COM/NDS

Mailed

DEC 2 0 1991

Decision 91-12-061 December 18, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company for authority to adjust its electric rates effective November 1, 1991; and adjust its gas rate effective January 1, 1992; and for Commission order finding that PG&E's gas and electric operations during the reasonableness review period from January 1, 1990 to December 31, 1990 were prudent. (U 39 M)	Application 91-04-003 (Filed April 1, 1991)

(Appearances are listed in Appendix D.)

INDEX

O P I N I O N

I. SUMMARY OF DECISION

By this decision, we adopt the revenue allocation criteria to be used in establishing revised electric rates which become effective January 1, 1992 for Pacific Gas and Electric Company (PG&E). Our adopted revenue allocation principles are then applied in setting rates which implement all PG&E electric department revenue requirement changes to be effective January 1, 1992. Our decision addresses all revenue allocation issues related to PG&E's April 1, 1991 Energy Cost Adjustment Clause (ECAC) Application (A.) 91-04-003.

The consolidation of all rate adjustments for a January 1 effective date implements our decision in an earlier phase of this proceeding granting PG&E's proposal that the revenue changes adopted in this proceeding be deferred from the standard ECAC revision date of November 1, and consolidated with other pending rate changes effective January 1, 1992.

Since the January 1 revenue changes were unknown at the time of its filing, PG&E assumed an adopted $200 million increase in electric revenues in presenting its revenue allocation calculations to illustrate the approximate impacts of its proposals. The $200 million equals a 2.73% system average increase, and is near the midpoint of the range of revenue which PG&E expects will be adopted, based upon a low estimate of $137.3 million and a high estimate of $257.6 million. No party contested the use of $200 million for illustrative purposes, and we will refer to the $200 million for consistency in discussing the impacts of our adopted revenue allocation criteria in this decision.

The revenue adjustments to become effective on January 1, 1992 include the amounts we have adopted by previous decisions in this application relative to the ECAC, Annual Energy Rate (AER), Electric Revenue Adjustment Mechanism (ERAM), Low Income Rate Adjustment (LIRA), and Customer Energy Efficiency (CEE) programs. Other revenue adjustments which we incorporate into our adopted total revenue allocations in this decision include: PG&E's Cost of Capital proceeding (A.90-05-016), its Attrition Advice Letter, and costs for post-retirement benefits other than pensions. The total revenue requirement changes resulting from our adopted decisions for each of these proceedings yield a total net electric system increase of $158,437,000, representing a 2.2% increase, as summarized in Appendix A, Table 6.

Based on our adopted 2.2% system average increase in authorized electric revenues, our adopted revenue allocation criteria increase PG&E's customer rates by the amounts set forth in Appendix A, Table 2. A summary of these increases by major customer class is as follows:

Customer Class	Percentage Change
Residential	1.53%
Agricultural	2.24
Streetlighting	(2.13)
Small Light & Power	6.48
Medium Light & Power	2.10
E-19 Tariff	(2.90)
E-20 Tariff	2.55
E-20 Contracts	(2.24)
E-20 Total	2.23
Total System	2.16%

Our adopted revenue allocation conforms to Assembly Bill (AB) 2236 which was enacted subsequent to the close of hearings in this proceeding. Given the restrictions of AB 2236, we adopt the maximum revenue allocation allowed to agricultural customers under the bill, limited to the system average percentage change (SAPC), or 2.2% of total electric revenue.

In the absence of AB 2236, we would reach a different conclusion based upon the evidentiary record in this proceeding. We would adopt a cap for agricultural rates equal to the SAPC plus 5%. Accordingly, we present our conclusions based on the evidentiary record first. Then, we separately apply the provisions of AB 2236 to determine our final adopted basis for revenue allocation.

II. PROCEDURAL BACKGROUND

PG&E filed A.91-04-003 on April 1, 1991 to adjust rates for its ECAC and related tariff clauses in accordance with the Rate Case Plan (RCP) adopted in Decision (D.) 89-01-040. The RCP provides that revenue allocation issues be considered in ECAC proceedings while rate design issues are reserved for General Rate Cases (GRCs) and annual Rate Design Window (RDW) proceedings.

PG&E updated its original testimony on September 3, 1991 to incorporate significant revisions which had occurred since its April 1 filing. The updated testimony assumed revenues at present rates in effect on May 1, 1991, as adopted in D.91-04-062, PG&E's 1991 RDW proceeding.

By decisions issued earlier in this proceeding, we have already adopted revenue adjustments for PG&E's ECAC, AER, ERAM, LIRA, and CEE.

Evidentiary hearings on revenue allocation issues were held on September 18-20, 1991, in San Francisco. The active parties who sponsored testimony in this phase of the proceeding were PG&E, the Agricultural Energy Consumers Association (AECA), the California Farm Bureau (CFB), California Large Energy Consumers Association (CLECA), and the Federal Executive Agencies (FEA). The following additional parties did not sponsor witnesses, but filed briefs: the Commission's Division of Ratepayer Advocates (DRA), Toward Utility Rate Normalization (TURN), the California City-County Street Lighting Association (CAL-SLA), and the California Manufacturers' Association (CMA).

III. INTERCLASS REVENUE ALLOCATION FRAMEWORK

In recent years, we have repeatedly stated our goal to move toward an allocation of revenues among customer classes based upon an equal percentage of marginal cost (EPMC) approach.

The EPMC approach first calculates the revenues that would result if each customer class paid prices equal to marginal costs for the services the class requires. Because the resulting marginal cost revenues rarely equal the utility's revenue requirement, the marginal cost revenue requirement must be adjusted to equal the total utility revenue requirement. The same percentage change is applied to the marginal cost revenues for each individual customer class in order to derive the EPMC revenue allocation for that class.

Marginal costs used for revenue allocation measure the change in total costs resulting from an incremental change in a specified element of the utility's operation. Three general types of marginal costs apply to electric utilities. Marginal capacity costs measure the unit costs due to peak kilowatt demand changes. Marginal customer costs relate to customer hook-up and account servicing costs due to changes in number of customers served. Marginal energy costs vary with changes in kilowatt-hours (kWh) of energy provided.

We adopt marginal capacity and marginal customer costs in general rate proceedings, and rely upon those adopted marginal costs for computing revenue allocations during ECAC proceedings. Marginal energy costs are updated in each ECAC proceeding to incorporate the adopted resource assumptions. In this proceeding, PG&E has used the marginal capacity and customer costs adopted in its 1990 GRC in revenue allocations. PG&E updated its marginal energy costs to reflect the resource assumptions adopted in the Administrative Law Judge (ALJ) ruling dated August 15, 1991 in this proceeding. These same assumptions were incorporated into the proposed ALJ decision on ECAC forecast issues filed October 18, 1991.

Historically, agricultural class rates have remained significantly below full EPMC-based rates. In past revenue allocation proceedings, we have used interclass caps on allowable rate changes to mitigate potential billing impacts on agricultural customers which would result if we increased rates based on full EPMC. We have previously used the SAPC plus a fixed percentage as a cap to establish interclass revenue allocations. In last year's ECAC proceeding, we advised parties that in future revenue allocations, we expect anyone who urges us to depart from our guideline cap of SAPC plus 5% to present specific evidence demonstrating that such departures are warranted or required by the nature of the demand of agricultural customers for electric service.

Consistent with its 1990 GRC and 1990 ECAC decisions, PG&E used the average Utility Electric Generation (UEG) gas price, excluding customer costs, and used the Zero Intercept Method (ZIM) time-of-use ratios in determining its revenue allocations. PG&E assumed an energy reliability index (ERI) of 0.56, based on the average 1992-1997 ERIs adopted in PG&E's 1990 GRC.

IV. UNCONTESTED ISSUES

PG&E presented various proposals in this proceeding which either were never disputed or were ultimately agreed to by parties after modification. We conclude that PG&E's uncontested proposals are reasonable and we will adopt them, as presented below.

