxiliary relay to the customer's service point.

148. Edison has correctly included the cost of auxiliary relay equipment and aluminum conductor in the calculation of facilities costs to be paid by LS-2 customers.

149. Edison and CAL-SLA agree that increases in facilities and other nonenergy-related costs for Schedules LS-2 and LS-3 should be limited to 10% per year, and that the resulting deficiencies should be collected from all streetlighting schedules, including Schedules LS-2 and LS-3.

150. Energy charges in the SL schedules will be reduced through the normal rate design process in future proceedings as nonenergy charges increase.

151. Street light installation delays are often attributable to the customer or developer.

152. Edison has a contractual requirement with its streetlighting contractors to complete all installations within 30 days after Edison releases a work order.

153. Edison releases a work order only when site preparation allows.

154. Sufficient need for tariff standards for installation times has not been demonstrated.

155. Edison responded to 91,187 streetlight maintenance calls from October 1, 1989 to October 26, 1991 with an average response time of 2.8 days on a system-wide basis.

156. The average response time was 4.4 days within the City of Santa Barbara for 263 calls during a similar period.

157. On an overall basis, Edison is responding reasonably to street light maintenance calls, but maintenance response time problems could still exist.

158. The need for and propriety of a binding tariff rule for maintenance response time has not been demonstrated in this proceeding.

159. Approximately 960 MW of Edison's customer load can be signaled for interruption

160. The "supply side" approach to analyzing interruptible credits is appropriate because it focuses on the costs avoided by the interruptible program.

161. If the interruptible rates were to be calculated on an EPMC basis without assignment of coincident capacity costs, the result would be equivalent to a credit which exceeds the cost avoided by the program, in which case it would be cheaper for the utility to obtain the resource at marginal cost than to pay credits above marginal cost for the same capacity.

162. There is a planning benefit in the interruptible program which extends to the T&D system as well as the generation system.

163. The interruptible program avoids coincident T&D costs, and the credit should reflect this fact.

164. It is reasonable to assume that 92.35% of marginal transmission capacity costs and 33.17% of the distribution system capacity costs are avoided by the interruptible program.

165. Customers who actually impose coincident demands should pay for these coincident T&D costs.

166. When the system has excess capacity and the ERI is less than 1.0, a utility will not build additional combustion turbines

and the value of interruptible load is less than the full cost of a combustion turbine.

167. The ERI-adjusted annualized cost of a combustion turbine is the most appropriate measure of the marginal generation cost.

168. Use of a six-year average ERI figure to adjust the marginal generation cost provides a balance between short-term and long-term costs and it provides stability in the interruptible credit.

169. Using a long-term ERI value of 1.0 at the present time would emphasize a long-term view which gives too little weight to the current excess capacity situation.

170. The uncontested calculation of the six-year average ERI, including the floor ERI of 0.1 adopted in D.91-11-057, is 0.653. This value reflects agreement that the ERI used for the interruptible credit should be the average of the "interruptible in/out" calculations, and should be based on the "barebones" resource plan with exclusion of uncommitted Demand-Side Management load.

171. For purpose of the interruptible credit, the six-year average ERI adopted today should be used in ECAC proceedings between GRCs.

172. The fact that interruptible load is available only 150 hours per year, whereas a combustion turbine is available year round, does not affect the reserve margin.

173. In years when there is significant excess capacity, as indicated by the six-year average "interruptible in/out" ERI of 0.653, Edison can rely on its existing capacity to satisfy reserve requirements.

174. The avoided generation cost should not be adjusted upward by the CRR to reflect the reserve margin on Edison's system when Edison can rely on its existing capacity to satisfy reserve requirements.

175. The level of the interruptible credit for the generation voltage level which is based on our adopted methodology is calculated as follows:

Avoided Cost of Generation	\$82.15 x 0.6530 =	\$53.64
Avoided Cost of Transmission	\$32.70 x 0.9235 =	\$30.20
Avoided Cost of Distribution	\$49.82 x 0.3317 =	\$16.53
Total		\$100.37

176. Edison proposes to design rates for Schedule I-6 by allocating the annual \$/kW credit to various pricing periods on an LOLP basis and providing the credits in demand and energy charges based on the relationship of these charges to their EPMC levels.

177. Edison's Schedule I-6 rate design can be simply revised to allocate the remaining interruptible credit to energy charges based on inclusion of uncollected coincident capacity costs in the ratio of marginal energy costs.

178. The majority of Edison's interruptible customers are currently served under Schedules I-3 and I-5, which provides the interruptible credit on a flat cents/kWh basis.

179. Schedules I-3 and I-5 are scheduled for cancellation.

180. By providing the interruptible credit on a flat cents/kWh basis, Schedule TOU-8-I would eliminate the price signals sent when the credit is allocated to different rate components by pricing periods.

181. Under proposed Schedule TOU-8-I, customers would not need to have any interruptible load in peak hours, and could have the majority of their loads in off-peak hours and still obtain a sizable credit.

182. Schedule I-3 and I-5 customers targeted by proposed Schedule TOU-8-I have been on notice since Edison's last GRC that the schedules would be terminated.

183. The rate stability concerns which Edison addresses with its proposed Schedule TOU-8-I are adequately addressed by bill-limiter provisions.

184. Edison and DRA agree on the concept of a bill limiter to mitigate the bill impacts faced by some interruptible customers who will move from schedules which have been targeted for elimination in 1992 and 1993.

185. Although customers targeted by bill limiters have been on notice since 1988 that certain interruptible schedules would be eliminated, these customers could have had no way of knowing that significant reductions in the credit levels would be adopted in this proceeding.

186. It is reasonable to adopt a bill limiter provision for interruptible schedules by using the mechanism proposed by Edison but with percentage increases of 15% and 30% for 1993 and 1994 respectively.

187. We determined in D.91-12-076 that R.91-08-003 is the proper forum for consideration of the concept of interruptible bidding.

188. Tariff language changes are not necessary at this time to create a pool of available customers for potential interruptible bidding programs because the Commission already has the authority to terminate or modify existing interruptible contracts.

189. Requiring customers to make a commitment to either risk the uncertainty of an unknown interruptible bidding program or to relinquish bill impact protection which we have found to be appropriate is not a fair choice for the Commission to impose on those customers.

190. The interruptible credit is based on the avoidance of costs by the interruptible load in the planning process, and is thus based on the current nature of the program as a source of capacity in system emergency conditions.

191. Broadening the criteria for interruptions to include nonemergency conditions may require incorporation of additional credits and could place additional burdens on system operators.

192. An economic interruption would be unlikely during the current GRC cycle.

193. DRA's proposal of an economic criterion for calling interruptions is not ready for implementation.

194. Edison proposal to refine the criteria for calling interruptions is an appropriate step that provides more information to all parties about how the program works.

195. Edison should include in its next GRC filing an analysis of whether broadened interruption criteria, including an economic criterion, should be adopted in that proceeding.

196. Edison's proposed 7¢/kWh criterion for calling interruptions is based on a recognition that when a shortage of supply exists on Edison's system, it may be possible to remedy the situation with cost-effective purchases of capacity and energy.

197. The main value of the interruptible program is in the availability of load as a long-term planning resource, and the value of the program does not vary with specific instances of operation of the program.

198. TURN's pay-for-performance proposal would add volatility to the credit level, and the proposed credit levels greatly undervalue the interruptible load.

199. TURN's pay for performance proposal results in an incorrect incentive for system dispatchers because with each interruption, Edison would have to pay $4 to $8 million.

200. Audit curtailments are undesirable because they affect all customers, not just those who enrolled in the program with the expectation of not being interrupted; and unnecessary because Edison has proposed a more effective enforcement program consisting of high penalties for noncompliance

201. The need for testing equipment is not analogous to "testing" customers.

202. In the last GRC the limit on the allowed number of interruptions was set at 25 for Schedule I-6, while other schedules

which are scheduled for cancellation have a lower limit of 15 interruptions.

203. Customers were notified in Edison's last GRC that they would be moved to Schedule I-6, and have therefore been aware of the change in the number of allowable interruptions.

204. Edison serves 1,605 master-metered mobilehome park accounts with 109,727 submetered spaces under Schedule DMS-2.

205. DMS-2 customers bill their submetered tenants at the Schedule D rates and receive a DMS-2 Discount.

206. Edison selected a random sample of 37 mobilehome parks out of 391 parks on Edison's system where the tenants are directly served and metered by Edison.

207. The 37 park sample of individually-served parks developed by Edison was designed and selected based on principles of statistical sampling theory

208. It was appropriate to develop the sample on a park basis since diversity and line losses are park-level phenomena.

209. The 37 park sample does not result in a small park bias.

210. Stratification of the sample on the basis of park size and age was undertaken to to improve precision in estimates of the mean.

211. In the absence of correlation between the stratifying variables and the factor being measured, a stratified sample does not result in bias in the cost of service and diversity estimates.

212. Edison's weighting process yields a better reflection of size and age characteristics of the DMS-2 population.

213. A sample of 232 parks which was used for a cost of service service study in the last GRC is not as reliable as the 37 park sample.

214. Losses and diversity are separate phenomena which should be measured and accounted for separately.

215. The diversity factor should be based on the actual consumption of submetered users.

216. Actual service lives can exceed book lives, and utilities do not revise plant estimates for other ratemaking purposes until plant facilities are actually removed and replaced.

217. Since DMS-2 customers pay Edison according to Schedule D and receive payments from submetered users according to Schedule D, they do not effectively pay for master meter and related facilities through payment of the Schedule D rate.

218. WMA Alternative 1 is based on the 232 park sample which we have found to be less reliable than Edison's new sample.

219. WMA Alternative 3 is based on Edison's average cost of providing distribution service to all domestic customers.

220. There is no basis for using system-average costs to measure costs that Edison avoids by not providing distribution services within DMS-2 parks, when data from a service study specifically designed to measure those costs are available.

221. Based on the 37 park sample, the average line loss factor was 2.07%; and when weighted for the size and age characteristics of the DMS-2 population, the line loss factor is 2.22%.

222. To measure energy losses in mobilehome parks, Edison used generally accepted engineering loss formulae and applied them to field data on conductors and transformers from the 37 parks.

223. Edison's line loss service study is reasonable for estimating the losses Edison would incur if it served the DMS-2 parks directly.

224. If Edison were to serve the parks directly it would be responsible for theft to the same extent it is now responsible for theft on other parts of the distribution system.

225. WMA's attrition percentages are based on rejected cost of service estimates.

226. Adapting Edison's attrition formula to the DMS-2 cost of service service study would require development of substantial new information which is not currently available.

227. If projected costs for a single year systematically understate the allowed costs over the three-year rate case cycle, and if the understatement is significant, the result is inconsistent with PU Code § 739.5(a).

228. Without the BREC provision, some DMS-2 customers would provide negative base rate revenues at the expense of other customers.

229. Some DMS-2 customers pay average rates which are below the MAR level.

230. The MAR provision would set a minimum rate of 5.301¢/kWh, which is less than the rate paid by TOU-8 Subtransmission customers.

231. Minimum charge provisions such as the BREC and MAR mechanisms are appropriate to ensure that cross-subsidization does not occur or is minimized, since it would not be fair to other customers to allow such cross-subsidization.

232. WMA's Alternative 2 proposal is not consistent with PU Code § 739.5(a).

<u>Conclusions of Law</u>

1. Marginal cost principles should be the starting point and the central focus of revenue allocation and rate design for setting Edison's rates.

2. The use of marginal cost principles to set Edison's rates should be tempered with consideration of other ratemaking principles, including rate stability, avoidance of harsh bill impacts where reasonably possible, the need for customer understanding and acceptance of rate structures, and a recognition that the ability to measure marginal costs should improve over time.

3. The rates to be adopted by this decision should be designed to collect Edison's authorized test-year 1992 revenue requirement of $7,479.16 million.

4. Edison's request for an increase in its authorized revenue requirement for the cost of electric meters could have and therefore should have been addressed in Phase 1 of this GRC.

5. The forecast of Edison's customers and sales adopted by D.92-01-018 should be used for this proceeding.

6. Marginal costs which result from application of the methodology adopted in Phase 1 of this GRC and the average gas price of $2.83 per MMBtu adopted in D.92-01-018 should be used for this proceeding.

7. While it is not appropriate at this time to order Edison to conduct a specific marginal cost service study, Edison should monitor developments in marginal costing, including any that may occur in the current PG&E GRC, and proceed with all appropriate and cost-effective marginal cost methodology refinements in time for its next GRC.

8. MCRR calculations should be adjusted by the EPMC method to ensure that the total of the revenue allocated to the various rate groups equals the total allocated revenue requirement.

9. Edison's uncontested proposal for disaggregation of rate groups should be adopted.

10. A separate EPMC allocation based on load information developed by DRA for the TOU PA-5 schedule should be adopted for this proceeding.

11. It is appropriate to give some weight to the fact that Edison's generation capacity situation can be expected to change over time, and therefore, to use a six-year average ERI adjustment of 0.78 to calculate Edison's MCRR.

12. Use of a single CRR of 1.15 rather than class-specific CRRs to calculate MCRR results in a reasonable allocation of generation cost among customer classes.

13. Coincident shares of transmission costs and distribution costs should be set at approximately 92% and 33%, respectively, for revenue allocation and rate design purposes.

14. The adopted revenue allocation should reflect Edison's uncontested recommendations for treatment of nonallocated revenues, LIRA revenues, and DRA's proposal for allocating the cost of employee discounts under Schedule DE to all customers through an adjustment to total residential sales.

15. Load management credits should be treated as additional revenue requirement for revenue allocation purposes.

16. The use of caps to mitigate rate increases can be appropriate in EPMC revenue allocations.

17. For the purpose of setting rates to become effective June 7, 1992, revenue allocation should be based on a cap of SAPC plus 3.5% for the Ag & Pumping schedules and a cap of SAPC plus 5% for all other rate groups.

18. Adoption of different caps for different classes does not result in undue discrimination.

19. For purposes of setting caps for revenue allocation, it is appropriate to base the SAPC component of the adopted caps on the revenue allocation which formed the basis for rates in effect immediately prior to January 20, 1992.

20. AB 2236 no longer governs or limits the revenue allocation to be adopted in this proceeding.

21. A floor on revenue allocation should be rejected for purposes of this proceeding.

22. The revenue deficiency which results from capping should be allocated on an EPMC basis to all groups that are not capped.