A. Rate Floor

PG&E proposes a rate floor of SAPC minus 5%, although in the 1990 ECAC proceeding, we adopted a floor of no decrease from then-present revenues. PG&E explains that in the context of the smaller increase in system revenues expected in this year's proceeding, a floor of no decrease may not produce nonagricultural class allocations which are the same percentage of full EPMC. However, the same percentage above full EPMC can be achieved by using a floor of SAPC minus 5%.

CLECA agrees that a rate floor of no decrease creates substantial distortions in EPMC relationships among classes, but believes the best solution is the lack of any floor. Yet, based on the size of the increase in the proceeding, both CLECA's and PG&E's floor proposals have the same result (Ex. 123). No other party disputed this recommendation.

We adopt PG&E's floor of SAPC minus 5% since it eliminates the distortions resulting from a zero-decrease floor, and since it has the same outcome as CLECA's proposal.

B. Intraclass Revenue Allocation

PG&E proposes that intraclass allocations to rate schedules use a guideline cap similar to that adopted for interclass allocations. For the agricultural class, PG&E proposes assigning the agricultural class average percentage change to all schedules. We find this proposal to be reasonable, and adopt it.

C. Rate Design

Although rate design issues are more appropriately considered in GRC and related RDW proceedings, limited issues can arise in the application and interpretation of established rate design criteria which may properly be dealt with in revenue allocation proceedings. In this proceeding, PG&E proposes the following guidelines for rate design for rates to be effective January 1, 1992:

- Residential: Maintain the composite tier differential of \$0.02732 per kWh which was adopted in the 1990 RDW. The composite tier differential is defined as the tier 2 rate minus the composite tier 1 rate, including minimum bill revenue. Maintaining the cents per kWh differential, rather than the percentage differential, is consistent with PG&E's 1990 ECAC decision.

- Agricultural: Connected load and maximum and on-peak demand charges on each schedule are increased by the percentage increase to the revenue allocation of that schedule. The demand charge limiter is increased by the average percentage increase to the AG-1B, AG-RB, AG-VB, AG-4B, and AG-4C schedules.

- Time-of-Use (TOU) Energy Charges: These charges are set to preserve the relative relationships in current rates.

- Commercial/Industrial Charges: FEA and CLECA initially disagreed with PG&E's allocations which resulted in greater percentage increases for energy charges than for demand charges for industrial rate schedules. PG&E subsequently changed its proposed allocations between energy and demand charges, resulting in a consensus among all parties on this issue. PG&E's revised allocations reflect the following principles as described by PG&E witness Mr. Smith (Tr. 1285):

    - Increase maximum and peak demand charges and rate limiters by the average percentage increase to the Medium Light & Power (L&P), E-19, and E-20 classes.

    - Hold constant the transmission maximum demand charge since an increase would move rates away from full EPMC.

    - Have consistency among the maximum and peak demand charges on Schedules A-10, A-11, E-19, and E-20.

    - Increase demand and energy changes by the same percentage, or, if this is impossible, to increase the demand charges by a larger percentage than the energy charges.

Rates reflecting these principles are contained in Exhibit 122 as agreed to by PG&E, FEA, CLECA, and DRA. (Tr. 1531, 1550, 1592.) No party opposed this recommendation. The consensus reached by the parties reflects a reasonable resolution, and we adopt it.

D. Combining of Rate Schedules A-11 and E-19

Rate Schedules A-11 and E-19 are TOU schedules serving medium-sized commercial and industrial customers. PG&E proposes to eliminate Schedule A-11 and to offer all existing A-11 customers the option of taking service under Schedule E-19. Schedule E-19 firm service would also be made available to any A-10 customer who requests TOU service.

In the 1990 RDW proceeding, PG&E noted a problem with customer migration to Schedule A-11 because of its attractive rates. Schedule E-19 serves all customers with demands between 500 and 1000 kW, while A-11 serves a group of lower-cost customers within the Medium L&P class. If the customer's demand is 500 kW or more for three consecutive months, the account is transferred to Schedule E-19 or E-20.

PG&E was concerned in the 1990 RDW proceeding that some customers might split their loads to qualify for the lower A-11 rates, based upon misleading or transitory price signals. In D.91-04-062, we noted that the instability between Schedules A-11 and E-19 rates warranted further consideration in the next available proceeding.

In this proceeding, PG&E proposes to solve this problem by following DRA's proposal in PG&E's 1990 RDW to combine Rate Schedules A-11 and E-19 (Exh. 111). PG&E proposes to make the change effective on May 1 rather than January 1, 1992. PG&E asserts that the additional four months are needed to implement the schedule conversion. The May 1 effective date coincides with the effective date of rate changes in PG&E's next RDW proceeding. Accordingly, PG&E has proposed Schedule A-11 rates for the interim period from January 1 to April 30, 1992 (Exh. 114). PG&E's proposed basis for calculating combined A-11/E-19 rates thereafter is presented in Exhibit 111 (p. 9-13). These rates were updated consistent with parties' agreement on industrial rate design described above (Exh. 122).

No party opposed this recommendation. We conclude that PG&E's proposal provides a satisfactory resolution of the problem, and we adopt it.

The rate tables in Appendices A and B to this decision show separate revenue allocations for Schedules A-11 and E-19. The revenue allocations resulting after the combination of the rate schedules on May 1, 1992 will necessarily differ from the amounts shown in the tables since they will then depend on billing determinants of the combined rates.

V. CONTESTED ISSUES

A. Parties' Positions on Interclass Revenue Allocation

All contested issues raised by parties relate to the appropriate criteria for allocation of the January 1, 1992 electric revenue increase among customer classes.

Parties agreed that all customer classes should be allocated at least some share of the revenue increase expected to be granted on January 1, 1992. Parties also agreed that some form of cap on revenue allocation is appropriate to mitigate the impacts which would otherwise result from full EPMC-based revenue allocation. Differences focused on the appropriate percentage increase over SAPC which should be assigned as a cap in determining interclass revenue allocation. As in past proceedings, the controversy over the proper cap level is driven by the effects on the agricultural class.

PG&E prepared a comparison exhibit (Exh. 116) which summarized the customer class percentage increases due to the differences in parties' positions over rate caps for agricultural customers. This exhibit is presented as Appendix C to this decision for reference. Parties' proposals for agricultural customers' cap ranged from SAPC as sponsored by AECA and CFB to 10% above SAPC as sponsored by FEA. Within this range, PG&E proposed a 5% cap, with DRA's concurrence, and CLECA proposed a 7% cap, with support from CMA. For all the proposals, classes other than agriculture are allocated revenue responsibility on the basis of EPMC.

1. <u>Proposal of PG&E</u>

PG&E proposes a cap on all class allocations of SAPC plus 5%. PG&E's proposal has the following effects:

- The agricultural class percentage increase is set at the 5% ceiling but all other classes are below the ceiling.
- The streetlighting class receives its full EPMC allocation.
- The calculation of SAPC excludes revenues from special electric contracts.
- Other customer classes receive full EPMC allocations of the remaining revenue. This results in allocations which are 1.95% above full EPMC, in order to recover the shortfall from the agricultural class.

PG&E's proposal conforms to the guidelines for future interclass revenue allocations which we adopted for future use in the 1990 ECAC proceeding. DRA supports PG&E's proposal, stating that it represents a moderate movement of agricultural rates toward reducing the subsidy now enjoyed by PG&E's agricultural customers. CAL-SLA also endorses PG&E's proposal as it related to streetlighting customers.

AECA and CFB oppose PG&E's proposal on the basis that it does not adequately consider: 1) agricultural customers' special circumstances warranting a lower cap or 2) the uncertainty over whether agricultural customers are really below EPMC by a significant amount.

FEA and CLECA believe PG&E's proposal does not go far enough in moving agriculture closer to full EPMC. FEA and CLECA argue that the relatively small total system revenue increase expected to be adopted in this proceeding provides an opportunity to make greater progress toward full EPMC rates than PG&E proposes.