23. Edison's uncontested proposals for revenue allocations which occur between now and the next GRC are reasonable and should be adopted.

24. When circumstances so warrant, parties should be able to propose, in future ECAC proceedings, caps and floors which depart from our guidelines of achieving EPMC by the next GRC, setting caps at SAPC plus 5%, and not applying floors.

25. The ERI adopted in this decision should be used between GRCs for purposes of revenue allocation.

26. The uncontested rate design proposals listed in Findings of Fact 52 through 57 should be adopted.

27. For stability reasons it is appropriate at this time to temper marginal customer cost-based increases in customer charges, minimum charges, and nontime-related demand charges, but the extent to which this principle should be reflected in individual schedules should be addressed on a case-by-case basis.

28. Despite concerns about the use of traditional on-peak demand charges for reflecting coincident capacity costs in rates, we should continue to authorize the use of these charges and to move their levels closer to marginal costs.

29. Expanded use of real-time pricing should be encouraged as proposed by DRA, except that we will not order Edison to propose real-time schedules for additional classes.

30. Edison should be directed to continue monitoring its real-time pricing program and related programs of other utilities and report on the need for and propriety of further program expansion in the next GRC.

31. For the TOU-8 schedules and Schedule TOU-GS, residual coincident capacity costs should be at least partially collected in the energy charge associated with the time period in which coincident capacity costs are incurred based on marginal energy cost ratios plus collection of 15% of uncollected coincident capacity allocated to pricing periods by LOLP.

32. Even though the domestic customer class is at its full EPMC allocation, we should seek to attain rate structures within the class that are closer to marginal cost principles; DRA's proposal to increase the minimum charge by 15% per year should therefore be adopted.

33. The Domestic rates adopted by this decision should be based on the tier-differential ratio of 1.33:1 which was just recently adopted in D.92-01-018.

34. Tier differentials commensurate with a 15% LIRA discount should be pursued in Edison's annual ECAC proceedings.

35. A 2.5% limit in baseline rate increases should be adopted as a guideline for setting Domestic rates in Edison's ECAC proceedings until the next GRC.

36. Edison's proposed baseline allowances should be adopted.

37. To assure fairness among RV park users and to promote energy conservation, RV park operators should be permitted to submeter electric service to month-to-month park occupants and should be entitled to baseline allowances and LIRA program benefits.

38. RV park owners should not allowed to commingle submetered spaces served under Schedule DMS-3 with nonsubmetered spaces under the same master meter.

39. Edison's proposed Schedule DMS-3 should be adopted without the 75% occupancy requirement.

40. Two Domestic TOU options should be adopted, with one including a baseline credit and the other excluding the credit.

41. The customer charge on Schedule GS-1 should be increased from its present 30¢ per day to 40¢ per day.

42. The customer charges on Schedule GS-2 and Schedule TOU-GS should be increased by CEPC plus 10% and CEPC plus 20%, respectively.

43. The customer charge for Schedule TC-1 should be set at its full EPMC level.

44. Nontime-related demand charge increases of CEPC plus 10% for Schedule GS-2 and CEPC plus 20% for Schedules TOU-GS and TOU-GS-SOP should be adopted.

45. The SOP energy rate in Schedule TOU-GS-SOP should remain at 3.5¢/kWh.

46. The nontime-related demand charge for subtransmission service should reflect the noncoincident share of transmission cost at its EPMC level.

47. Nontime-related demand charges for TOU-8 primary and secondary schedules should be moved 50% of the distance to EPMC.

48. Time-related demand charges in the TOU-8 schedules should be increased by CEPC plus 20% for subtransmission service and CEPC plus 10% for primary and secondary service.

49. Time-related demand charges in the SOP schedules should be increased by CEPC.

50. The TOU-8 off-peak energy charges should be moved one-half the distance to their full EPMC levels in this proceeding, with a floor of marginal cost as recommended by Edison.

51. TOU-8-PRI energy charges should not be greater than TOU-8-SEC energy charges because energy line losses at secondary voltage exceed those at primary voltage.

52. The TOU-8-SOP rate schedule should be designed using the methodology proposed by Edison

53. Schedule TOU-8-CR-1 should be retained and improved as proposed by Edison.

54. Edison should service study and report on the need for, and appropriateness of, continuing Schedule TOU-8-CR-1 in its GRC filing. As part of that service study, Edison shall evaluate whether the affidavit requirement remains sufficient to ensure that the load on this schedule is truly incremental.

55. The energy charge for eligible SPA purchases should be based on a minimum rate of 7.5¢/kWh to provide reasonable assurance that a 3¢/kWh contribution is realized for the future.

56. Customer charges in the Ag & Pumping schedules should be increased by 10% on Schedules PA-1, TOU-ALMP-2, and TOU-PA-1, by $1.00 on Schedule PA-2, and by CEPC on other Ag & Pumping schedules.

57. Nontime-related demand charges and connected load charges should be increased by CEPC plus 10% on Schedules PA-1, PA-2 and TOU-PA-1 and by CEPC plus 20% on open TOU schedules.

58. Edison's proposals to maintain the structure of Schedule AP-1 and to establish Schedule TOU-PA-SOP-1 should be adopted.

59. Schedule TOU-PA-3 should be eliminated at this time.

60. Schedule TOU-ALMP-2 should be eliminated in three years.

61. Edison's proposal for LS-2 facilities charges is appropriate and should be adopted.

62. As part of its next GRC filing, Edison should include an analysis of whether total facilities charges for Schedule LS-1 should be frozen, with recovery of differences between the actual installation costs and the facilities allowance from applicants requesting new streetlights.

63. Edison should evaluate options for replacing series circuits as proposed by CAL-SLA and report on the outcome of this effort in its next GRC.

64. Edison's proposals for SL rate design should be adopted.

65. Because long response times for street light maintenance calls are not acceptable from a public policy standpoint, Edison should conduct a more complete analysis of maintenance response times for presentation in its next GRC. As part of that presentation, Edison should address whether workable tariff provisons to better ensure timely responses are appropriate.

66. The supply-side approach to analyzing the interruptible program should be continued since it provides the interruptible customers with a credit equivalent to the costs avoided by the interruptible program.

67. An interruptible credit of $100.37 at the generation voltage level and related credits for the other service levels are based on our adopted methodology and should be adopted for designing the interruptible schedules.

68. Edison's proposed Schedule I-6 rate design should be adopted with a revision which provides for allocating the remaining interruptible credit to energy charges based on inclusion of uncollected coincident capacity costs in the ratio of marginal energy costs.

69. Proposed Schedule TOU-8-I should not be implemented since it is not a cost-based option and other measures are appropriate to satisfy rate stability concerns.

70. A bill-limiter provision targeting interruptible customers currently taking service on schedules which are slated for cancellation should be adopted based on the mechanism proposed by Edison but with percentage increases of 15% and 30% for 1993 and 1994 respectively.

71. The Commission should not at this time adopt measures designed to create a pool of customers for interruptible bidding programs.

72. Edison's proposal to refine the criteria for calling interruptions should be adopted.

73. Edison should be directed to include in its next GRC filing an analysis of whether broadened interruption criteria, including an economic criterion, should be adopted in that proceeding.

74. The design and use of the 37 park sample of mobilehome parks is appropriate.

75. Edison's diversity service study should be used as the basis for the adopted diversity adjustment.

76. Edison's cost of service service study should be used as the basis for the cost of service discount because it provides the most reliable estimate of the cost of service discount.

77. Edison's loss service study should be used until a service study of losses in DMS-2 parks is completed.

78. A DMS-2 Discount of $0.17 based on a diversity adjustment of $0.04, a cost of service discount of $0.18, and a loss factor adjustment of $0.03 should be adopted.

79. For its next GRC, Edison should address the need for a method of measuring costs of service to better ensure that PU Code § 739.5(a) requirements are met over the rate case cycle.

80. PU Code § 739.5(a) does not preclude Edison from fashioning reasonable and necessary minimum charge provisions.

81. Edison's BREC provision should be continued and the MAR provision should be implemented.

82. WMA's Alternative 2 cannot be adopted under PU Code § 739.5(a).

83. This decision should become effective today, so that the revised rates will become effective June 7, 1992.

SEVENTH INTERIM ORDER

IT IS ORDERED that:

1. Southern California Edison Company (Edison) shall, on or before June 5, 1992, file with this Commission revised tariff sheets which incorporate the rates set forth in Appendix C to this decision and which make other revisions as necessary to comply with this interim order and file revised contracts to implement the revised terms of Schedule TOU-8-CR-1 and the Spot-Pricing Amendment Energy Charge.

2. The revised tariff pages shall become effective June 7, 1992 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

3. Edison's supplemental revenue requirement increase request for high-cost meters is dismissed.

4. Edison's proposed Schedule DMS-3 is adopted without the 75% occupancy requirement.

5. Edison shall monitor developments in marginal costing, including any that may occur in the current Pacific Gas and Electric Company general rate case (GRC), and proceed with implementation of all appropriate and cost-effective marginal cost methodology refinements for its next GRC.

6. Edison shall monitor its real-time pricing program and similar programs of other utilities, and include in its next GRC filing a showing on whether its real-time pricing program should be extended to additional customer classes.

7. Edison shall service study and report in its next GRC filing on whether Schedule TOU-8-CR-1 should be continued. As part of that service study, Edison shall evaluate whether the new affidavit requirement remains sufficient to ensure that the load on this schedule is truly incremental.

8. Edison shall include in its next GRC filing an analysis of whether total facilities charges for Schedule LS-1 should be frozen, with recovery of differences between the actual installation costs and the facilities allowance from applicants requesting new streetlights. Edison shall provide an opportunity for customers or their representatives to provide input to the analysis.

9. Edison shall report in its next GRC filing on the outcome of efforts undertaken with street light customers to evaluate options for replacing series circuits.

10. Edison shall present a more complete analysis of street light maintenance response times in its next GRC filing. As part of that presentation, Edison shall address whether workable tariff rules governing response times are appropriate. Edison shall provide an opportunity for customers or their representatives to provide input to the analysis.

11. Edison shall include in its next GRC filing an analysis of whether broadened criteria for calling interruptions, including an economic criterion, should be adopted in that proceeding.

12. For its next GRC filing Edison shall service study and report on the need for a method of measuring costs of service that ensures that Public Utilities Code § 739.5(a) requirements are met over the rate case cycle.

This order is effective today.

Dated June 3, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
Commissioners

I CERTIFY THAT THIS DECISION
WAS APPROVED BY THE ABOVE
COMMISSIONERS TODAY

NEAL J. SHULMAN, Executive Director

SOUTHERN CALIFORNIA EDISON COMPANY
REVENUE REQUIREMENT CONSOLIDATION
FOR RATE DESIGN PURPOSES
EFFECTIVE JANUARY 20, 1992

(Thousands Of Dollars)

Line No.			Present Rate Revenues	Revenue Change	Revenue Requirement
1.	AUTHORIZED LEVEL OF BASE RATE REVENUES (ALBRR)				
2.	Previously Authorized Rates	1/	3,943,484	---	---
3.	TY-1992 GRC, D.91-12-076	2/	0	68,468	4,011,952
4.	Post-Retirement Benefits, A.L. 913-E	3/	0	21,059	21,059
5.	Post-Retirement Benefits, A.L. 917-E-A	3/	0	25,219	25,219
6.	Palo Verde Unit 3 Deferral, D.86-10-023	4/	0	(20,201)	(20,201)
7.	ALBRR: Effective January 1, 1992		3,943,484	94,545	4,038,029
8.	Palo Verde Unit 3 Deferral		0	20,201	20,201
9.	ALBRR: Effective January 20, 1992		3,943,484	114,746	4,058,230
10.	ENERGY COST ADJUSTMENT CLAUSE (ECAC)				
11.	Fuel and Purchased Power		3,026,600	135,186	3,161,786
12.	Balancing Account		260,727	(269,033)	(8,306)
13.	Coolwater, D.91-10-030	5/	0	26,295	26,295
14.	Subtotal ECAC Rate Revenues		3,287,327	(107,552)	3,179,775
15.	ELECTRIC REVENUE ADJUSTMENT BILLING FACTOR (ERABF)				
16.	Balancing Account		4,251	108,319	112,570
17.	Palo Verde Unit 1		51,720	230	51,950
18.	Palo Verde Unit 2		53,137	(235)	52,902
19.	Palo Verde Unit 3		0	50,594	50,594
20.	Off-System Sales		(48,886)	16,905	(31,981)
21.	Subtotal ERABF Rate Revenues		60,222	175,813	236,035
22.	MAJOR ADDITIONS ADJUSTMENT CLAUSE (MAAC)				
23.	SONGS 2 and 3 Pre-COD		0	0	0
24.	SONGS 2 and 3 Post-COD		32,591	(32,591)	0
25.	D.C. Expansion		11,336	0	11,336
26.	Subtotal MAAC Rate Revenues		43,927	(32,591)	11,336
27.	ANNUAL ENERGY RATE (AER)		0	0	0
28.	LOW-INCOME RATEPAYER ASSISTANCE (LIRA) PROGRAM		5,841	(12,057)	(6,216)
29.	TOTAL		7,340,801	138,359	7,479,160

1/ Based on January 1, 1991 authorized ALBRR ($3,937,547) and 1992 sales forecast.
2/ Includes reduction to revenue requirements adopted in 1992 Cost of Capital Proceeding D.91-11-059.
3/ These additions to ALBRR are effective for one year only per D.91-07-006 in I.90-07-037.
A.L. 913-E became effective October 18, 1991. A.L. 917-E-A became effective December 31, 1991.
4/ Included in 1992 ALBRR authorized by GRC D.91-12-076 , but is not effective until January 20, 1992.
5/ The authorized $78,886 is to be amortized over three years.

(END OF APPENDIX A)

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TABLE 1
ADOPTED REVENUE ALLOCATION

JANUARY 20, 1992, COMBINED RATE CHANGE
SOUTHERN CALIFORNIA EDISON COMPANY
(A.90-12-018 et al)

3.5% CAP ABOVE SAPC CAP FOR AG CLASS
Adopted ECAC Revenue + Adopted Base Revenue
Using TY92 GRC unit MCs, Using TY92 Load Research, Gas Price = $2.83

CUSTOMER GROUP	SALES	REVENUE AT PRESENT RATES Including LIRA, Facilities Chgs, & NonFirm Credit($M) At 1991 Rate Level	At 1/20/92 Rate Level	ALLOCATED REV @PRESENT RATES Excluding LIRA, Facilities Chgs, & NonFirm Credit ($M) At 1991 Rate Level	At 1/20/92 Rate Level	MARGINAL COST REVENUE ($M)	100% EPMC REVENUE ALLOCATION Excluding LIRA, Facilities Chgs, & NonFirm Credit ($M)	CAPPED REVENUE ALLOCATION Excluding LIRA, Facil., & NonFirm Credit ($M)	Including LIRA, Facil., & NonFirm Credit ($M)	PERCENT CHANGE FROM REVENUE AT PRESENT RATES Excluding LIRA, Facilities Chgs, & NonFirm Credit Vs. 1991 Rate Level	Vs. 1/20/92 Rate Level
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
DOMESTIC	22,269	2,610,411	2,678,739	2,636,385	2,708,854	1,897,403	2,740,234	2,746,202	2,680,187	4.2%	1.4%
LIGHTING - SMP:											
GS-1, GS-1-APS, GS-1-PG	4,338	555,474	570,613	553,847	569,680	400,010	577,696	578,954	569,742	4.5%	1.6%
TC-1	155	17,105	17,569	17,042	17,530	8,847	12,777	12,805	12,625	-24.9%	-27.0%
TOTAL SMALL POWER	4,492	572,579	588,181	570,889	587,210	408,857	590,473	591,759	582,367	3.7%	0.8%
GS-2, GS-2-APS, S(GS-2)	20,278	2,172,284	2,239,955	2,160,445	2,231,289	1,571,634	2,269,757	2,274,701	2,243,181	5.3%	1.9%
TOU-GS	52	6,015	6,203	5,817	6,012	3,826	5,526	5,538	5,625	-4.8%	-7.9%
TOTAL MEDIUM POWER	20,331	2,178,299	2,246,158	2,166,262	2,237,302	1,575,460	2,275,283	2,280,238	2,248,806	5.3%	1.9%
TOTAL LIGHTING - SMP	24,823	2,750,878	2,834,339	2,737,151	2,824,511	1,984,317	2,865,755	2,871,997	2,831,173	4.9%	1.7%
LARGE POWER:											
0-2 kV	7,294	720,688	714,002	729,674	724,132	473,812	684,280	685,770	678,844	-6.0%	-5.3%
2-50 kV	7,185	595,422	609,843	625,986	641,415	420,995	608,002	609,326	602,994	-2.7%	-5.0%
50 + kV	6,390	366,958	346,247	441,547	421,766	276,899	399,899	400,770	397,286	-9.2%	-5.0%
TOTAL	20,868	1,683,067	1,670,092	1,797,206	1,787,313	1,171,706	1,692,181	1,695,866	1,679,125	-5.6%	-5.1%
AGRICULTURE & PUMPING:											
PA-1	1,093	110,579	112,659	110,868	113,124	90,392	130,544	116,975	114,940	5.5%	3.4%
PA-2	543	51,061	52,016	51,087	52,129	36,239	20,521	52,450	51,775	2.7%	0.6%
TOU-ALMP-2	171	16,945	17,264	16,990	17,336	14,209	0	17,926	17,606	5.5%	3.4%
TOU-PA-5	34	2,940	2,996	2,939	3,004	1,923	0	2,781	2,789	-5.4%	-7.4%
AG-TOU except TOU-PA-5	371	33,869	34,495	33,851	34,536	24,476	38,126	35,428	34,829	4.7%	2.6%
TOTAL AG & PUMPING	2,212	215,394	219,430	215,735	220,129	167,239	241,526	225,560	221,939	4.6%	2.5%
STREET & AREA LIGHTING	470	69,031	62,167	36,501	29,637	22,414	32,371	32,442	66,707	-11.1%	9.5%
SPECIAL CONTRACTS	208	12,019	14,792						11,984	---	---
TOTAL	70,850	7,340,801	7,479,559	7,422,979	7,570,445	5,243,079	7,572,067	7,572,067	7,479,130	2.0%	0.0%

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100% EPMC AND CAPPED EPMC

CUSTOMER GROUP	SALES (GWH)	PRESENT RATE: W/ LIRA ($M): (adjusted fo: nonfirm cred: if TY88-type:	ADJUST PRES RATE REVENUE W/O LIRA ($M)	LESS: PRESENT NON-ALLOCATED REVENUE ($M)	ALLOCATED PRESENT RATE REVENUES ($M)	NET REVENUE REQUIREMENT ($M)	MARGINAL COST REVENUE ($M)	MARGINAL COST REVENUE (%)	NET 100% EPMC REVENUE ALLOCATION ($M)	ALLOCATE INTERRUPT AND APS CREDITS ($M)	100% EPMC REVENUE ALLOCATION ($M)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
DOMESTIC	22,269	2,610,411	2,624,295	(12,090.1)	2,636,385		1,897,403	36.19%	2,688,102	52,131.3	2,740,234
LIGHTING -SMP:											
GS-1, GS-1-APS, GS-1-PG	4,338	555,474	553,696	(151.5)	553,847		400,010	7.63%	566,706	10,990.3	577,696
TC-1	155	17,105	17,042	0.0	17,042		8,847	0.17%	12,534	243.1	12,777
TOTAL SMALL POWER	4,492	572,579	570,737	(151.5)	570,889		408,857	7.80%	579,239	11,233.4	590,473
GS-2, GS-2-APS, S(GS-2)	20,278	2,172,284	2,163,970	3,525.0	2,160,445		1,571,634	29.98%	2,226,576	43,180.8	2,269,757
TOU-GS	52	6,015	5,994	177.0	5,817		3,826	0.07%	5,420	105.1	5,526
TOTAL MEDIUM POWER	20,331	2,178,299	2,169,964	3,702.0	2,166,262		1,575,460	30.05%	2,231,997	43,285.9	2,275,283
TOTAL L-SMP	24,823	2,750,878	2,740,701	3,550.5	2,737,151		1,984,317	37.85%	2,811,236	54,519.3	2,865,755
LARGE POWER:											
0-2 kV	7,294	720,688	717,697	(11,977.0)	729,674		473,812	9.04%	671,262	13,018.0	684,280
2-50 kV	7,185	595,422	592,476	(33,509.7)	625,986		420,995	8.03%	596,435	11,566.9	608,002
50 + kV	6,390	366,958	364,338	(77,208.4)	441,547		276,899	5.28%	392,291	7,607.8	399,899
TOTAL	20,868	1,683,067	1,674,511	(122,695.1)	1,797,206		1,171,706	22.35%	1,659,988	32,192.7	1,692,181
AG & PUMPING:											
PA-1	1,093	110,579	110,130	(737.9)	110,868		90,392	1.72%	128,061	2,483.5	130,544
TOU-ALMP-2	171	16,945	16,875	(115.5)	16,990		14,209	0.27%	20,130	390.4	20,521
TOU-PA-5	118	10,794	10,745	0.0						0.0	
AG-TOU except TOU-PA-5	286	26,016	25,898	(146.3)						725.3	
TOTAL AG-TOU	405	36,809	36,643	(146.3)	36,790		26,399	0.50%	37,400	725.3	38,126
PA-2	543	51,061	50,839	(248.3)	51,087		36,239	0.69%	51,340	995.7	52,336
TOTAL AG & PUMPING	2,212	215,394	214,487	(1,248.0)	215,735		167,239	3.19%	236,931	4,594.9	241,526
ST & AREA LGT	470	69,031	69,031	32,529.7	36,501		22,414	0.43%	31,755	615.8	32,371
TOTAL	70,641	7,328,782	7,323,026	(99,953.0)	7,422,979	7,428,013	5,243,079	100.00%	7,428,013	144,054.1	7,572,067
						149,088 2.0085%					

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100% EPMC AND CAPPED EPMC

CUSTOMER GROUP	CHANGE FROM PRESENT RATE REVENUES W/O LIRA ($M)	(%)	CAP: (SAPC + 5.0%)= 7.01% FLOOR: -100%	CAPPED REVENUE ALLOCATION W/O DEFICIENCY ($M)	ADJUSTMENT DUE TO CAPPING ($M)	MARGINAL COST REVENUE TO ALLOCATE DEFICIENCY ($M)	100% EPMC ALLOCATION OF DEFICIENCY ($M)	CAPPED REVENUE ALLOCATION W/O LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/O LIRA ($M)	(%)
	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
			Cap, Agric.:	5.51%						
DOMESTIC	103,848	4.0%		2,740,234	0	1,897,403	(5,968)	2,746,202	109,817	4.2%
LIGHTING -SMP:										
GS-1, GS-1-APS, GS-1-PG	23,849	4.3%		577,696	0	400,010	(1,258)	578,954	25,107	4.5%
TC-1	(4,265)	-25.0%		12,777	0	8,847	(28)	12,805	(4,237)	-24.9%
TOTAL SMALL POWER	19,584	3.4%		590,473	0	408,857	(1,286)	591,759	20,870	3.7%
GS-2, GS-2-APS, S(GS-2)	109,313	5.1%		2,269,757	0	1,571,634	(4,944)	2,274,701	114,256	5.3%
TOU-GS	(292)	-4.9%		5,526	0	3,826	(12)	5,538	(279)	-4.8%
TOTAL MEDIUM POWER	109,021	5.0%		2,275,283	0	1,575,460	(4,956)	2,280,238	113,977	5.3%
TOTAL L-SMP	128,605	4.7%		2,865,755	0	1,984,317	(6,242)	2,871,997	134,847	4.9%
LARGE POWER:										
0-2 kV	(45,394)	-6.3%		684,280	0	473,812	(1,490)	685,770	(43,904)	-6.0%
2-50 kV	(17,984)	-3.0%		608,002	0	420,995	(1,324)	609,326	(16,659)	-2.7%
50 + kV	(41,648)	-11.4%		399,899	0	276,899	(871)	400,770	(40,777)	-9.2%
TOTAL	(105,026)	-6.3%		1,692,181	0	1,171,706	(3,686)	1,695,866	(101,340)	-5.6%
AG & PUMPING:										
PA-1	19,676	17.9%		116,975	(13,569)	0	0	116,975	6,107	5.5%
TOU-ALMP-2	3,531	20.9%		17,926	(2,595)	0	0	17,926	936	5.5%
TOU-PA-5										
AG-TOU except TOU-PA-5										
TOTAL AG-TOU	1,336	3.6%		38,126	0	26,399	(83)	38,209	1,419	3.9%
PA-2	1,249	2.5%		52,336	0	36,239	(114)	52,450	1,363	2.7%
TOTAL AG & PUMPING	25,791	12.0%		225,363	(16,163)	62,638	(197)	225,560	9,825	4.6%
ST & AREA LGT	(4,130)	-6.0%		32,371	0	22,414	(71)	32,442	(4,060)	-11.1%
TOTAL	149,088	2.0%		7,555,904	(16,163)	5,138,478	(16,163)	7,572,067	149,088	2.0%

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100% EPMC AND CAPPED EPMC CUSTOMER GROUP	CAP: (SAPC + 5.0%)= 7.01% FLOOR: -100%	CAPPED REVENUE ALLOCATION W/O DEFICIENCY ($M)	ADJUSTMENT DUE TO CAPPING ($M)	MARGINAL COST REVENUE TO ALLOCATE DEFICIENCY ($M)	100% EPMC ALLOCATION OF DEFICIENCY ($M)	ADJUSTED REV ALLOC W/NON-ALLOC W/O LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/O LIRA ($M)	CHANGE FROM PRESENT RATE REVENUES W/O LIRA (%)	ADD: LIRA ($M)	REVENUE ALLOCATION W/ LIRA ($M)	CHANGE FRO RATE RE W/ L ($M)
	(v)	(w)	(x)	(y)	(z)	(aa)	(bb)	(cc)	(dd)	(ee)	(ff)
DOMESTIC		2,746,202	0	1,897,403	(0)	2,746,202	109,817	4.2%	(17,900.0)	2,728,302	117,891
LIGHTING -SMP:											
GS-1, GS-1-APS, GS-1-PG		578,954	0	400,010	(0)	578,954	25,107	4.5%	1,041.0	579,995	24,521
TC-1		12,805	0	8,847	(0)	12,805	(4,237)	-24.9%	37.1	12,842	(4,263)
TOTAL SMALL POWER		591,759	0	408,857	(0)	591,759	20,870	3.7%	1,078.1	592,837	20,258
GS-2, GS-2-APS, S(GS-2)		2,274,701	0	1,571,634	(0)	2,278,047	113,772	5.3%	4,866.8	2,282,914	110,630
TOU-GS		5,538	0	3,826	(0)	5,709	(286)	-4.9%	12.5	5,722	(294)
TOTAL MEDIUM POWER		2,280,238	(0)	1,575,460	(0)	2,283,757	113,486	5.2%	4,879.3	2,288,636	110,337
TOTAL L-SMP		2,871,997	(0)	1,984,317	(0)	2,875,515	134,356	4.9%	5,957.4	2,881,473	130,594
LARGE POWER:											
0-2 kV		685,770	0	473,812	(0)	688,872	(44,501)	-6.1%	1,750.5	690,622	(30,065)
2-50 kV		609,326	0	420,995	(0)	611,616	(16,158)	-2.6%	1,724.3	613,340	17,918
50 + kV		400,770	0	276,899	(0)	402,274	(41,104)	-9.3%	1,533.6	403,808	36,850
TOTAL		1,695,866	0	1,171,706	(0)	1,702,761	(101,763)	-5.7%	5,008.4	1,707,770	24,702
AG & PUMPING:											
PA-1		116,975	0	0	0	116,975	6,107	5.5%	262.4	117,238	6,659
TOU-ALMP-2		17,926	0	0	0	17,926	936	5.5%	41.1	17,967	1,022
TOU-PA-5											
AG-TOU except TOU-PA-5											
TOTAL AG-TOU		38,209	0	26,399	(0)	38,245	1,329	3.6%	97.1	38,343	1,533
PA-2		52,450	0	36,239	(0)	52,549	1,344	2.6%	130.2	52,679	1,618
TOTAL AG & PUMPING		225,560	0	62,638	(0)	225,695	9,716	4.5%	530.8	226,226	10,832
ST & AREA LGT		32,442	0	22,414	(0)	67,322	(1,709)	-4.7%	0.0	67,322	(1,709)
TOTAL		7,572,067	(0)	5,138,478	(0)	7,617,496	150,417	2.0%	(6,403)	7,611,093	282,311