2. Proposal of FEA

FEA proposes that the agricultural class receive annual increases of 10% above SAPC until that class is at full EPMC. FEA asserts that this proposal is consistent with our goal begun in 1986 to move all customer classes to full EPMC-based rates. Although FEA believes we have been successful in bringing other classes to full EPMC, it argues that agricultural rates are still 28% below full EPMC at present rate levels. Unlike other parties' proposals, only FEA's proposal would encompass multiple years, and is estimated to bring agricultural rates up to EPMC levels within four years.

FEA's proposal corresponds to a plan adopted in D.89-12-057 to bring nonfirm customers up to their estimated cost of service. That plan required annual increases of 10% above the large light and power class percentage change until these customers were at cost of service. FEA argues that equity dictates that the same plan is appropriate for the agricultural class to eliminate continuing subsidies by other customer classes.

PG&E believes that FEA merely revives an argument which we rejected in D.90-12-066 that rapid movement towards EPMC justifies higher caps (Exh. 120, pp. 4-7). PG&E argues that the phase-in plan cited by FEA is clearly distinguishable from the interclass allocation dispute in this proceeding. The phase-in plan applied only to a small fraction of the customer class, and the cap calculation applied only in certain months and for certain customers. Also, the plan raised little or no controversy, and there is no discussion in the decision resolving the conflicting proposals on the issue.

AECA challenges FEA's proposal since no analysis was made to determine whether the justifications for applying the policy to nonfirm customers in 1989 apply to agricultural customers during 1991. For example, FEA did not consider different usage patterns between the classes or economic conditions facing agriculture due to the drought and the December 1990 freeze.

3. Proposal of CLECA

CLECA proposes a revenue allocation to the agricultural class based upon a cap of 7% increase over SAPC. CLECA expresses concern that the allocation to the agricultural class is so far below full EPMC that full EPMC allocation must continue to be phased in at "such a slow pace." In light of the relatively small SAPC proposed in this proceeding, CLECA believes that we have a unique opportunity to make significant progress toward our goal of full EPMC allocation. This relatively small increase will soften the effect of any increase in the percentage allocation to the agricultural class. CLECA's proposal would result in an increase to the agricultural class of 9.75%, as compared with the 13.94% class increase granted in the 1990 ECAC proceeding.

CMA supports CLECA's proposal on the basis that it recognizes the need to eliminate continued rate subsidies for agriculture while keeping the rate impact on agriculture below the increase adopted last year.

4. Proposal of AECA and CFB

AECA and CFB both advocate allocating revenue increases to the agricultural class based upon a cap equal to SAPC. As previously mentioned, AB 2236 was enacted into law subsequent to the close of hearings in this proceeding. AB 2236 prohibits us from increasing or approving increases in agricultural rates prior to June 1, 1992, by more than the system average rate increase. Accordingly, we will first discuss our conclusions as to the proposals of AECA and CFB based upon the evidentiary record, apart from AB 2236. Then we will separately address the impacts of AB 2236 on our final conclusions.

AECA cites three major reasons supporting its proposal that agricultural customers' revenue increases be capped at SAPC.

- o There is uncertainty as to whether the agricultural class' current rate levels are significantly below EPMC.
- o State conjunctive use water policies would conflict with a policy that increased agricultural utility rates to the point that groundwater pumping would be discouraged.
- o Undue economic hardship and rate shock would result from an increase in excess of SAPC for agriculture.

CFB agrees that the reasons cited by AECA warrant a cap for agricultural customers of SAPC. CFB also sponsored testimony focusing on the economic hardships within agriculture as a basis for limiting any rate increases assigned to that customer class to SAPC. We review below parties' positions on each of these three issues:

a. <u>Agricultural Rates' Proximity to EPMC</u>

AECA believes that the basic premise for imposing rate increases greater than PG&E's SAPC upon the agricultural class is that this class is significantly below its EPMC target. AECA challenges the validity of that belief.

PG&E computed agricultural customers would require a 42.3% rate increase to reach EPMC, based upon the proposed revenue increase in this case and the adopted marginal costs. All other parties agreed with PG&E's marginal cost calculations, except for AECA and CFB.

AECA claims that "a dark cloud of uncertainty" has been cast over the premise that a significant gap exists between agricultural rates and EPMC targets. Because of this uncertainty, AECA argues that the need for further increases over and above SAPC for the agricultural class "is in serious doubt."

AECA's witness, Dr. Pflaum, testified that he has "serious concerns" about the validity of the current EPMC targets for agricultural customers. He based his concerns upon a review of the 1990 Agricultural Rates Cost Study (Tr. 1395). Although Dr. Pflaum also cited PG&E's Area Cost Study (ACS) as further basis for his conclusions, the ALJ ruled that references to the ACS in the testimony of Dr. Pflaum and in the testimony of Mr. Smith of PG&E (Exh. 111) be stricken from the record. Because of the controversy raised by this ruling, we discuss the basis for excluding references to the Area Cost Study from our evidentiary consideration separately below in Section 4b.

The Agricultural Rates Cost Study upon which Dr. Pflaum based his conclusions was completed jointly by PG&E and the Commission Advisory and Compliance Division (CACD) in November 1990 in response to D.89-12-057, which directed the preparation of a joint study of the agricultural class' marginal costs and intraclass allocations and their implications for rate design. (Ordering Paragraph 52.)

The Study considered several hypothetical revenue allocation scenarios to determine if any plausible changes in input assumptions would yield results placing the agricultural class substantially closer to the EPMC targets, given current methods. The Study did not assess the likelihood that any of the sensitivity assumptions would occur. The base case for these studies was PG&E's 1990 ECAC filing which utilized ratemaking methods from the 1990 GRC, billing data through November of 1989, and load research data through 1988.

The Agricultural Rates Cost Study concluded that even considering the potential variation in agriculture's EPMC target resulting from the sensitivity assumptions tested, the agricultural class remains a considerable distance from EPMC (Exh. 117,

p. IV-3). Agriculture was still 20% below the EPMC target in the most extreme case studied.

Dr. Pflaum reaches a different conclusion based upon his review of the same study. Dr. Pflaum concludes the agricultural class may actually be only 4.6% below its EPMC target. Dr. Pflaum's conclusion is based upon the analysis summarized in Table CPP-1 in his testimony. Dr. Pflaum combines five of the sensitivity assumptions presented in the Study and assumes they are all simultaneously applied in computing EPMC for the agricultural class. By contrast, the Study itself tested each assumption independently in reaching its conclusions as to EPMC variances relative to agriculture.

Dr. Pflaum's five sensitivity scenarios are summarized as follows:

The first sensitivity is to increase the ERI to 1.0, which moves agricultural rates to 40.5% below EPMC. TURN argues that based upon the ALJ ruling on resource assumptions in this proceeding, an ERI of 0.56 has been calculated already, precluding the chance that the ERI will be set at one. Also, since our adopted revenue allocation methodology incorporates a six-year average of ERIs, even if an ERI value of 1.0 were estimated for one year, it would only have a fractional effect on changing the ERI used for EPMC purposes. (D.89-12-057, p. 201.)

The second adjustment assumes the use of the replacement cost-new approach for calculating marginal cost. This adjustment would further lower the EPMC target to 30.1%. TURN points out, however, that our adopted policy is to use the cost of new equipment for marginal cost purposes. Thus, to accept AECA's sensitivity assumption as plausible, we would have to question the validity of our own adopted policy.

The third adjustment adds in a load diversity factor of 2.0 which would further lower the EPMC target to 18.1%. Dr. Pflaum presented no factual basis to confirm the validity of this adjustment. The Study itself admits that no factual basis has been developed to confirm that 2.0 is an appropriate level of diversity (Exh. 117, p. IV-7).

The fourth adjustment assumes a doubling of unit marginal energy cost, which would further lower the EPMC target to 10%. TURN counters that marginal energy costs have in fact decreased since last year.

The fifth and final adjustment adds a scenario of actual demand falling below the forecast. This lowers the EPMC target to 4.6%. TURN responds that the forecasted agricultural demand in this case was uncontested and will not change.