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CACO/pwf

100% EPMC AND CAPPED EPMC

CUSTOMER GROUP	% PRESENT VENUES IRA (%)	DISTANCE TO EPMC REVENUE ALLOCATION W/O LIRA ($M)	DISTANCE TO EPMC REVENUE ALLOCATION W/O LIRA (%)	100% EPMC AVERAGE RATE W/O LIRA (c/kWh)	PROPOSED AVERAGE RATE W/O LIRA (c/kWh)	PROPOSED AVERAGE RATE W/ LIRA (c/kWh)
	(gg)	(hh)	(ii)	(jj)	(kk)	(ll)
DOMESTIC	4.5%	(5,968)	-0.22%	12.31	12.33	12.25
LIGHTING -SMP:						
GS-1, GS-1-APS, GS-1-PG	4.4%	(1,258)	-0.22%	13.32	13.35	13.37
TC-1	-24.9%	(28)	-0.22%	8.27	8.29	8.31
TOTAL SMALL POWER	3.5%	(1,286)	-0.22%	13.14	13.17	13.20
GS-2, GS-2-APS, S(GS-2)	5.1%	(8,290)	-0.36%	11.19	11.23	11.26
TOU-GS	-4.9%	(184)	-3.22%	10.61	10.96	10.98
TOTAL MEDIUM POWER	5.1%	(8,474)	-0.37%	11.19	11.23	11.26
TOTAL L-SMP	4.7%	(9,760)	-0.34%	11.54	11.58	11.61
LARGE POWER:						
0-2 kV	-4.2%	(4,592)	-0.67%	9.38	9.44	9.47
2-50 kV	3.0%	(3,613)	-0.59%	8.46	8.51	8.54
50 + kV	10.0%	(2,375)	-0.59%	6.26	6.30	6.32
TOTAL	1.5%	(10,581)	-0.62%	8.11	8.16	8.18
AG & PUMPING:						
PA-1	6.0%	13,569	11.60%	11.94	10.70	10.72
TOU-ALMP-2	6.0%	2,595	14.47%	11.99	10.47	10.49
TOU-PA-5						
AG-TOU except TOU-PA-5						
TOTAL AG-TOU	4.2%	(120)	-0.31%	9.42	9.45	9.48
PA-2	3.2%	(213)	-0.40%	9.65	9.69	9.71
TOTAL AG & PUMPING	5.0%	15,831	7.01%	10.92	10.21	10.23
ST & AREA LGT	-2.5%	(34,951)	-51.92%	6.88	14.31	14.31
TOTAL	3.9%	(45,429)	-0.60%	10.72	10.78	10.77

(END OF APPENDIX B)

APPENDIX C

TABLE 2
REVISED 06/04/92
SUMMARY OF PRESENT AND ADOPTED RATE LEVELS

Adopted 1992 Combined Rate Change
ADOPTED REVENUES
(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHED	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
1.	D	Minimum Charge (¢/day)	10.00	10.00	11.50	11.50
2.						
3.		Energy Charge (¢/kWh):				
4.		Baseline	10.098	10.098	10.848	10.848
5.		Non-Baseline	14.057	14.057	14.427	14.427
6.						
7.						
8.	TOU-D-1	Minimum Charge (¢/day)	10.00	10.00	11.50	11.50
9.		Meter Charge (¢/day)	15.00	15.00	12.00	12.00
10.						
11.		Energy Charge (¢/kWh):				
12.		On-peak	50.488	-	41.190	0.000
13.		Mid-peak	19.458	15.807	0.000	11.912
14.		Off-peak	7.309	7.309	10.352	10.419
15.						
16.		Baseline Credit:	3.96	3.96	3.58	3.58
17.						
18.						
19.						
20.	TOU-D-2	Customer Charge (¢/day)	0.00	0.00	25.00	25.00
21.		Meter Charge (¢/day)	0.00	0.00	12.00	12.00
22.						
23.		Energy Charge (¢/kWh):				
24.		On-peak	0.000	-	33.946	0.000
25.		Mid-peak	0.000	0.000	0.000	8.546
26.		Off-peak	0.000	0.000	7.192	7.251
27.						
28.		Baseline Credit:	0.00	0.00	0.00	0.00
29.						
30.						
31.						
32.	D-LI	Minimum Charge (¢/day)	8.50	8.50	9.80	9.80
33.						
34.		Energy Charge (¢/kWh):				
35.		Baseline	8.583	8.583	9.220	9.220
36.		Non-Baseline	11.948	11.948	12.263	12.263

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SUMMARY OF PRESENT AND ADOPTED RATE LEVELS

Adopted 1992 Combined Rate Change
ADOPTED REVENUES
(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHED	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
37.	GS-1	Customer Charge (¢/day)	30.00	30.00	40.00	40.00
38.						
39.		Energy Charge (¢/kWh):	11.802	11.802	12.053	12.053
40.						
41.						
42.	GS-2	Customer Charge ($/Mo.)	36.25	36.25	41.80	41.80
43.						
44.		Energy Charge (¢/kWh):				
45.		First 300 kWh/kW	9.578	9.578	9.987	9.987
46.		Excess kWh	5.000	5.000	5.000	5.000
47.						
48.		Time Related Demand Charge ($/kW):	10.00	3.15	7.20	0.00
49.		Non-Time Related Demand Charge ($/kW):			3.65	3.65
50.						
51.	TC-1	Customer Charge (¢/day)	30.00	30.00	26.00	26.00
52.						
53.		Energy Charge (¢/kWh):	10.245	10.245	7.607	7.607
54.						
55.						
56.	TOU-GS	Customer Charge ($/Mo.)	36.25	36.25	41.75	41.75
57.		Meter Charge ($/Mo.)	7.00	7.00	0.00	0.00
58.						
59.		Energy Charge (¢/kWh):				
60.		On-peak	14.023	-	17.709	-
61.		Mid-peak	11.246	12.590	7.803	9.235
62.		Off-peak	5.000	5.000	5.000	5.000
63.						
64.		Demand Charge ($/kW):				
65.						
66.		Non-Time Related:	3.15	3.15	3.65	3.65
67.						
68.		Time Related:				
69.		On-peak	13.70	-	14.40	-
70.		Mid-peak	2.10	0.00	2.20	0.00
71.		Off-peak	0.00	0.00	0.00	0.00

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TABLE 2
REVISED 06/04/92
SUMMARY OF PRESENT AND ADOPTED RATE LEVELS

Adopted 1992 Combined Rate Change
ADOPTED REVENUES
(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHED	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
72.	TOU-8-SEC	Customer Charge ($/Mo.)	287.00	287.00	387.20	387.20
73.						
74.		Energy Charge (c/kWh):				
75.		On-peak	11.531	-	14.675	-
76.		Mid-peak	9.247	10.352	6.900	8.199
77.		Off-peak	5.000	5.000	4.342	4.622
78.						
79.		Demand Charge ($/kW):				
80.						
81.		Non-Time Related	3.10	3.10	3.65	3.65
82.						
83.		Time Related:				
84.		On-peak	15.20	-	15.80	-
85.		Mid-peak	2.40	0.00	2.50	0.00
86.		Off-peak	0.00	0.00	0.00	0.00
87.						
88.		Rate Limiters (c/kWh):				
89.		Average Summer Rate Limiter:	15.77		17.76	
90.		On-peak Rate Limiter:	94.54		110.30	
91.						
92.						
93.	TOU-8-PRI	Customer Charge ($/Mo.)	282.40	282.40	359.45	359.45
94.						
95.		Energy Charge (c/kWh):				
96.		On-peak	10.551	-	14.564	-
97.		Mid-peak	8.460	9.505	6.879	8.123
98.		Off-peak	5.000	5.000	4.287	4.561
99.						
100.		Demand Charge ($/kW):				
101.						
102.		Non-Time Related	2.20	2.20	3.15	3.15
103.						
104.		Time Related:				
105.		On-peak	14.65	-	15.75	-
106.		Mid-peak	2.20	0.00	2.35	0.00
107.		Off-peak	0.00	0.00	0.00	0.00
108.						
109.		Rate Limiters (c/kWh):				
110.		Average Summer Rate Limiter:	15.77		17.76	
111.		On-peak Rate Limiter:	91.88		107.24	
112.						
113.						
114.	TOU-8-SUB	Customer Charge ($/Mo.)	279.25	279.25	365.50	365.50
115.						
116.		Energy Charge (c/kWh):				
117.		On-peak	8.293	-	10.150	-
118.		Mid-peak	6.650	7.472	5.055	6.024
119.		Off-peak	5.000	5.000	4.223	4.488
120.						
121.		Demand Charge ($/kW):				
122.						
123.		Non-Time Related	0.25	0.25	0.40	0.40
124.						
125.		Time Related:				
126.		On-peak	12.55	-	13.90	-
127.		Mid-peak	1.95	0.00	2.15	0.00
128.		Off-peak	0.00	0.00	0.00	0.00
129.						
130.		Rate Limiters (c/kWh):				
131.		On-peak Rate Limiter:	69.07		90.31	

APPENDIX C

TABLE 2
REVISED 06/04/92
SUMMARY OF PRESENT AND ADOPTED RATE LEVELS

Adopted 1992 Combined Rate Change
ADOPTED REVENUES
(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHED	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
132.	PA-1	Customer Charge ($/Mo.)	11.40	11.40	12.55	12.55
133.						
134.		Energy Charge (c/kWh):	9.107	9.107	9.502	9.502
135.						
136.		Connected Load				
137.		Charge ($/Hp)	1.15	1.15	1.35	1.35
138.						
139.						
140.	PA-2	Customer Charge ($/Mo.)	22.85	22.85	23.85	23.85
141.						
142.		Energy Charge (c/kWh):				
143.		First 300 kWh/kW	9.893	9.893	10.287	10.287
144.		Excess kWh	5.000	5.000	5.000	5.000
145.						
146.		Demand Charge ($/kW):	8.15	1.30	7.05	0.00
147.		Non-time Related Demand Charge ($/kw)			1.45	1.45
148.						
149.	TOU-ALMP-2	Customer Charge ($/Mo.)	11.40	11.40	12.55	12.55
150.						
151.		Energy Charge (c/kWh):				
152.		On-peak	22.762	-	24.005	-
153.		Mid-peak	-	22.486	-	23.714
154.		Off-peak	7.345	7.865	7.747	8.295
155.						
156.						
157.	TOU-PA-1	Customer Charge ($/Mo.)	11.40	11.40	12.55	12.55
158						
159.		Energy Charge (c/kWh):				
160.		On-peak	10.153	-	9.817	-
161.		Mid-peak	-	9.804	-	9.482
162.		Off-peak	6.283	6.412	6.077	6.201
163.						
164.		KVA Charge ($/KVA)	3.15	3.15	3.60	3.60
165.						
166.	TOU-PA-A	Customer Charge ($/Mo.)	34.25	34.25	35.85	35.85
167.		Meter Charge ($/Mo.)	6.00	6.00	0.00	0.00
168.						
169.		Energy Charge (c/kWh):				
170.		On-peak	14.449	-	17.582	-
171.		Mid-peak	11.587	12.972	11.310	13.279
172.		Off-peak	5.000	5.000	5.000	5.000
173.						
174.		Connected Load				
175.		Charge ($/Hp)	1.15	1.15	1.35	1.35
176.						
177.						
178.	TOU-PA-B	Customer Charge ($/Mo.)	34.25	34.25	35.85	35.85
179.		Meter Charge ($/Mo.)	6.00	6.00	0.00	0.00
180.						
181.		Energy Charge (c/kWh):				
182.		On-peak	14.426	-	14.428	-
183.		Mid-peak	11.569	12.952	9.282	10.897
184.		Off-peak	5.000	5.000	5.000	5.000
185.						
186.		Demand Charge ($/kW):				
187.						
188.		Non-Time Related	1.30	1.30	1.60	1.60
189.						
190.		Time Related:				
191.		On-peak	6.80	-	7.80	-
192.		Mid-peak	0.00	0.00	0.00	0.00
193.		Off-peak	0.00	0.00	0.00	0.00

APPENDIX C

TABLE 2
REVISED 06/04/92
SUMMARY OF PRESENT AND ADOPTED RATE LEVELS

Adopted 1992 Combined Rate Change
ADOPTED REVENUES
(Excludes PUC Reimbursement Fee and LIS)

Line No.	Rate Sched	Components	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter
194.	TOU-PA-3-A	Customer Charge ($/Mo.)	34.25	34.25		
195.		Meter Charge ($/Mo.)	6.00	6.00		
196.						
197.		Energy Charge (c/kWh):				
198.		On-peak	14.706	-	CANCELLED 6/7/92	
199.		Mid-peak	11.793	13.203		
200.		Off-peak	5.000	5.000		
201.		Connected Load				
202.		Charge ($/Hp)	1.15	1.15		
203.						
204.	TOU-PA-3-B	Customer Charge ($/Mo.)	34.25	34.25		
205.		Meter Charge ($/Mo.)	6.00	6.00		
206.						
207.		Energy Charge (c/kWh):				
208.		On-peak	15.690	-		
209.		Mid-peak	12.583	14.087		
210.		Off-peak	5.000	5.000		
211.		Demand Charge ($/kW):			CANCELLED 6/7/92	
212.		Non-Time Related	1.30	1.30		
213.		Time Related:				
214.		On-peak	6.80	-		
215.		Mid-peak	0.00	0.00		
216.		Off-peak	0.00	0.00		
217.						
218.	TOU-PA-4-A	Customer Charge ($/Mo.)	34.25	34.25	35.85	35.85
219.		Meter Charge ($/Mo.)	6.00	6.00	0.00	0.00
220.						
221.		Energy Charge (c/kWh):				
222.		On-peak	14.666	-	18.113	-
223.		Mid-peak	11.762	13.168	11.652	13.680
224.		Off-peak	5.000	5.000	5.000	5.000
225.		Connected Load				
226.		Charge ($/Hp)	1.15	1.15	1.35	1.35
227.						
228.	TOU-PA-4-B	Customer Charge ($/Mo.)	34.25	34.25	35.85	35.85
229.		Meter Charge ($/Mo.)	6.00	6.00	0.00	0.00
230.						
231.		Energy Charge (c/kWh):				
232.		On-peak	15.633	-	18.809	-
233.		Mid-peak	12.537	14.035	12.100	14.206
234.		Off-peak	5.000	5.000	5.000	5.000
235.		Demand Charge ($/kW):				
236.		Non-Time Related	1.30	1.30	1.60	1.60
237.		Time Related:				
238.		On-peak	6.80	-	7.80	-
239.		Mid-peak	0.00	0.00	0.00	0.00
240.		Off-peak	0.00	0.00	0.00	0.00
241.						
242.	TOU-PA-5	Customer Charge ($/Mo.)	22.85	22.85	35.85	35.85
243.		Meter Charge ($/Mo.)	6.00	6.00	0.00	0.00
244.		Minimum Charge ($/Mo.)	26.15	11.15	24.15	7.70
245.						
246.		Energy Charge (c/kWh):				
247.		On-peak	8.756	-	10.711	-
248.		Mid-peak	7.022	7.861	6.887	8.087
249.		Off-peak	6.435	6.495	5.716	6.584
250.		Demand Charge ($/kW):				
251.		Non-Time Related	1.30	1.30	1.60	1.60
252.		Time-Related:				
253.		On-peak	6.85	-	7.80	-
254.		Mid-peak	0.00	0.00	0.00	0.00
255.		Off-peak	0.00	0.00	0.00	0.00

APPENDIX C

TABLE 2
REVISED 06/04/92
SUMMARY OF PRESENT AND ADOPTED RATE LEVELS
ADOPTED REVENUES
Adopted JUNE, 1992 Combined Rate Change
(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
246.	I-5-A SEC:	Customer Charge ($/Mo.)	287.00	287.00	387.20	387.20
247.						
248.		Energy Charge (c/kWh):				
249.		On-peak	10.031	-	12.030	-
250.		Mid-peak	7.747	8.852	4.255	5.554
251.		Off-peak	2.500	2.500	2.550	2.939
252.						
253.		Demand Charge ($/kW):				
254.		Non-Time Related	3.10	3.10	3.65	3.65
255.						
256.		Time Related:				
257.		On-peak	15.20	-	15.80	-
258.		Mid-peak	2.40	0.00	2.50	0.00
259.		Off-peak	0.00	0.00	0.00	0.00
260.						
261.	I-5-A PRI:	Customer Charge ($/Mo.)	282.40	282.40	359.45	359.45
262.						
263.		Energy Charge (c/kWh):				
264.		On-peak	9.051	-	11.952	-
265.		Mid-peak	6.960	8.005	4.267	5.511
266.		Off-peak	2.500	2.500	2.475	2.854
267.						
268.		Demand Charge ($/kW):				
269.		Non-Time Related	2.20	2.20	3.15	3.15
270.						
271.		Time Related:				
272.		On-peak	14.65	-	15.75	-
273.		Mid-peak	2.20	0.00	2.35	0.00
274.		Off-peak	0.00	0.00	0.00	0.00
275.						
276.	I-5-A SUB:	Customer Charge ($/Mo.)	279.25	279.25	365.50	365.50
277.						
278.		Energy Charge (c/kWh):				
279.		On-peak	6.793	-	7.578	-
280.		Mid-peak	5.150	5.972	2.483	3.452
281.		Off-peak	2.500	2.500	2.386	2.752
282.						
283.		Demand Charge ($/kW):				
284.		Non-Time Related	0.25	0.25	0.40	0.40
285.						
286.		Time Related:				
287.		On-peak	12.55	-	13.90	-
288.		Mid-peak	1.95	0.00	2.15	0.00
289.		Off-peak	0.00	0.00	0.00	0.00
290.						
291.	I-5-B SEC:	Customer Charge ($/Mo.)	287.00	287.00	387.20	387.20
292.						
293.		Energy Charge (c/kWh):				
294.		On-peak	11.531	-	13.774	-
295.		Mid-peak	9.247	10.352	5.999	7.298
296.		Off-peak	5.000	5.000	4.342	4.622
297.		Off-peak	2.500	2.500	2.550	2.939
298.						
299.		Demand Charge ($/kW):				
300.		Non-Time Related	3.10	3.10	3.65	3.65
301.						
302.		Time Related:				
303.		On-peak	15.20	-	15.80	-
304.		Mid-peak	2.40	0.00	2.50	0.00
305.		Off-peak	0.00	0.00	0.00	0.00

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ADOPTED REVENUES
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(Excludes PUC Reimbursement Fee and LIS)

Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
306.	I-5-B PRI:	Customer Charge ($/Mo.)	282.40	282.40	359.45	359.45
307.						
308.		Energy Charge (¢/kWh):				
309.		On-peak	10.551	-	13.689	-
310.		Mid-peak	8.460	9.505	6.004	7.248
311.		Off-peak	5.000	5.000	4.287	4.561
312.		Off-peak	2.500	2.500	2.475	2.854
313.						
314.		Demand Charge ($/kW):				
315.		Non-Time Related	2.20	2.20	3.15	3.15
316.						
317.		Time Related:				
318.		On-peak	14.65	-	15.75	-
319.		Mid-peak	2.20	0.00	2.35	0.00
320.		Off-peak	0.00	0.00	0.00	0.00
321.						
322.	I-5-B SUB:	Customer Charge ($/Mo.)	279.25	279.25	365.50	365.50
323.						
324.		Energy Charge (¢/kWh):				
325.		On-peak	8.293	-	9.307	-
326.		Mid-peak	6.650	7.472	4.312	5.181
327.		Off-peak	5.000	5.000	4.223	4.488
328.		Off-peak	2.500	2.500	2.386	2.752
329.						
330.		Demand Charge ($/kW):				
331.		Non-Time Related	0.25	0.25	0.40	0.40
332.						
333.		Time Related:				
334.		On-peak	12.55	-	13.90	-
335.		Mid-peak	1.95	0.00	2.15	0.00
336.		Off-peak	0.00	0.00	0.00	0.00
337.						
338.						
339.	I-6-A SEC:	Customer Charge ($/Mo.)	287.00	287.00	387.20	387.20
340.						
341.		Energy Charge (¢/kWh):				
342.		On-peak	10.833	-	13.035	-
343.		Mid-peak	8.707	9.789	6.129	7.283
344.		Off-peak	4.542	4.526	3.711	3.895
345.						
346.		Demand Charge ($/kW):				
347.		Non-Time Related	3.10	3.10	3.65	3.65
348.						
349.		Time Related:				
350.		On-peak	10.65	-	7.15	-
351.		Mid-peak	1.70	0.00	1.15	0.00
352.		Off-peak	0.00	0.00	0.00	0.00
353.						
354.	I-6-A PRI:	Customer Charge ($/Mo.)	282.40	282.40	359.45	359.45
355.						
356.		Energy Charge (¢/kWh):				
357.		On-peak	9.868	-	12.993	-
358.		Mid-peak	7.930	8.968	6.137	7.247
358.		Off-peak	4.542	4.526	3.683	3.864
359.						
360.		Demand Charge ($/kW):				
361.		Non-Time Related	2.20	2.20	3.15	3.15
362.						
363.		Time Related:				
364.		On-peak	10.25	-	7.10	-
365.		Mid-peak	1.50	0.00	1.05	0.00
366.		Off-peak	0.00	0.00	0.00	0.00

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Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE WINTER
367.	I-6-A SUB:	Customer Charge ($/Mo.)	279.25	279.25	365.50	365.50
368.						
369.		Energy Charge (c/kWh):				
370.		On-peak	7.666	-	8.915	-
371.		Mid-peak	6.169	6.977	4.440	5.291
372.		Off-peak	4.542	4.526	3.714	3.900
373.						
374.		Demand Charge ($/kW):				
375.		Non-Time Related	0.25	0.25	0.40	0.40
376.						
377.		Time Related:				
378.		On-peak	8.30	-	7.55	-
379.		Mid-peak	1.30	0.00	1.15	0.00
380.		Off-peak	0.00	0.00	0.00	0.00
381.						
382.	I-6-B SEC:	Customer Charge ($/Mo.)	287.00	287.00	N/A	N/A
383.					N/A	N/A
384.		Energy Charge (c/kWh):			N/A	N/A
385.		On-peak	10.920	-	N/A	N/A
386.		Mid-peak	8.774	9.859	N/A	N/A
387.		Off-peak	4.599	4.585	N/A	N/A
388.					N/A	N/A
389.		Demand Charge ($/kW):			N/A	N/A
390.		Non-Time Related	3.10	3.10	N/A	N/A
391.					N/A	N/A
392.		Time Related:			N/A	N/A
393.		On-peak	11.20	-	N/A	N/A
394.		Mid-peak	1.80	0.00	N/A	N/A
395.		Off-peak	0.00	0.00	N/A	N/A
396.					N/A	N/A
397.	I-6-B PRI:	Customer Charge ($/Mo.)	282.40	282.40	N/A	N/A
398.					N/A	N/A
399.		Energy Charge (c/kWh):			N/A	N/A
400.		On-peak	9.953	-	N/A	N/A
401.		Mid-peak	7.996	9.035	N/A	N/A
402.		Off-peak	4.599	4.585	N/A	N/A
403.					N/A	N/A
404.		Demand Charge ($/kW):			N/A	N/A
405.		Non-Time Related	2.20	2.20	N/A	N/A
406.					N/A	N/A
407.		Time Related:			N/A	N/A
408.		On-peak	10.80	-	N/A	N/A
409.		Mid-peak	1.60	0.00	N/A	N/A
410.		Off-peak	0.00	0.00	N/A	N/A
411.					N/A	N/A
412.	I-6-B SUB:	Customer Charge ($/Mo.)	279.25	279.25	N/A	N/A
413.					N/A	N/A
414.		Energy Charge (c/kWh):			N/A	N/A
415.		On-peak	7.744	-	N/A	N/A
416.		Mid-peak	6.228	7.038	N/A	N/A
417.		Off-peak	4.599	4.585	N/A	N/A
418.					N/A	N/A
419.		Demand Charge ($/kW):			N/A	N/A
420.		Non-Time Related	0.25	0.25	N/A	N/A
421.					N/A	N/A
422.		Time Related:			N/A	N/A
423.		On-peak	8.85	-	N/A	N/A
424.		Mid-peak	1.35	0.00	N/A	N/A
425.		Off-peak	0.00	0.00	N/A	N/A

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Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE SPRING/FALL	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE SPRING/FALL	PROPOSED RATE WINTER
426.	TOU-GS-SOP:	Customer Charge ($/Mo.)	36.25	36.25	36.25	41.75	N/A	41.75
427.		Meter Charge ($/Mo.)	7.00	7.00	7.00	N/A	N/A	N/A
428.								
429.		Energy Charge (c/kWh):						
430.		On-peak	11.111	-	-	12.514	N/A	-
431.		Mid-peak	11.111	8.425	9.266	7.771	N/A	7.936
432.		Off-peak	7.329	7.822	7.822	-	N/A	-
433.		Super Off-peak	3.500	3.500	3.500	3.500	N/A	3.500
434.								
435.		Demand Charge ($/kW):						
436.		Non-Time Related	3.15	3.15	3.15	3.65	N/A	3.65
437.								
438.		Time Related:						
439.		On-peak	39.85		-	37.95	N/A	N/A
440.		Mid-peak	1.05	0.55	0.55	1.00	N/A	0.50
441.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
442.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
443.								
444.								
445.	TOU-8-SOP-SEC:	Customer Charge ($/Mo.)	287.00	287.00	287.00	387.20	N/A	387.20
446.								
447.		Energy Charge (c/kWh):						
448.		On-peak	10.123	-	-	11.990	-	-
449.		Mid-peak	10.123	7.657	8.421	6.930	N/A	7.603
450.		Off-peak	6.661	7.109	7.109	3.500	N/A	3.500
451.		Off-peak	3.500	3.500	3.500	N/A	N/A	N/A
452.								
453.		Demand Charge ($/kW):						
454.		Non-Time Related	3.10	3.10	3.10	3.65	N/A	3.65
455.								
456.		Time Related:						
457.		On-peak	37.85	-	-	35.55	-	-
458.		Mid-peak	1.00	0.50	0.50	0.95	N/A	0.45
459.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
460.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00

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Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE SPRING/FALL	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE SPRING/FALL	PROPOSED RATE WINTER
461.	TOU-8-SOP-PRI:	Customer Charge ($/Mo.)	282.40	282.40	282.40	359.45	N/A	359.45
462.								
463.		Energy Charge (¢/kWh):						
464.		On-peak	9.062	-	-	11.888	N/A	-
465.		Mid-peak	9.062	6.873	7.559	6.875	N/A	7.544
466.		Off-peak	5.979	6.381	6.381	3.500	N/A	3.500
467.		Off-peak	3.500	3.500	3.500	N/A	N/A	N/A
468.								
469.		Demand Charge ($/kW):						
470.		Non-Time Related	2.20	2.20	2.20	3.15	N/A	3.15
471.								
472.		Time Related:						
473.		On-peak	37.25	-	-	36.25	N/A	-
474.		Mid-peak	0.95	0.50	0.50	0.90	N/A	0.50
475.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
476.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
477.								
478.	TOU-8-SOP-SUB:	Customer Charge ($/Mo.)	279.25	279.25	279.25	365.50	N/A	365.50
479.								
480.		Energy Charge (¢/kWh):						
481.		On-peak	7.974	-	-	8.913	-	-
482.		Mid-peak	7.974	6.064	6.670	5.163	N/A	5.669
483.		Off-peak	5.276	5.630	5.630	3.500	N/A	3.500
484.		Off-peak	3.500	3.500	3.500	N/A	N/A	N/A
485.								
486.		Demand Charge ($/kW):						
487.		Non-Time Related	0.25	0.25	0.25	0.40	N/A	0.40
488.								
489.		Time Related:						
490.		On-peak	35.15	-	-	31.90	N/A	-
491.		Mid-peak	0.95	0.45	0.45	0.85	N/A	0.40
492.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
493.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00