AECA does not ask the Commission to modify its adopted marginal cost methodology to incorporate any of the assumptions used in the Agricultural Rates Cost Study. Yet AECA's witness concludes that the assumptions were "within the realm of reason" (Tr. 1444-45). AECA's purpose was to demonstrate how volatile the EPMC target for agriculture is to a set of different assumptions developed by the sponsors of the study, and to illustrate that agricultural rates may be much closer to EPMC targets than is projected by parties in this proceeding.

TURN contends that Dr. Pflaum's conclusions were based on selective analysis, and that he simply ignored the portions of the report with which he disagreed. The Agricultural Rates Cost Study introduces different sensitivity analyses to test whether by changing certain assumptions related to marginal cost, the agricultural class' EPMC share can be dramatically altered. The study does not assess the probability, however, that any of these sensitivity assumptions reflect reality (Tr. 1460), nor represent them as predictions of how marginal costs will change in 1992. In fact, some of the sensitivities are contrary to the Commission's currently adopted methodology, according to TURN (Tr. 1423). TURN also believes AECA's arguments are irrelevant to this proceeding since marginal costs, except for energy, are litigated in a GRC, not an ECAC, proceeding.

DRA finds AECA's conclusions based on the Agricultural Rates Cost Study to be substantively as well as procedurally wrong. If parties dissatisfied with the marginal costs adopted in GRC decisions can successfully block rates based on those costs because of "uncertainty," then DRA believes the regulatory process itself will become arbitrary and wasteful. DRA further notes the lack of any evidence presented by AECA as to the marginal costs of serving agricultural customers, or as to the appropriateness of making any of the adjustments assumed in arriving at its conclusions as to EPMC targets.

Similar criticisms of AECA's use of the Agricultural Rates Cost Study were presented by FEA and CLECA.

b. Area Cost Study

There was controversy over the admissibility of AECA's references to PG&E's Area Cost Study (ACS) which was prepared in connection with its 1993 GRC proceeding. The assigned ALJ in this proceeding granted the motion of TURN to strike references to the ACS in the testimony of AECA. TURN's motion was supported by PG&E, DRA, CLECA, and CMA, and opposed by AECA and CFB. PG&E also offered to withdraw excerpts of the testimony of its witness referencing the ACS. (Tr. 1292.) The ALJ accepted PG&E's offer.

In briefs, AECA and CFB continued to argue for the admissibility of the AECA testimony references to the ACS. CFB cited testimony references to the ACS made by CFB witness Tibbets which had not been stricken, and argued that the ACS presented serious challenges to the reliability of existing EPMC target assumptions for the agricultural class. Yet witness Tibbets admitted he had not personally reviewed or validated any of the findings in the ACS.

CFB further cited Evidence Code Section 801 which states that testimony of an expert witness may be admitted based upon matter perceived by or personally known to the witness whether the underlying matter is admissible or not. (Tr. 1442, 43.) Aside from the fact that that under Public Utilities (PU) Code Section 1701, technical rules of evidence need not apply in our proceedings, there is no sound practical basis to admit the evidence in question.

The ACS as cited by AECA in its testimony is beyond the scope of an ECAC proceeding. It has been prepared by PG&E in connection with its Test Year 1993 GRC. We see no evidentiary basis for reliance on an expert opinion to the extent it is based on a matter which cannot be effectively used to test the credibility of the expert. No party moved to admit the actual ACS into the record in this case. Without the document in the record, we cannot reasonably test the validity of the conclusions drawn by AECA relative to the study.

In arguing for the admission into evidence of Dr. Pflaum's references to the ACS, AECA alleged that its intent in referring to the study was not to assert the truth of the matters stated in the study, but simply "to show that there's something else out there that came to a different conclusion" as to how far agricultural rates deviate from EPMC (Tr. 1244-5). AECA's counsel argued that the "different conclusion," whether right or wrong, warrants that the Commission "move cautiously" in directing agricultural rates toward EPMC. Yet the AECA testimony itself reveals that AECA seeks to ascribe a much higher degree of credibility to the ACS. AECA states:

> "PG&E's most recent analysis, the <u>Area Cost Study</u>, indicates that agriculture is only 8.7% below its EPMC target. It has become quite clear that the use of system-wide, rather than class-specific, marginal costs has resulted in greatly over-stated EPMC targets for the agricultural sector." (Exh. 119, pp. 4-5.) (Emphasis added.)

We affirm the ALJ ruling striking references to PG&E's ACS. It would not serve the record for such conclusionary statements to be admitted with no reasonable opportunity for opposing parties to probe the veracity of the underlying matters giving rise to such conclusions. In order for references to the ACS to influence our decision as to the need for caution, we would require a record showing what the ACS findings are and in what context AECA interpreted those findings. We would need to determine what weight, if any, to ascribe to the plausibility of the findings of the ACS. Absent this information, the study cannot be used to support the witness' conclusion that "a dark cloud of uncertainty" hangs over our present beliefs as to EPMC.

It would be unfair to allow one party to use such a study to make attacks on other parties' methodologies without allowing those parties an opportunity to challenge such attacks. Yet to allow such an opportunity would expand the scope of this proceeding beyond the proper limits allowed under our adopted RCP for ECAC proceedings. The issues raised in the study will be addressed within the scope of PG&E's 1993 GRC proceeding. It is speculative and premature to color our decisions based upon the mere fact that "there is something else out there" in a separate proceeding that may or may not ultimately impact future measurements of EPMC for the agricultural class, of which we have no way of testing the validity.

c. <u>Conjunctive Use Policies</u>

As used by AECA, the term "conjunctive use" water policy refers to the joint management of surface and groundwater whereby agriculture must rely more heavily on groundwater when surface water is being diverted to metropolitan areas. Increased agricultural use of groundwater through five years of drought has in turn necessitated greater electricity use to pump and transport needed water from wells to fields. Even with normal rainfall levels next year, federal Central Valley Project officials have stated that agriculture will receive only 50% of normal allocations, as depleted state reservoirs are replenished. AECA argues that "significant" increases in electric rates for agriculture at this time, which raise the cost of groundwater pumping and discourage such pumping by agriculture, are inconsistent with the state's water policies designed to protect the entire state economy from drought-induced economic hardship.

TURN disagrees, arguing that continued agricultural rate subsidies will encourage increased groundwater pumping which is economically inefficient because it does not reflect the full cost of electricity. TURN cites an excerpt from the Water Conservation Projects Act of 1985 which warns that the lowering of the water table in the San Joaquin Valley is causing irrigation water to be pumped at excessive depths, requiring even greater energy usage. TURN believes that state conjunctive use policies will in fact be aided by our setting correct price signals since farmers would use an accurate cost in evaluating to what extent to deplete groundwater supplies. Overpumping would be discouraged, reducing the risk of land subsidence which can destroy aquifers.

d. Economic Hardship

AECA argues that the agricultural class would suffer significant economic harm from a rate increase in excess of SAPC. AECA submits that agriculture has already suffered notable economic harm from five years of continued drought. Agricultural customers' costs have risen due to increased electrical usage for groundwater pumping, and that this increased usage must be considered in measuring the economic impact of further rate increases. Agricultural groundwater pumping is estimated to increase 33% in the San Joaquin Valley in 1991. AECA witness Ms. Archibald argued that a 7% electric rate increase could easily translate into 50% higher electricity expenditures by agricultural customers between 1990 and 1992. CFB presented further evidence on the economic hardship on agriculture resulting from the extended drought. According to the state's Office of Emergency Services, projected damage to agriculture for 1991 exceeds $540 million, with hardest hit areas being within PG&E's service territory. A survey conducted among CFB's own membership revealed an estimated 23% reduction in total agricultural output, resulting in a 14% decrease in their revenues for 1991. AECA and CFB also cited the December 1990 freeze as contributing to agriculture's economic hardship.

AECA argues that we have considered economic hardship to the agricultural class in past rate proceedings, citing PG&E's 1990 GRC decision where we noted our reluctance to impose "harsh rate impacts" which would "punish agricultural customers for more efficient behavior." CFB also cited our past position as stated in D.89-12-057 that although we would use a guideline of SAPC plus-or-minus 5% as a revenue allocation guideline, parties should not overrely on this formula. We reserved the right to fit the revenue allocation to the particular circumstances that we face at a given time. CFB argues that present circumstances require that the agricultural class receive no more than a SAPC revenue allocation.