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Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE SPRING/FALL	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE SPRING/FALL	PROPOSED RATE WINTER
494.	TOU-8-SOP-I-SEC:	Customer Charge ($/Mo.)	287.00	287.00	287.00	387.20	N/A	387.20
495.								
496.		Energy Charge (c/kWh):						
497.		On-peak	9.777	-	-	11.072	N/A	-
498.		Mid-peak	9.777	7.437	8.197	6.399	N/A	7.021
499.		Off-peak	6.349	6.878	6.887	3.085	N/A	2.979
500.		Off-peak	3.343	3.343	3.343	N/A	N/A	N/A
501.								
502.		Demand Charge ($/kW):						
503.		Non-Time Related	3.10	3.10	3.10	3.65	N/A	3.65
504.								
505.		Time Related:						
506.		On-peak	27.05	-	-	16.05	N/A	-
507.		Mid-peak	0.65	0.35	0.35	0.45	N/A	0.20
508.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
509.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
510.								
511.								
512.	TOU-8-SOP-I-PRI:	Customer Charge ($/Mo.)	282.40	282.40	282.40	359.45	N/A	359.45
513.								
514.		Energy Charge (c/kWh):						
515.		On-peak	8.821	-	-	11.059	N/A	-
516.		Mid-peak	8.821	6.660	7.341	6.396	N/A	7.018
517.		Off-peak	5.771	6.157	6.166	3.125	N/A	3.029
518.		Off-peak	3.343	3.343	3.343	N/A	N/A	N/A
519.								
520.		Demand Charge ($/kW):						
521.		Non-Time Related	2.20	2.20	2.20	3.15	N/A	3.15
522.								
523.		Time Related:						
524.		On-peak	26.45	-	-	16.40	N/A	-
525.		Mid-peak	0.60	0.35	0.35	0.40	N/A	0.25
526.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
527.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00

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Line No.	RATE SCHEDULE	COMPONENTS	PRESENT RATE SUMMER	PRESENT RATE SPRING/FALL	PRESENT RATE WINTER	PROPOSED RATE SUMMER	PROPOSED RATE SPRING/FALL	PROPOSED RATE WINTER
528.	TOU-8-SOP-I-SUB:	Customer Charge ($/Mo.)	279.25	279.25	279.25	365.50	N/A	365.50
529.								
530.		Energy Charge (c/kWh):						
531.		On-peak	7.744	-	-	8.174	N/A	-
532.		Mid-peak	7.744	5.860	6.462	4.735	N/A	5.199
533.		Off-peak	5.077	5.416	5.424	3.164	N/A	3.078
534.		Off-peak	3.343	3.343	3.343	N/A	N/A	N/A
535.								
536.		Demand Charge ($/kW):						
537.		Non-Time Related	0.25	0.25	0.25	0.40	N/A	0.40
538.								
539.		Time Related:						
540.		On-peak	24.80	-	-	17.30	N/A	-
541.		Mid-peak	0.65	0.30	0.30	0.45	N/A	0.20
542.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
543.		Off-peak	0.00	0.00	0.00	0.00	N/A	0.00
544.								
545.	TOU-8-SOP-I-8-SE	Customer Charge ($/Mo.)	287.00	287.00	287.00	N/A	N/A	N/A
546.								N/A
547.		Energy Charge (c/kWh):						N/A
548.		On-peak	9.819	-	-	N/A	N/A	N/A
549.		Mid-peak	9.819	7.464	8.225	N/A	N/A	N/A
550.		Off-peak	6.387	6.906	6.914	N/A	N/A	N/A
551.		Off-peak	3.362	3.362	3.362	N/A	N/A	N/A
552.						N/A	N/A	N/A
553.		Demand Charge ($/kW):				N/A	N/A	N/A
554.		Non-Time Related	3.10	3.10	3.10	N/A	N/A	N/A
555.						N/A	N/A	N/A
556.		Time Related:				N/A	N/A	N/A
557.		On-peak	28.35	-	-	N/A	N/A	N/A
558.		Mid-peak	0.70	0.35	0.35	N/A	N/A	N/A
559.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
560.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
561.						N/A	N/A	N/A

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562.	TOU-8-SOP-1-B-PR	Customer Charge ($/Mo.)	282.40	282.40	282.40	N/A	N/A	N/A
563.						N/A	N/A	N/A
564.		Energy Charge (c/kWh):				N/A	N/A	N/A
565.		On-peak	8.851	-	-	N/A	N/A	N/A
566.		Mid-peak	8.851	6.686	7.368	N/A	N/A	N/A
567.		Off-peak	5.797	6.185	6.192	N/A	N/A	N/A
568.		Off-peak	3.362	3.362	3.362	N/A	N/A	N/A
569.						N/A	N/A	N/A
570.		Demand Charge ($/kW):				N/A	N/A	N/A
571.		Non-Time Related	2.20	2.20	2.20	N/A	N/A	N/A
572.						N/A	N/A	N/A
573.		Time Related:				N/A	N/A	N/A
574.		On-peak	27.75	-	-	N/A	N/A	N/A
575.		Mid-peak	0.65	0.35	0.35	N/A	N/A	N/A
576.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
577.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
578.						N/A	N/A	N/A
579.	TOU-8-SOP-1-B-SU	Customer Charge ($/Mo.)	279.25	279.25	279.25	N/A	N/A	N/A
560.						N/A	N/A	N/A
561.		Energy Charge (c/kWh):				N/A	N/A	N/A
562.		On-peak	7.773	-	-	N/A	N/A	N/A
563.		Mid-peak	7.773	5.885	6.488	N/A	N/A	N/A
564.		Off-peak	5.102	5.443	5.450	N/A	N/A	N/A
565.		Off-peak	3.362	3.362	3.362	N/A	N/A	N/A
566.						N/A	N/A	N/A
567.		Demand Charge ($/kW):				N/A	N/A	N/A
568.		Non-Time Related	0.25	0.25	0.25	N/A	N/A	N/A
569.						N/A	N/A	N/A
570.		Time Related:				N/A	N/A	N/A
571.		On-peak	26.15	-	-	N/A	N/A	N/A
572.		Mid-peak	0.70	0.30	0.30	N/A	N/A	N/A
573.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
574.		Off-peak	0.00	0.00	0.00	N/A	N/A	N/A
575.								

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576.	TOU-PA-SOP:	Customer Charge ($/Mo.)	34.25	-	34.25	35.15	-	35.15
577.		Meter Charge ($/Mo.)	6.00	-	6.00	N/A	-	N/A
578.								
579.		Energy Charge (c/kWh):						
580.		On-peak	10.092	-	-	10.767	-	-
581.		Off-peak	7.321	-	7.531	6.926	-	8.132
582.		Off-peak	3.500	-	3.500	3.500	-	3.500
583.								
584.		Demand Charge ($/kW):						
585.		Non-Time Related	1.30	-	1.30	1.60	-	1.60
586.								
587.		Time Related:						
588.		On-peak	37.65	-	-	38.65	-	-
589.		Off-peak	0.00	-	0.00	0.00	-	0.00
590.		Off-peak	0.00	-	0.00	0.00	-	0.00
591.								
592.	TOU-PA-SOP-I:	Customer Charge ($/Mo.)	N/A	-	N/A	35.15	-	35.15
593.		Meter Charge ($/Mo.)	N/A	-	N/A	N/A	-	N/A
594.								
595.		Energy Charge (c/kWh):						
596.		On-peak	N/A	-	-	9.872	-	-
597.		Off-peak	N/A	-	N/A	6.412	-	7.568
598.		Off-peak	N/A	-	N/A	3.096	-	2.992
599.								
600.		Demand Charge ($/kW):						
601.		Non-Time Related	N/A	-	N/A	1.60	-	1.60
602.								
603.		Time Related:						
604.		On-peak	N/A	-	-	17.50	-	-
605.		Off-peak	N/A	-	N/A	0.00	-	0.00
606.		Off-peak	N/A	-	N/A	0.00	-	0.00

TABLE 3

LS-1 A - ALL NIGHT SERVICE 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE ((1+2)*3) (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL KWH (15)
INCANDESCENT LAMPS																
103	1,000	0.03246	0.03170	35.535	2.27893	6.41824	0.40653	9.17	465	6,492	38,505	2,268	45,265	6,349	51,635	155,911
202	2,500	0.03246	0.03170	69.650	4.47131	5.87861	0.40653	10.78	235	6,370	16,414	1,146	23,939	6,230	30,169	156,526
327	4,000	0.03246	0.03170	112.815	7.23821	5.81230	0.40653	13.46	1,435	63,059	100,084	7,000	170,143	61,583	231,726	1,542,674
448	6,000	0.03246	0.03170	154.560	9.91657	6.23634	0.40653	16.56	364	21,914	27,240	1,776	50,930	21,401	72,331	675,118
MERCURY VAPOR LAMPS																
100	4,000	0.03246	0.03170	45.195	2.89974	5.23413	0.40653	8.54	568	9,995	35,676	2,776	48,446	9,765	58,211	308,649
175	7,900	0.03246	0.03170	74.529	4.78130	5.44760	0.40653	10.64	2,408	90,924	222,785	16,625	330,334	96,608	434,942	3,647,578
250	12,000	0.03246	0.03170	103.845	6.66270	6.94374	0.40653	14.01	354	14,319	29,484	1,727	45,530	13,984	59,514	441,134
400	21,000	0.03246	0.03170	163.530	10.49208	6.88385	0.40653	17.78	1,313	83,763	158,027	8,415	150,805	81,852	310,657	3,565,503
700	41,000	0.03246	0.03170	277.035	17.77457	6.01463	0.40653	24.20	43	4,640	3,104	210	7,954	4,532	12,486	142,558
1,000	55,000	0.03246	0.03170	391.575	25.12345	6.84288	0.40653	31.57	4	619	290	20	920	596	1,516	18,796
HIGH PRESSURE SODIUM																
50	4,000	0.03246	0.03170	20.818	1.28384	4.78494	0.40653	6.48	29,753	231,896	1,788,338	145,148	2,015,375	226,466	2,311,841	7,144,050
70	5,450	0.03246	0.03170	28.635	1.83722	4.78478	0.40653	7.03	165,013	1,049,939	9,474,578	604,893	12,128,103	1,297,446	13,817,549	56,781,767
100	9,500	0.03246	0.03170	40.365	2.58982	5.19283	0.40653	8.18	176,195	2,770,510	19,789,096	859,543	14,418,949	2,765,447	17,121,396	85,345,334
150	16,000	0.03246	0.03170	66.515	4.27209	5.92236	0.40653	9.80	35,359	747,163	1,855,564	148,058	2,820,785	758,733	3,568,518	24,253,257
200	22,000	0.03246	0.03170	84.078	5.44526	5.45475	0.40653	11.31	58,337	1,930,521	3,022,493	284,882	6,037,895	1,885,521	7,923,316	55,473,841
250	27,500	0.03246	0.03170	107.965	6.92832	5.46550	0.40653	12.80	8,358	351,557	540,569	48,773	940,839	343,326	1,284,225	19,830,484
400	50,000	0.03246	0.03170	167.325	10.73357	5.85535	0.40653	17.00	2,007	130,809	141,020	9,781	281,620	127,746	409,366	4,829,855
LOW PRESSURE SODIUM																
35	4,800	0.03246	0.03170	21.735	1.39452	6.43992	0.40653	8.00	1	6	74	5	87	8	95	9,261
55	8,000	0.03246	0.03170	28.580	1.65936	6.44326	0.40653	8.91	2,215	81,445	575,173	35,197	691,815	79,538	771,353	7,929,881
90	13,500	0.03246	0.03170	45.195	2.89978	7.48599	0.40653	10.79	105	1,915	9,792	532	12,243	1,874	14,117	58,115
135	22,500	0.03246	0.03170	62.790	4.02863	7.92728	0.40653	12.36	1,132	37,666	107,614	5,522	148,492	27,038	167,930	832,939
180	33,000	0.03246	0.03170	78.005	5.04896	8.23359	0.40653	13.71	0	0	0	0	0	0	0	0.000
								TOTAL ALL NIGHT	485,724	8,463,952	39,637,502	2,374,415	48,458,949	8,265,784	48,726,333	269,750,112

TABLE 3

LS-1

E - MIDNIGHT SERVICE 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL KWH (15)
INCANDESCENT LAMPS																
103	1,000	0.03349	0.03259	18.833	1.23127	6.48674	0.40653	8.12	0	0	0	0	0	0	0	0.000
202	2,500	0.03349	0.03259	36.543	2.41478	5.82041	0.40653	8.64	0	0	0	0	0	0	0	0.000
327	4,000	0.03349	0.03259	59.154	3.90890	5.81308	0.40653	10.13	0	0	0	0	0	0	0	0.000
448	6,000	0.03349	0.03259	81.043	5.35532	6.23824	0.40653	12.00	0	0	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS																
100	4,000	0.03349	0.03259	23.658	1.56336	5.23413	0.40653	7.20	0	0	0	0	0	0	0	0.000
175	7,900	0.03349	0.03259	38.874	2.58281	5.44760	0.40653	8.44	0	0	0	0	0	0	0	0.000
250	12,000	0.03349	0.03259	54.451	3.59812	6.94074	0.40653	10.95	0	0	0	0	0	0	0	0.000
400	21,000	0.03349	0.03259	85.747	5.66616	6.88331	0.40653	12.96	0	0	0	0	0	0	0	0.000
700	41,000	0.03349	0.03259	145.263	9.59898	6.61453	0.40653	16.62	0	0	0	0	0	0	0	0.000
1,000	55,000	0.03349	0.03259	205.322	13.56768	6.04081	0.40653	20.02	0	0	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM																
50	4,000	0.03349	0.03259	10.492	0.69331	4.78494	0.40653	5.88	0	0	0	0	0	0	0	0.000
70	5,800	0.03349	0.03259	15.015	0.99219	4.78476	0.40653	6.18	0	0	0	0	0	0	0	0.000
100	9,500	0.03349	0.03259	21.105	1.39458	5.10282	0.40653	6.91	0	0	0	0	0	0	0	0.000
150	16,000	0.03349	0.03259	34.910	2.30712	5.12236	0.40653	7.84	0	0	0	0	0	0	0	0.000
200	22,000	0.03349	0.03259	44.501	2.94063	5.45475	0.40653	8.80	0	0	0	0	0	0	0	0.000
250	27,500	0.03349	0.03259	56.622	3.74158	5.46559	0.40653	9.62	0	0	0	0	0	0	0	0.000
400	50,000	0.03349	0.03259	87.737	5.79766	5.85535	0.40653	12.06	0	0	0	0	0	0	0	0.000
LOW PRESSURE SODIUM																
35	4,800	0.03349	0.03259	11.397	0.75311	6.19597	0.40653	7.36	0	0	0	0	0	0	0	0.000
55	8,000	0.03349	0.03259	15.196	1.00415	6.64326	0.40653	8.05	0	0	0	0	0	0	0	0.000
90	13,500	0.03349	0.03259	23.698	1.56596	7.48551	0.40653	9.46	0	0	0	0	0	0	0	0.000
135	22,500	0.03349	0.03259	32.924	2.17562	7.92720	0.40653	10.51	0	0	0	0	0	0	0	0.000
180	33,000	0.03349	0.03259	41.426	2.73743	8.23864	0.40653	11.38	0	0	0	0	0	0	0	0.000
								TOTAL MIDNIGHT	0	0	0	0	0	0	0	0.000
								Total Lamp Inventory	486,724							
TAPD AUXILIARY POWER DEVICE:																
		0.03349	0.03259	44.000	2.90752	8.63	5.78	13.22	3,500	3,210	12,945	2,670	17,825	2,151	19,976	66,000
										3,210	12,945	2,670	17,825	2,151	19,976	66,000
								TOTAL SCHEDULE LS-1		8,466,182	29,635,527	2,377,045	40,478,774	8,267,935	48,746,709	360,816,382