TURN argues that AECA's economic hardship arguments are no basis to continue subsidizing agricultural customers at the expense of other customer classes. While California farmers receive various subsidies through legislative actions, the legislature has determined just the opposite with respect to public utility law mandating nondiscrimination in rates among classes of service (PU Code § 453.1). In addition, the effects of economic hardship are not uniform among farmers (Tr. 1575-76).

Nonagricultural customers within other customer classes have also suffered to varying degrees due to the drought and the freeze, as noted by TURN, FEA, and CLECA. Given these differential impacts, TURN believes to target aid, such as disaster relief, to those farmers who can demonstrate that they have been particularly hard hit would be more appropriate.

FEA argues that in the past, we have not dealt with financial hardship on a <u>class</u> basis, but rather through special contracts. FEA believes those agricultural customers facing the most severe economic hardships should approach PG&E, and eventually the Commission, to elicit rate concessions on an individual basis. FEA contends that this is the same route industrial customers must use to receive lower power costs, and that agricultural customers should be treated similarly.

FEA also takes exception to AECA's argument that the potential for bypass warrants lower than cost-based rates for agricultural customers (Exh. 119, p.20; Tr. 1399). FEA points out that the potential for bypass is dealt with through special contracts, and that granting a subsidy to the entire agricultural class is not appropriate merely because some may be able to bypass the system.

DRA and CLECA challenge AECA's definition of "rate shock" to include usage changes as well as per-kWh rate changes. CLECA submits that we did not evaluate "rate shock" based upon total energy bills in either the 1990 ECAC proceeding, or in any other case to CLECA's knowledge. CLECA believes it would be speculative to analyze every possible increase in usage to assess the impact of a given rate increase.

VI. ADOPTED REVENUE ALLOCATION CRITERIA

A. Overview

As previously discussed, the recent enactment of AB 2236 places certain restrictions on the amount of increase we may assign to the agricultural class. Accordingly, for purposes of discussion, we will first address the revenue allocation which we would adopt based upon the evidence presented in this proceeding. Then, we discuss the impact of AB 2236 upon our adopted revenue allocation is impacted by enactment of AB 2236.

Apart from the statutory requirements of AB 2236, we would conclude that PG&E's proposal of a cap of SAPC plus 5% would provide the most reasonable revenue allocation, given the various proposals before us in this proceeding. PG&E's marginal cost computations show that it would require a 42.26% increase to the agricultural class to bring it up to full EPMC. PG&E's EPMC cap would limit agriculture's increase to only 7.77% based on PG&E's illustrative $200 million increase. This is less than the class increase we allowed in our 1990 revenue allocation decision. We consider this amount small enough to avoid an unreasonable increase to the agricultural class yet large enough to signify meaningful progress toward our goal of full EPMC-based rates.

PG&E's proposal, as supported by DRA and CAL-SLA, is the only one which conforms to our stated guideline cap for revenue allocation. In D.90-12-066, we stated: "For future revenue allocations, we expect parties who urge us to depart from our guideline cap of 5% to present specific evidence demonstrating that such departures are warranted by the nature of the demand of agricultural customers for electric service." None of the parties' proposed alternatives to the 5% cap have been shown to be warranted or required by the nature of agricultural demand or any other factors presented in the record.

Both FEA and CLECA propose caps higher than our 5% guideline, yet neither has presented satisfactory evidence justifying an overriding need to deviate from our guideline. FEA, with its 10% cap proposal patterned after a phase-in plan which we previously adopted for a small sample of industrial customers, failed to show the potential effects of applying the same plan to all agricultural customers. CLECA's proposal for a 7% cap is more modest, but it too fails to justify a basis to deviate from our 5% guideline.

We recognize that the total system increase at issue this year of less than 3% is much less than the 10% system increase we were confronted with last year. We agree with FEA and CLECA that the milder increase affords an opportunity to make progress toward EPMC. We also view the milder increase as an opportunity to provide all customers some relief from sharply escalating rates. Accordingly, our decision favoring a 5% cap goes farther than the 3.5% cap we adopted last year toward our goal of full EPMC-based rates. A 5% cap strikes a proper balance between our goal to progress toward a system of cost-based rates, yet to avoid undue rate impacts which could occur if agricultural customers were moved too quickly toward full EPMC-based rates. We disagree with FEA and CLECA only over the magnitude, but not the direction in which interclass revenue allocation should move.

We do not believe that the three principal reasons AECA and CFB cite justify their proposal to halt further progress toward EPMC rates and limit agricultural rate increases to SAPC. We will address, in turn, each of the major arguments AECA and CFB present and explain why they fail to support their proposal.

B. Proximity of Agricultural Rates to EPMC[1]

AECA's arguments regarding the proximity of agricultural rates to EPMC may be analyzed in two parts. One involves AECA's findings on how far agricultural rates deviate from EPMC targets. The other involves the implications of these findings on what action the Commission should take relative to rate caps.

AECA's arguments raise the question of what standard of proof is required to warrant the finding alleged by AECA that a "dark cloud of uncertainty" has been cast over our currently held

1 Our discussion excludes any references to the Area Cost Study which is stricken from the record, as previously ruled. (See Section 4b above.) Any references in the following discussion to the term 'Study' refer only to the Agricultural Rates Cost Study, which was admitted into evidence.

beliefs regarding agriculture's proximity to EPMC. AECA also raises a related issue of what degree of caution we should exercise in light of this uncertainty in terms of revenue allocation in this proceeding.

We conclude AECA has failed to show that there is sufficient uncertainty relative to EPMC targets to justify a complete halt in further progress toward our goal of EPMC-based rates. AECA does not have enough confidence in its assumptions to propose they be adopted in this proceeding, but yet is convinced that they "highlight" the "weak foundation" upon which previous agricultural class EPMC estimates were based. AECA seeks to use the assumptions to challenge existing beliefs and Commission goals regarding EPMC targets, yet refuses to be held to standard of proof as to the credibility of the assumptions beyond mere speculation.

The Agricultural Rates Cost Study's sensitivity adjustments as used by AECA provide no plausible basis to doubt PG&E's computations of EPMC cost targets. Ratemaking has never been an exact science, and we do not require 100% certainty to establish reasonable revenue allocation policies. At best, AECA has shown that there is merely a possibility that present EPMC targets for agriculture may be wrong. AECA is unable to determine the likelihood of that possibility, or of alternative possibilities that agricultural rates may be even further away from EPMC than we now believe. While AECA urges us to "move cautiously," it fails to assess the risk of harm to other classes if we were to act on its premise that agriculture is already close to EPMC and that premise turned out to be wrong.

The credibility of AECA's findings based on the Agricultural Rates Cost Study is questionable given that the Study itself reaches contrary conclusions to those of AECA witness Dr. Pflaum. Dr. Pflaum's explanation is unsatisfying as to why he disagreed with the Study's findings on EPMC targets. Dr. Pflaum claimed the Study's contrary conclusion was incorrect because of an error made in the study relative to the allocation of transmission and distribution loads. On the basis of this alleged error, Dr. Pflaum believes the Study's conclusion that the agricultural class was at least 20% below the EPMC target would no longer hold (Tr. 1396-7).

Yet the error noted by Dr. Pflaum did not occur in the Study. Rather, the error related to PG&E's adopted GRC methodology. (TURN Brief, p. 3.) The Study acknowledged the alleged error, noting that the current methodology in PG&E's GRC "probably does not accurately reflect how classes contribute to peak demands...and so, does not allocate marginal T&D capacity costs on the basis of true peak demand responsibility." (Exh. 117, pp. II-14 and II-15.) The study compensated for this uncertainty by testing the sensitivity of an assumed load diversity adjustment factor of 2.0. Yet, even at this level, the agricultural class still would require a 20% increase to reach full EPMC based on the study. Dr. Pflaum used the same diversity factor as did the Study in his own testimony.

Accordingly, the authors of the Study were well aware of the perceived error noted by Dr. Pflaum in reaching their conclusion that for every sensitivity tested, agriculture is below an EPMC allocation by a significant margin. On this basis, we see no reason for the Study's authors to "moderate" their conclusion "in light of this additional evidence," as Dr. Pflaum argues, since their conclusion already incorporates such evidence.

Dr. Pflaum reaches a different conclusion from the Study's authors because Dr. Pflaum assumed the joint occurrence of five of the sensitivity assumptions tested in the Study. The Study, by contrast, based its conclusions on the separate occurrence of each assumption independently. Dr. Pflaum was unable to explain why the authors did not choose to combine the effects of sensitivity analyses as he had done (Tr. 1467), yet he believed the combining of the assumptions was "the crucial next step" in determining the EPMC target. While no single assumption tested in the study reduces agriculture's distance from EPMC below 20%, the additive effect of five of the assumptions occurring simultaneously theoretically lowers the EPMC target to just under 5%, as computed by Dr. Pflaum.

Dr. Pflaum argued that his sensitivity assumptions were reasonable within the timeframe of the next GRC. Yet he was unable to quantify the likelihood of occurrence of any single factor (Tr. 1461-62), let alone the simultaneous convergence of five factors, as required by his conclusion. Instead, he merely stated there was "some record for some of the changes like load diversity". (Tr. 1462.) The Study itself, however, is ambivalent as to the likelihood of a higher load diversity, stating, "while ...a high diversity adjustment may be appropriate, other characteristics may lower that expectation." Dr. Pflaum's analysis was based on changes that theoretically brought agriculture closer to EPMC. He did not make any study of the likelihood that other assumptions could move agriculture in the opposite direction (Tr. 1462), or result in no change.

Our review of Dr. Pflaum's sensitivity analysis, as described previously, convinces us that each of his assumptions is based largely on speculation. Dr. Pflaum's suggestion that the agricultural class is within 4.6% of EPMC would require not only that each conjectured event must occur, but they all must occur simultaneously, and in the right direction. Yet Dr. Pflaum presented no joint probability analysis to demonstrate the likelihood of all of these factors converging at the same time, nor any probability distribution analysis as to the relative likelihood of other combinations of events converging which may produce results in the opposite direction.

Accordingly, we cannot conclude that the agricultural study assumptions support Dr. Pflaum's conclusion that existing EPMC targets should be seriously questioned. His analysis was not fairly balanced to give consideration to the likelihood that his assumptions might not be adopted by the Commission or that sensitivities in the opposite direction might increase the EPMC target. He did not explain satisfactorily why he reached an opposite conclusion from the agricultural study itself that none of the sensitivities significantly reduced the EPMC target beyond 20%. He was unable to provide a satisfactory assessment as to whether any of the sensitivities would likely apply during the period covered by this decision.

The fact that assumptions can be conceived which would theoretically bring agricultural rates closer to EPMC provides no sound evidentiary basis to doubt the evidence presented by other parties as to the EPMC targets for agriculture, or to warrant a delay in further progress toward our revenue allocation goals on the basis of such mere speculation.

ACEA's conclusions drawn from the agricultural study provide no valid reason for us to deviate from the observation we made shortly after the release of the agricultural study in our 1990 ECAC decision:

> "Notwithstanding the recent release of the agricultural rate study ordered in the GRC decision (a study which has yet to be formally considered by the Commission), we are presented with no basis in this record for retreating from the use of marginal costs which were considered and adopted in the GRC and which have been updated in this proceeding."

AECA implies that unless we adopt its rate proposal to cap agriculture's rate increase at SAPC, we will fail to "move cautiously" in progressing toward our goal of full EPMC for the agricultural class. We disagree. Our adoption of a cap of 5% above SAPC represents a reasonably cautious approach under the circumstances.

We note that in the 1990 ECAC proceeding, CFB made a similar argument that the Commission might "overshoot" the EPMC target if it moves too quickly towards current EPMC estimates, given uncertainty over EPMC measurements. In response to that argument, we stated that the 3.5% cap which we then adopted could scarcely be considered a "rush" to full EPMC when a 58% class increase would have been required for a full EPMC calculation.

The 2.73% SAPC increase estimated in this proceeding is significantly smaller than the 10.59% increase in system revenue adopted in last year's ECAC proceeding. Accordingly, our adoption of a 5% cap applied to a smaller SAPC increase would result in a more modest overall impact on agricultural rates, compared to the increases we adopted in last year's ECAC.

Even if our decision in this proceeding were to be influenced by the possibility we would adopt reduced EPMC allocation targets in PG&E's 1993 GRC, we would still conclude that a rate cap of SAPC plus 5% is mild enough to accommodate the risk of error in our measurement of the EPMC target. Even if PG&E's calculation were overstated in showing that the agricultural class would require a 42% rate increase to meet its EPMC target, it still provides a substantial margin of error when compared with a rate cap of 5% which yields a rate increase of only 7.77% for agriculture.

In short, we conclude that AECA and CFB have failed to provide in this proceeding any credible challenge to the evidence presented by other parties as to the substantial distance of the agricultural class from its EPMC target.

C. Conjunctive Water Use Policies

AECA has not demonstrated that setting agricultural rates above SAPC will be in conflict with state conjunctive use water policies. While we acknowledge the importance of sound conjunctive use policies, especially during the drought, we believe that cost-based electric rates will not detract from economic decisions on the allocation between scarce ground and surface water supplies. Although AECA presents testimony on the effects of the drought on conjunctive use of water supplies, it does not quantify the demand elasticity of electric usage for groundwater pumping as a result of changes in agricultural rates. AECA's witness, Dr. Archibald computed the increased expenditures which would result during 1992 from greater drought-related groundwater pumping. But she did not demonstrate any adverse changes in the conjunctive allocation of water during 1992 caused merely by adopting agricultural rates capped at SAPC plus 5% instead of AECA's proposal. Dr. Archibald states "at some point" costs of water-saving measures exceed the value of risk reduction to farmers. But AECA fails to show that rates set at SAPC is that point. Indeed, TURN convincingly raises the specter that there may be another point of overstimulating demand for groundwater that unbalances conjunctive use in the opposite direction. Clearly, the most cautious stance we can take is to impose cost-based signals as a basis to make water allocation decisions.

D. <u>Economic Hardship</u>

The arguments of AECA and CFB relative to hardship require us to resolve a number of questions. First, does hardship exist within the agricultural class? Second, is revenue allocation an appropriate vehicle to address financial hardship concerns? Third, if so, how do we weigh the differing degrees of hardship experienced by customers within the agricultural class or relative to hardship among nonagricultural customers? Fourth, if financial hardship is properly addressed through revenue allocation, is the rate cap proposed by AECA and CFB the correct limit to address concerns over financial hardship?

As to the first question, we conclude that AECA and CFB have satisfactorily demonstrated that significant financial hardship will likely be experienced to varying degrees among at least some agricultural customers. However, not all agricultural customers were shown to have experienced hardship.

As to the second question, in the past, we have taken potential financial hardship into account in a general sense by imposing rate caps on the allowable increase to customers which would otherwise result from the rate shock of a sudden full EPMC allocation. We do not, however, view revenue allocation subsidies as an appropriate tool with which to remedy pre-existing financial hardships on a class basis. While we sympathize with the plight of all customers who have suffered various financial hardships, we believe that other social and economic remedies besides revenue allocation are more effective in targeting assistance to the proper individuals.

As to the third question, AECA has presented evidence to indicate the agricultural class is impacted more significantly in terms of usage increases than is any other single class as a result of the drought. Yet questions remain as to the relative financial harm that individuals within other customer classes have suffered as a result of the drought, the 1990 freeze, or other factors, and how such harm should be weighed in determining the competing needs of agricultural customers for rate concessions.