APPENDIX C

TABLE 3

LS-3 A - MULTIPLE SERVICE/ALL NIGHT 1992

WATTS	LUMENS	BASE ENERGY RATE	OTHER ENERGY RATE	KWH PER MONTH	MONTHLY ENERGY CHARGE (1+2)*3	NON-ENERGY RATES FACILITIES	NON-ENERGY RATES OTHER	RATE PER LAMP (4+5+6)	FORECAST INVENTORY	BASE ENERGY REVENUES	FACILITIES REVENUES	OTHER NON-ENERGY REVENUES	TOTAL BASE REVENUES (9+10+11)	OFFSET ENERGY REVENUES	TOTAL REVENUES (12+13)	ANNUAL KWH
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
INCANDESCENT LAMPS																
103	1,000	0.03246	0.03170	35.535	2.27593	0.07733	0.79164	3.15	103	1,426	56	978	2,500	1,392	3,892	43,921
202	2,500	0.03246	0.03170	65.650	4.47131	0.07733	0.79164	5.34	199	5,402	185	1,895	7,477	5,276	12,753	158,420
327	4,000	0.03246	0.03170	112.815	7.23021	0.07733	0.79164	8.11	375	16,479	348	3,562	20,389	16,093	36,483	507,668
448	6,000	0.03246	0.03170	154.565	9.91657	0.07733	0.79164	10.79	57	3,432	53	541	4,026	3,351	7,377	105,713
695	10,000	0.03246	0.03170	238.650	15.27329	0.07733	0.79164	16.14	27	2,504	25	256	2,785	2,445	5,230	77,328
MERCURY VAPOR LAMPS																
100	4,000	0.03246	0.03170	45.195	2.89978	0.07733	0.79164	3.77	1,057	32,655	1,723	17,648	52,035	31,926	83,961	1,007,135
175	7,950	0.03246	0.03170	74.920	4.78128	0.07733	0.79164	5.65	2,040	59,215	1,893	19,379	80,487	57,829	138,316	1,824,358
250	12,000	0.03246	0.03170	103.845	6.66278	0.07733	0.79164	7.53	585	23,025	547	5,595	29,167	23,267	52,434	733,978
400	21,000	0.03246	0.03170	163.530	10.49200	0.07733	0.79164	11.36	5,212	331,995	4,837	49,512	386,344	324,222	710,566	10,227,829
700	41,000	0.03246	0.03170	277.035	17.77457	0.07733	0.79164	18.64	1,557	162,621	1,398	14,316	178,335	158,814	337,149	5,009,931
1,000	55,000	0.03246	0.03170	391.575	25.12345	0.07733	0.79164	25.99	137	20,896	127	1,304	22,328	20,407	42,731	643,749
HIGH PRESSURE SODIUM																
50	4,000	0.03246	0.03170	20.818	1.33564	0.07733	0.79164	2.21	1,334	10,164	1,238	12,388	23,762	9,926	33,688	313,816
70	5,800	0.03246	0.03170	28.633	1.83722	0.07733	0.79164	2.71	19,335	126,430	10,518	107,678	244,627	123,465	368,096	3,898,933
100	9,500	0.03246	0.03170	49.365	2.58982	0.07733	0.79164	3.46	7,928	124,852	7,357	75,313	207,322	121,733	329,055	3,840,755
150	16,000	0.03246	0.03170	66.565	4.27209	0.07733	0.79164	5.14	7,338	191,660	6,850	70,203	268,729	187,188	455,918	5,864,758
200	22,000	0.03246	0.03170	84.870	5.44526	0.07733	0.79164	6.31	15,992	528,673	14,840	151,919	695,432	516,294	1,211,726	16,286,852
250	27,500	0.03246	0.03170	107.965	6.92832	0.07733	0.79164	7.80	13,548	569,776	12,570	128,683	711,029	556,436	1,267,465	17,553,178
310	37,000	0.03246	0.03170	132.835	8.47778	0.07733	0.79164	9.35	848	43,543	785	8,037	52,365	42,533	94,898	1,341,435
400	50,000	0.03246	0.03170	167.325	10.73557	0.07733	0.79164	11.60	5,514	359,303	5,117	52,381	416,801	350,960	767,849	11,071,565
LOW PRESSURE SODIUM																
35	4,800	0.03246	0.03170	21.735	1.39452	0.07733	0.79164	2.26	428	3,632	398	4,075	8,105	3,547	11,652	111,812
55	8,000	0.03246	0.03170	28.985	1.85936	0.07733	0.79164	2.73	6,337	70,465	5,788	59,350	135,603	68,757	204,360	2,168,878
90	13,500	0.03246	0.03170	45.855	2.94171	0.07733	0.79164	3.81	117	2,060	109	1,111	3,280	2,011	5,291	63,054
135	22,500	0.03246	0.03170	62.795	4.02888	0.07733	0.79164	4.90	2,433	59,506	2,258	23,113	84,877	58,113	142,990	1,833,317
180	33,000	0.03246	0.03170	78.965	5.06656	0.07733	0.79164	5.94	883	26,558	858	8,198	35,557	25,538	61,095	818,176
									86,037	2,776,938	79,848	817,328	3,674,098	2,711,918	6,386,016	85,549,833

APPENDIX C

TABLE 3

LS-2

B - MULTIPLE SERVICE/MIDNIGHT 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL MWH (15)
INCANDESCENT LAMPS																
103	1,000	0.03349	0.03259	18.633	1.23127	0.07733	0.78164	2.10	0	0	0	0	0	0	0	0.000
202	2,500	0.03349	0.03259	36.542	2.41470	0.07733	0.78164	3.20	0	0	0	0	0	0	0	0.000
327	4,000	0.03349	0.03259	59.034	3.90090	0.07733	0.78164	4.70	0	0	0	0	0	0	0	0.000
448	6,000	0.03349	0.03259	81.043	5.35533	0.07733	0.78164	6.22	0	0	0	0	0	0	0	0.000
690	10,000	0.03349	0.03259	124.831	8.24817	0.07733	0.78164	9.12	0	0	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS																
100	4,000	0.03349	0.03259	23.690	1.56596	0.07733	0.78164	2.43	0	0	0	0	0	0	0	0.005
175	7,950	0.03349	0.03259	39.074	2.58201	0.07733	0.78164	3.45	7	110	6	66	182	107	289	3.313
250	12,000	0.03349	0.03259	54.451	3.59812	0.07733	0.78164	4.47	5	108	5	47	161	106	267	3.267
400	21,000	0.03349	0.03259	85.747	5.66616	0.07733	0.78164	6.54	17	516	18	161	763	570	1,333	17.413
700	40,000	0.03349	0.03259	145.263	9.59898	0.07733	0.78164	10.47	0	0	0	0	0	0	0	0.000
1,000	55,000	0.03349	0.03259	205.322	13.56760	0.07733	0.78164	14.48	0	0	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM																
50	4,000	0.03349	0.03259	10.492	0.69331	0.07733	0.78164	1.56	0	0	0	0	0	0	0	0.000
70	5,800	0.03349	0.03259	15.015	0.99219	0.07733	0.78164	1.86	39	235	36	370	641	229	870	7.037
100	9,500	0.03349	0.03259	21.165	1.39858	0.07733	0.78164	2.27	109	922	101	1,035	2,063	902	2,965	37.644
150	16,000	0.03349	0.03259	34.914	2.30712	0.07733	0.78164	3.18	6	84	6	52	147	82	229	3.514
200	22,000	0.03349	0.03259	44.501	2.94063	0.07733	0.78164	3.80	43	769	40	400	1,217	748	1,965	22.963
250	27,500	0.03349	0.03259	56.622	3.74158	0.07733	0.78164	4.60	4	91	4	38	133	89	222	3.278
310	37,000	0.03349	0.03259	69.205	4.57835	0.07733	0.78164	5.45	0	0	0	0	0	0	0	0.000
400	50,000	0.03349	0.03259	87.737	5.79766	0.07733	0.78164	6.67	0	0	0	0	0	0	0	0.000
LOW PRESSURE SODIUM																
35	4,000	0.03349	0.03259	11.397	0.75311	0.07733	0.78164	1.62	0	0	0	0	0	0	0	0.000
55	8,000	0.03349	0.03259	15.196	1.00415	0.07733	0.78164	1.87	24	142	22	221	397	143	540	4.376
90	13,500	0.03349	0.03259	23.698	1.56596	0.07733	0.78164	2.43	0	0	0	0	0	0	0	0.000
135	22,500	0.03349	0.03259	32.924	2.17562	0.07733	0.78164	3.04	5	65	5	47	118	64	182	1.975
180	33,000	0.03349	0.03259	41.426	2.73743	0.07733	0.78164	3.61	0	0	0	0	0	0	0	0.000
									259	3,124	246	2,437	5,822	3,040	8,862	93.298
								TOTAL LS-2 MULTIPLE	86,356	3,200,068	80,882	819,778	3,819,920	2,814,956	6,394,076	85,882,731

APPENDIX C

TABLE 3

LS-2

C - SERIES SERVICE/ALL NIGHT 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)
INCANDESCENT LAMPS								
103	1,000	0.03246	0.03170	29.520	1.89452	3.39930	0.57406	5.87
202	2,500	0.03246	0.03170	64.567	4.14262	3.39930	0.57406	8.12
327	4,000	0.03246	0.03170	97.630	6.26445	3.39930	0.57406	10.24
448	6,000	0.03246	0.03170	136.614	8.76515	3.39930	0.57406	12.74
690	10,000	0.03246	0.03170	227.559	14.60019	3.39930	0.57406	18.57
MERCURY VAPOR LAMPS								
100	4,000	0.03245	0.03170	51.675	3.31547	3.39930	0.57406	7.28
175	7,900	0.03246	0.03170	85.574	5.49043	3.39933	0.57406	9.46
250	12,000	0.03246	0.03170	117.819	7.55927	3.39930	0.57406	11.53
400	21,000	0.03246	0.03170	183.965	11.80307	3.39930	0.57406	15.78
700	41,000	0.03246	0.03170	314.144	20.15535	3.39930	0.57406	24.13
1,000	55,000	0.03246	0.03170	442.338	28.38041	3.39930	0.57406	32.35
HIGH PRESSURE SODIUM								
50	4,000	0.03246	0.03170	30.746	1.97266	3.39930	0.57406	5.95
70	5,800	0.03246	0.03170	40.834	2.61991	3.39930	0.57406	6.59
100	9,500	0.03246	0.03170	58.128	3.72945	3.39930	0.57406	7.70
150	16,000	0.03246	0.03170	83.540	5.36013	3.39930	0.57406	9.34
200	22,000	0.03246	0.03170	111.933	7.18162	3.39930	0.57406	11.15
LOW PRESSURE SODIUM								
35	4,800	0.03246	0.03170	24.235	1.55492	3.39930	0.57406	5.53
55	8,000	0.03246	0.03170	34.200	2.19427	3.39930	0.57406	6.17
90	13,500	0.03246	0.03170	61.750	3.96188	3.39930	0.57406	7.94
135	22,500	0.03246	0.03170	87.875	5.63806	3.39930	0.57406	9.61
180	33,000	0.03246	0.03170	104.025	6.67424	3.39930	0.57406	10.65

WATTS	LUMENS	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL KWH (15)
INCANDESCENT LAMPS									
103	1,000	939	18,830	38,303	6,469	55,972	10,547	66,119	333,722
202	2,500	1,045	46,432	75,261	12,710	134,373	45,316	179,689	1,429,513
327	4,000	711	37,046	29,003	4,858	60,942	26,408	87,350	833,047
448	6,000	270	14,368	11,014	1,860	27,242	14,031	41,273	442,639
690	10,000	2	620	286	48	954	606	1,560	19,115
MERCURY VAPOR LAMPS									
100	4,000	2,186	44,081	89,170	15,059	148,330	42,974	191,301	1,355,539
175	7,900	1,067	35,566	43,525	7,350	85,441	35,733	121,174	1,055,619
250	12,000	333	14,033	13,176	2,225	30,224	14,476	44,700	456,666
400	21,000	7,201	516,024	293,740	49,606	859,350	503,923	1,363,273	15,896,611
700	41,000	2,313	283,067	94,351	15,934	393,352	276,440	669,792	8,729,481
1,000	55,000	163	28,045	6,649	1,123	35,857	27,427	63,284	865,313
HIGH PRESSURE SODIUM									
50	4,000	4,195	53,833	183,358	30,965	268,156	52,573	320,729	1,658,439
70	5,800	4,154	86,072	169,448	28,616	284,136	84,525	328,661	2,035,453
100	9,500	1,541	34,891	62,860	10,616	108,367	34,074	142,441	1,074,903
150	16,000	1,060	34,918	43,239	7,342	85,055	33,705	118,760	1,063,265
200	22,000	2,612	125,656	117,561	19,853	263,070	122,714	385,784	3,871,891
LOW PRESSURE SODIUM									
35	4,800	175	1,658	7,139	1,206	9,996	1,613	11,609	59,873
55	8,000	10,941	145,758	446,301	75,369	667,428	142,339	809,768	4,493,186
90	13,500	214	5,147	8,729	1,474	15,359	5,027	20,377	158,574
135	22,500	2,837	96,766	115,318	19,474	231,558	94,500	326,058	2,985,072
180	33,000	514	20,766	20,845	3,520	45,071	20,221	65,292	637,815
		45,025	1,605,744	1,869,278	315,677	3,790,717	1,558,169	5,350,886	49,459,012