As to the fourth question, given the considerations already discussed, we do not believe that a rate increase of 7.77%, reflecting a cap of SAPC plus 5%, imposes an unreasonable financial burden on the agricultural class. This increase is less than the amount we required agricultural customers to absorb last year when they were suffering under financial hardships. Both AECA and CFB are willing to accept an increase of 2.8% in agricultural rates.

AECA seeks to link increased electric usage due to groundwater pumping by agriculture with "rate shock." AECA argues that a 7% rate increase for agriculture could "translate" into 50% higher electricity expenditures between 1990 and 1992 given expected increases in groundwater pumping and greater lift requirements to access water due to continued withdrawal. While we do not question AECA's estimates of expenditure impacts, we do disagree with its attempts to link such expenditure levels with the results of our adopted revenue allocation.

Increased expenditures due to higher electricity consumption will occur under the proposals put forward by all parties, including AECA and CFB. Accordingly, we consider it unfair to "translate" PG&E's proposed 7% increase into 50% higher costs without acknowledging that the 2.8% increase proposed by AECA and CFB would likewise "translate" into correspondingly higher total costs. We believe a proper evaluation of the merits of the AECA and CFB rate impact argument requires a fair comparison of its relative effects compared to competing proposals. When we make this evaluation, we note that there is only a 5% difference between the rates proposed by AECA and CFB versus PG&E.

Even if we factor in a 33% increase in electricity usage by agricultural customers as AECA assumes, the incremental difference in customer costs between PG&E's position and AECA and CFB's position is only an additional 1.65% (i.e., 33% usage increase * 5% unit rate increase). Based upon the rates we have imposed on agricultural customers in last year's ECAC proceeding, we do not consider increases of this magnitude to constitute "rate shock" or to be unreasonable.

E. Requirements of AB 2236

Notwithstanding our conclusion that a revenue allocation cap of SAPC plus 5% is reasonable, based upon the evidence presented in this case, our adopted revenue allocation must conform to the provisions of AB 2236. AB 2236 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."

Accordingly, in compliance with AB 2236, we will cap our revenue allocation to agricultural customers at the system average increase, as proposed by AECA and CFB. We will adopt an EPMC allocation for the remaining customer classes. We have incorporated the marginal energy costs adopted in D.91-11-056 in our EPMC allocations. Our adopted revenue allocations and resulting rate impacts are presented in Appendices A and B of this decision.

Although the ALJ's PD proposed to leave this proceeding open for changes in adopted rates after expiration of the AB 2236 restrictions, we are closing this phase of the proceeding, effective with this order. The rates we authorize by this order will remain in effect until PG&E's next regularly scheduled rate revision following expiration of AB 2236. This resolution avoids any potential disruptions caused by an unscheduled round of rate changes and is consistent with our goal of rate stability.

The revenue allocation criteria we adopt in this order are dictated solely by the provisions of AB 2236. Accordingly, our action sets no precedent for limiting further progress toward EPMC in future rate proceedings.

Findings of Fact

1. In an interim decision in this proceeding, we granted PG&E's request to defer the revenue adjustments adopted in this proceeding and to consolidate them with pending adjustments in other proceedings to allow a single set of rate changes on January 1, 1992.

2. All parties agreed to use PG&E's illustrative revenue increase of $200 million as a basis to analyze revenue allocation criteria in this proceeding.

3. Appendices A and B of this decision sets forth the changes in adopted electric department revenue requirement in the amount of $158,437,000 to become effective January 1, 1992.

4. PG&E's uncontested proposal for a rate floor of SAPC minus 5% avoids potential rate distortions which could otherwise occur with a no-decrease floor.

5. The parties reached a consensus resolution as to commercial/industrial intraclass rate design principles, as embodied in Exhibit 122.

6. No party contested PG&E's other proposed intraclass rate design treatment.

7. No party contested PG&E's proposed consolidation of Rate Schedules A-11 and E-19 to avoid potential for misleading price signals.

8. All parties agreed that at least some portion of the rate increase subject to this decision should be allocated to all customer classes except streetlighting, which should receive a decrease.

9. All parties agreed that the revenue allocations should incorporate caps to limit the potentially adverse rate impacts on agricultural customers.

10. The relative impacts of parties' differences with respect to revenue allocation caps are set forth in Exhibit 116, and presented in Appendix C of this decision.

11. PG&E presented marginal cost calculations indicating agricultural customers would require a 42.26% rate increase in this proceeding to achieve full EPMC, assuming a 2.73% system average increase.

12. All parties except for CFB and AECA accepted PG&E's marginal cost calculations as reasonable.

13. All parties, except CFB and AECA, have recommended that at least some progress be made towards reducing the variance between current allocations and full EPMC for all classes.

14. The Agricultural Rates Cost Study concluded that agricultural rates remained at least 20% below EPMC target under all scenarios which it tested.

15. AECA failed to demonstrate a reasonable doubt that agricultural rates are significantly below EPMC targets.

16. AECA failed to prove that agricultural rates subject to a cap of 5% above SAPC would be detrimental to conjunctive use water policies.

17. Increased expenditures due to higher electricity consumption occur under all parties' proposals, and are independent of revenue allocation differences.

18. The difference between the rate proposal of AECA/CFB and that of PG&E is 5%.

19. Customers within all classes are suffering financial hardship to varying degrees.

20. To the extent that a customer class is allocated a revenue responsibility which is less than its full EPMC responsibility, the class is subsidized by one or more of the remaining classes.

21. Assembly Bill (AB) 2236, enacted subsequent to hearings in this proceeding, prohibits rate increases exceeding system average change for electric service to agricultural customers within our jurisdiction prior to June 1, 1992.

22. The rates set forth in Appendices A and B incorporate the consolidated revenue requirement adjustment shown in Appendix C and the revenue allocation criteria which are adopted by this order.

Conclusions of Law

1. PG&E's proposed marginal energy costs are reasonable, and should be adopted for revenue allocation purposes.

2. The uncontested proposals of PG&E in this proceeding relative to rate floors, intraclass rate design issues, and the consolidation of Schedules A-11 and E-19 and reasonable and should be adopted.

3. We should continue to progress toward full EPMC rates for all customer classes to the extent permitted by law and subject to appropriate rate caps.

4. AECA and CFB failed to justify that a complete halt in progress toward our goal of EPMC rates is warranted due to the factors presented in their testimony.

5. FEA and CLECA failed to justify that we should adopt a rate cap for agriculture in excess of our stated guideline of 5% above system average.

6. Since the system increase we adopt in this year's proceeding is substantially less than what we adopted last year, there is greater flexibility to make progress toward EPMC-based rates without harsh rate increases.

7. Absent the requirements of AB 2236, it would be reasonable to adopt a cap of 5% above SAPC for the agricultural class in this proceeding.

8. Given the restrictions imposed by AB 2236, a revenue allocation should be adopted for the agricultural class which equates to the system average increase in rates.

9. The remaining shortfall in revenue resulting from the rate cap imposed on agricultural customers should be recovered from other classes based on an EPMC allocation.

10. PG&E should be authorized to implement the consolidated revenue requirement shown in Appendices A and B effective January 1, 1992 by filing rate schedules incorporating the rates in Appendix D.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company is authorized and directed to file with this Commission on or after the effective date of this order, and at least five days prior to their effective date, revised tariff schedules for electric rates as set forth in Appendices A and B.

2. The revised tariff schedules shall become effective on or after January 1, 1992 and shall comply with General Order 96-A. The revised tariffs shall apply to service rendered on or after their effective date.

This order is effective today.