TABLE 3

LS-2 — D - SERIES SERVICE/MIDNIGHT 1992

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES FACILITIES (5)	NON-ENERGY RATES OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL MWH (15)
INCANDESCENT LAMPS																
103	1,000	0.03349	0.03259	15.618	1.02345	3.39930	0.57406	5.00	0	0	0	0	0	0	0	0.000
202	2,500	0.03349	0.03259	33.868	2.23787	3.39930	0.57406	6.21	4	54	163	28	245	53	295	1.626
327	4,000	0.03349	0.03259	53.212	3.38409	3.39930	0.57406	7.36	0	0	0	0	0	0	0	0.000
448	6,000	0.03349	0.03259	71.656	4.73503	3.39930	0.57406	8.71	0	0	0	0	0	0	0	0.000
690	10,000	0.03349	0.03259	119.357	7.88711	3.39930	0.57406	11.86	0	0	0	0	0	0	0	0.000
MERCURY VAPOR LAMPS																
100	4,000	0.03349	0.03259	27.813	1.74103	3.39930	0.57406	5.76	0	0	0	0	0	0	0	0.000
175	7,900	0.03349	0.03259	44.898	2.95686	3.39930	0.57406	6.94	0	0	0	0	0	0	0	0.000
250	12,000	0.03349	0.03259	61.817	4.08487	3.39930	0.57406	8.06	44	1,093	1,795	303	3,191	1,064	4,255	32.639
400	21,000	0.03349	0.03259	96.521	6.37811	3.39930	0.57406	10.35	0	0	0	0	0	0	0	0.000
700	41,000	0.03349	0.03259	164.844	10.89289	3.39930	0.57406	14.87	0	0	0	0	0	0	0	0.000
1,000	55,000	0.03349	0.03259	232.003	15.33008	3.39930	0.57406	19.31	0	0	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM																
50	4,000	0.03349	0.03259	16.134	1.06613	3.39930	0.57406	5.04	54	350	2,293	372	2,925	340	3,266	10.455
70	5,800	0.03349	0.03259	21.429	1.41603	3.39930	0.57406	5.39	0	0	0	0	0	0	0	0.000
100	9,500	0.03349	0.03259	30.504	2.01570	3.39930	0.57406	5.99	0	0	0	0	0	0	0	0.000
150	16,000	0.03349	0.03259	43.865	2.89860	3.39930	0.57406	6.87	87	1,534	3,549	599	5,683	1,492	7,174	45.795
200	22,000	0.03349	0.03259	58.739	3.88147	3.39930	0.57406	7.85	7	165	216	48	439	161	660	4.934
LOW PRESSURE SODIUM																
35	4,800	0.03349	0.03259	12.709	0.83981	3.39930	0.57406	4.81	0	0	0	0	0	0	0	0.000
55	8,000	0.03349	0.03259	17.942	1.18569	3.39930	0.57406	5.16	1,045	7,535	42,627	7,199	57,361	7,333	64,694	224.993
90	13,500	0.03349	0.03259	32.398	2.14073	3.39930	0.57406	6.11	6	78	245	41	364	76	440	2.333
135	22,500	0.03349	0.03259	46.102	3.04642	3.39930	0.57406	7.02	76	1,408	3,100	524	5,032	1,370	6,452	42.045
180	33,000	0.03349	0.03259	54.575	3.60632	3.39930	0.57406	7.58	0	0	0	0	0	0	0	0.000
									1,323	12,217	53,988	9,114	75,299	11,890	87,189	362.820
								TOTAL LS-2 SERIES	47,148	1,617,981	1,925,244	324,291	3,866,018	1,380,059	5,446,073	49,033,832
NON STANDARD LAMPS:																
ALL NIGHT MULT		0.03216	0.03170	74.420	4.77485	0.07733	0.25188	5.64	3,651	105,037	3,380	34,803	143,908	103,359	247,267	3,260,533
ALL NIGHT SERIES		0.03216	0.03170	113.793	7.30096	3.39930	0.57406	11.27	4,015	177,563	165,270	27,650	369,395	173,292	543,198	5,403,547
MIDNIGHT MULT		0.03349	0.03259	58.567	3.56965	0.07733	0.25188	3.44	157	2,454	146	6,491	6,091	2,380	8,479	23,263
MIDNIGHT SERIES		0.03349	0.03259	59.672	3.90385	3.39930	0.57406	7.88	0	0	0	0	0	0	0	0.000
								TOTAL LS-2 NONSTD	7,833	286,354	167,515	65,853	517,358	279,544	796,902	8,816,343
POWER FACTOR REVENUES		RATE PER KVAR =	0.35	KVAR =	374,752					-	131,163	-	131,163	-	131,163	-
VOLTAGE DISCOUNTS										(167,023)	-	-	(167,023)	-	(167,023)	-
								TOTAL LS-2	141,367	4,517,373	2,301,001	1,300,481	8,027,474	4,374,559	12,032,033	114,292,956

TABLE 3

ES-3 1992

	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	TOTAL ENERGY RATE (1+2) (3)	ANNUAL GWH (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	CUSTOMER CHARGE (5+6) (7)	AVERAGE CUSTOMERS (8)
ENERGY REVENUES								
MULTIPLE	0.03246	0.03170	0.06416	44.823	-	-	-	-
SERIES	0.03246	0.03170	0.06416	6.170	-	-	-	-
CUSTOMER CHARGE								
MULTIPLE					0.14520	9.36970	9.51	3,569
SERIES					87.55662	32.71960	120.29	85
								3,654
VOLTAGE DISCOUNT								
RELAMPING								
TOTAL ES-3								

Average Lamp Rate = 0.37 Number of Lamps = 168

	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL MWH (15)
ENERGY REVENUES							
MULTIPLE	1,434,555	-	-	1,434,555	1,420,889	2,875,444	44,823,000
SERIES	200,378	-	-	200,378	155,509	355,887	6,170,000
CUSTOMER CHARGE							
MULTIPLE	-	6,239	401,288	407,508	-	407,508	-
SERIES	-	89,310	33,374	122,692	-	122,692	-
	1,655,233	95,537	434,663	2,165,433	1,616,478	3,801,910	50,993,000
VOLTAGE DISCOUNT	(18,626)	-	-	(18,626)	-	(18,626)	-
RELAMPING	-	0	218	218	-	218	-
TOTAL ES-3	1,636,607	95,537	435,373	2,147,517	1,616,478	3,763,995	50,993,000

APPENDIX C
TABLE 3

OL-1 1992 ALL NIGHT SERVICE

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL KWH (15)
MERCURY VAPOR LAMPS																
175	7,900	0.03246	0.03170	74.520	4.78120	3.26524	0.40653	8.45	1	29	39	5	73	28	101	0.814
400	21,000	0.03246	0.03170	168.460	10.80839	4.33556	0.40653	15.55	1	66	52	5	123	44	167	2.022
HIGH PRESSURE SODIUM																
50	4,000	0.03246	0.03170	20.010	1.28384	2.50798	0.40653	4.20	5	31	155	24	210	38	256	1.201
70	5,800	0.03246	0.03170	28.635	1.83722	2.61114	0.40653	4.85	5,019	56,662	159,175	24,782	240,619	55,335	295,954	9,749,549
100	9,500	0.03246	0.03170	43.355	2.54362	2.63104	0.40653	5.63	7,603	119,455	231,951	37,076	356,922	116,697	513,219	3,810,258
150	16,000	0.03246	0.03170	66.515	4.27209	2.63143	0.40653	7.30	3	130	157	24	311	127	438	3.955
200	22,000	0.03246	0.03170	84.870	5.44535	2.97520	0.40653	8.83	6,155	204,758	221,176	30,320	456,195	203,003	656,198	6,309,336
250	27,500	0.03246	0.03170	107.965	6.92832	2.95329	0.40653	10.32	0	0	0	0	0	0	0	0.000
400	50,000	0.03246	0.03170	157.535	10.73557	3.13325	0.40653	14.28	0	0	0	0	0	0	0	0.000
LOW PRESSURE SODIUM																
35	4,800	0.03246	0.03170	21.735	1.39433	3.47579	0.40653	5.28	1	8	42	5	55	8	63	0.261
55	8,000	0.03246	0.03170	28.910	1.85934	3.47579	0.40653	5.74	8	99	334	39	463	88	551	2.717
90	13,500	0.03246	0.03170	45.195	2.89971	4.07231	0.40653	7.38	0	0	0	0	0	0	0	0.000
135	22,500	0.03246	0.03170	62.730	4.02461	4.51683	0.40653	8.95	1	24	54	5	83	24	107	0.733
180	33,000	0.03246	0.03170	78.005	5.00496	4.35411	0.40653	9.87	0	0	0	0	0	0	0	0.000
								TOTAL ALL NIGHT	18,897	366,341	623,135	92,186	1,084,663	372,812	1,457,074	11,748,022

MIDNIGHT SERVICE

WATTS	LUMENS	BASE ENERGY RATE (1)	OTHER ENERGY RATE (2)	KWH PER MONTH (3)	MONTHLY ENERGY CHARGE (1+2)*3 (4)	NON-ENERGY RATES: FACILITIES (5)	NON-ENERGY RATES: OTHER (6)	RATE PER LAMP (4+5+6) (7)	FORECAST INVENTORY (8)	BASE ENERGY REVENUES (9)	FACILITIES REVENUES (10)	OTHER NON-ENERGY REVENUES (11)	TOTAL BASE REVENUES (9+10+11) (12)	OFFSET ENERGY REVENUES (13)	TOTAL REVENUES (12+13) (14)	ANNUAL KWH (15)
MERCURY VAPOR LAMPS																
175	7,900	0.03349	0.03259	39.074	2.58201	3.26524	0.40653	6.35	0	0	0	0	0	0	0	0.000
400	21,000	0.03349	0.03259	85.747	5.66616	4.33556	0.40653	10.41	0	0	0	0	0	0	0	0.000
HIGH PRESSURE SODIUM																
50	4,000	0.03349	0.03259	10.492	0.69336	2.50798	0.40653	3.66	0	0	0	0	0	0	0	0.000
70	5,800	0.03349	0.03259	15.015	0.99219	2.61114	0.40653	4.01	0	0	0	0	0	0	0	0.000
100	9,500	0.03349	0.03259	21.165	1.39850	2.63104	0.40653	4.44	0	0	0	0	0	0	0	0.000
150	16,000	0.03349	0.03259	34.914	2.30712	2.62141	0.40653	5.34	0	0	0	0	0	0	0	0.000
200	22,000	0.03349	0.03259	44.501	2.94063	2.97520	0.40653	6.32	0	0	0	0	0	0	0	0.000
250	27,500	0.03349	0.03259	56.622	3.74158	2.90329	0.40653	7.05								
400	50,000	0.03349	0.03259	87.737	5.79766	3.13325	0.40653	9.34								
LOW PRESSURE SODIUM																
35	4,800	0.03349	0.03259	11.397	0.75311	3.47579	0.40653	4.64	0	0	0	0	0	0	0	0.000
55	8,000	0.03349	0.03259	15.196	1.00415	3.47579	0.40653	4.89	0	0	0	0	0	0	0	0.000
90	13,500	0.03349	0.03259	23.650	1.56596	4.07231	0.40653	6.04	0	0	0	0	0	0	0	0.000
135	22,500	0.03349	0.03259	32.924	2.17562	4.51683	0.40653	7.10	0	0	0	0	0	0	0	0.000
180	33,000	0.03349	0.03259	41.426	2.73743	4.39411	0.40653	7.54	0	0	0	0	0	0	0	0.000
								TOTAL MIDNIGHT	0	0	0	0	0	0	0	0.000
OL-1 POLE CHARGE: Monthly Per Pole Rate= 2.72 Number of Poles = 6,512										-	212,496	-	212,496	-	212,496	-
								TOTAL OL-1	18,897	366,341	835,631	92,186	1,297,158	372,812	1,669,570	11,748,022

DWL 1992

	BASE ENERGY RATE	OTHER ENERGY RATE	KWH PER MONTH	MONTHLY ENERGY CHARGE (1+2)*3	NON-ENERGY RATES FACILITIES	OTHER	RATE PER LAMP (4+5+6)	FORECAST INVENTORY	BASE ENERGY REVENUES	FACILITIES REVENUES	OTHER NON-ENERGY REVENUES	TOTAL BASE REVENUES (9+10+11)	OFFSET ENERGY REVENUES	TOTAL REVENUES (12+13)	ANNUAL KWH
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
RATE A	0.03246	0.03174	32.341	2.07506	5.07339	0.40653	7.55	5,992	75,464	364,725	29,231	469,440	73,717	543,157	2,325,447
RATE B	0.03246	0.03170	32.340	2.07506	1.60464	0.40653	4.19	309	4,900	7,403	1,090	14,461	4,746	19,457	150,960
RATE C	-	-	-	-	0.05356	0.43333	0.49	.335	0	250	2,023	2,273	0	2,273	0.000
TOTAL DWL									80,364	372,050	33,152	486,394	78,503	564,897	2,476,415

	BASE ENERGY REVENUES	FACILITIES REVENUES	OTHER NON-ENERGY REVENUES	TOTAL BASE REVENUES	OFFSET ENERGY REVENUES	TOTAL REVENUES	ANNUAL KWH
STREETLIGHT TOTAL	15,001,766	33,239,354	4,146,197	52,417,317	14,969,067	67,379,384	476,326,635

(END OF APPENDIX C)