Dated December 18, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
JOHN B. OHANIAN
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

NEAL J. SHULMAN, Executive Director

APPENDIX A
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF MARGINAL COSTS

Marginal Energy Costs	Summer Peak (c/kWh)	Summer Partial-Peak (c/kWh)	Summer Off-Peak (c/kWh)	Winter Partial-Peal (c/kWh)	Winter Off-Peak (c/kWh)	Annual (c/kWh)
Generation	2.8070	2.1820	1.9970	2.2980	1.8740	2.1100
Transmission	3.2352	2.5825	2.3943	2.7022	2.2643	2.5092
Distribution						
Primary	3.3869	2.6810	2.4636	2.8213	2.3257	2.5937
Secondary	3.5096	2.7487	2.5009	2.9136	2.3587	2.6481

Marginal Capacity Costs	($/kW-yr)	ERI's	
Generation	$56.17	1992	0.400
ERI (1992-1997)	0.560	1993	0.400
ERI Adjusted	$31.46	1994	0.420
Transmission	$31.80	1995	0.454
Distribution		1996	0.716
Primary	$53.00	1997	0.971
Secondary	$6.87	Average	0.560

Marginal Customer Costs

($/Customer-yr)	Transmission	Primary	Secondary
Residential			$100.37
Small Light and Power			$265.06
Medium Light and Power		$1,533.36	$1,278.83
E-19 Class	$50,207.82	$9,982.09	$11,574.47
E-20 Class	$50,207.82	$9,982.09	$14,800.29
Agricultural			$438.83
Streetlighting			$187.20

APPENDIX A
TABLE 2-A
PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED CLASS ALLOCATIONS
Effective January 1, 1992

	A	B	C	D	E	F	G	H	I	J	K
	Class	Total Sales (MWh)	Present Revenue at 5/1/91 Rates $	Present Revenue Full EPMC $	% Change	Proposed Revenue Full EPMC $	% Change	Proposed Revenue SAPC $	% Change	Proposed Revenue Capped EPMC $	% Change
Line											
1	Residential	23,833,774,764	2,788,215,390	2,706,610,665	(2.93)	2,767,981,641	(0.73)	2,851,362,150	2.26	2,830,902,359	1.53
2	Agricultural	3,419,200,000	390,126,672	541,481,778	38.80	553,532,694	41.89	398,883,980	2.24	398,884,076	2.24
3	Streetlighting	293,703,508	43,458,286	42,000,773	(3.35)	42,533,476	(2.13)	44,022,705	1.30	42,533,476	(2.13)
4	Small L&P	7,409,130,727	976,438,502	994,578,160	1.86	1,016,906,769	4.14	998,372,377	2.25	1,039,735,178	6.48
5	Medium L&P	14,752,865,542	1,427,047,965	1,376,584,658	(3.54)	1,407,931,101	(1.34)	1,459,492,530	2.27	1,457,010,695	2.10
6	E-19 Class	4,598,593,928	449,670,574	434,485,506	(3.38)	444,159,682	(1.23)	459,675,189	2.22	436,652,583	(2.90)
7	E-20 Class Tariff	15,597,458,474	1,165,289,331	1,144,505,180	(1.78)	1,167,681,234	0.21	1,188,917,664	2.03	1,195,008,248	2.55
8	E-20 Contracts	1,227,922,806	84,108,290	84,108,290	0.00	82,220,454	(2.24)	82,220,454	(2.24)	82,220,454	(2.24)
9	Total E-20 Class	16,825,381,280	1,249,397,621	1,228,613,470	(1.66)	1,249,901,688	0.04	1,271,138,118	1.74	1,277,228,702	2.23
10	TOTAL SYSTEM	71,132,649,749	7,324,355,010	7,324,355,010	(0.00)	7,482,947,050	2.17	7,482,947,050	2.17	7,482,947,068	2.17
11	TOTAL INCREASE					158,592,039		158,592,039		158,592,058	5/

1/ This table shows net revenues. Net revenues include non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) load management, UCB, and nonfirm service discounts, (f) power factor revenues (g) CCSF Hetch Hetchy Credits, (h) Residential A/C load control credit and master meter discounts, and (i) URA surcharge revenues.

2/ Standby revenues and marginal costs are included in interclass revenue allocations, but excluded from intraclass revenue allocations. For adopted revenues, standby demands are priced at the proposed maximum demand charge.

3/ E-20 Class and System sales exclude energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to Net Revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1. The total increase in allocated revenues excluding special contracts is 2.74% rather than 2.73%.

5/ Streetlight revenues at present and proposed rates reflect facility charges at the levels adopted in PG&E's 1990 GRC for the ECAC forecast period.

6/ The E-19 allocation shown above results from the application of guidelines for interclass and intraclass allocation adopted in the decision. The effective allocation to E-19 is somewhat different from what is shown since it depends on billing the A-11 and E-19 billing determinants at the combined rates.

APPENDIX A
TABLE 2-B
PACIFIC GAS AND ELECTRIC COMPANY
ILLUSTRATIVE CLASS ALLOCATIONS
USING 5% CAP ON AGRICULTURAL ALLOCATION
Effective January 1, 1992

Line	A Class	B Total Sales (MWh)	C Present Revenue at 5/1/91 Rates $	D Present Revenue Full EPMC $	E % Change	F Proposed Revenue Full EPMC $	G % Change	H Proposed Revenue SAPC $	I % Change	J Proposed Revenue Capped EPMC $	K % Change
1	Residential	23,833,774,764	2,788,215,390	2,706,610,665	(2.93)	2,767,981,641	(0.73)	2,851,362,150	2.26	2,823,031,284	1.25
2	Agricultural	3,419,200,000	390,126,672	541,481,778	38.80	553,532,694	41.89	398,883,980	2.24	418,229,802	7.20
3	Streetlighting	293,703,508	43,458,286	42,000,773	(3.35)	42,533,476	(2.13)	44,022,705	1.30	42,533,476	(2.13)
4	Small L&P	7,409,130,727	976,438,502	994,578,160	1.86	1,016,906,769	4.14	998,372,377	2.25	1,036,879,455	6.19
5	Medium L&P	14,752,865,542	1,427,047,965	1,376,584,658	(3.54)	1,407,931,101	(1.34)	1,459,492,530	2.27	1,454,413,973	1.92
6	E-19 Class	4,598,593,928	449,670,574	434,485,506	(3.38)	444,159,682	(1.23)	459,675,189	2.22	436,640,427	(2.90)
7	E-20 Class Tariff	15,597,458,474	1,165,289,331	1,144,505,180	(1.78)	1,167,681,234	0.21	1,188,917,664	2.03	1,191,589,772	2.26
8	E-20 Contracts	1,227,922,806	84,108,290	84,108,290	0.00	82,220,454	(2.24)	82,220,454	(2.24)	82,220,454	(2.24)
9	Total E-20 Class	16,825,381,280	1,249,397,621	1,228,613,470	(1.66)	1,249,901,688	0.04	1,271,138,118	1.74	1,273,810,226	1.95
10	TOTAL SYSTEM	71,132,649,749	7,324,355,010	7,324,355,010	(0.00)	7,482,947,050	2.17	7,482,947,050	2.17	7,485,538,643	2.20
11	TOTAL INCREASE					158,592,039		158,592,039		161,183,633	5/

1/ This table shows net revenues. Net revenues include non-allocated revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) negotiated contracts, (d) standby charges, (e) load management, UCB, and nonfirm service discounts, (f) power factor revenues (g) CCSF Hetch Hetchy Credits, (h) Residential A/C load control credit and master meter discounts, and (i) URA surcharge revenues.

2/ Standby revenues and marginal costs are included in interclass revenue allocations, but excluded from intraclass revenue allocations. For adopted revenues, standby demands are priced at the proposed maximum demand charge.

3/ E-20 Class and System sales exclude energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to Net Revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1. The total increase in allocated revenues excluding special contracts is 2.74% rather than 2.73%.

5/ Streetlight revenues at present and proposed rates reflect facility charges at the levels adopted in PG&E's 1990 GRC for the ECAC forecast period.

6/ The E-19 allocation shown above results from the application of guidelines for interclass and intraclass allocation adopted in the decision. The effective allocation to E-19 is somewhat different from what is shown since it depends on billing the A-11 and E-19 billing determinants at the combined rates.

APPENDIX A
TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
INTRACLASS NET REVENUE ALLOCATION 1/2/3/
Effective January 1, 1992

	A Class/Rate Schd	Volt Lvl	B Sales	C Average Marginal Cost $	D Net 5/1/91 Revenue $	E Average 5/1/91 Rates $	F Present Revenue Full EPMC $	G % Change	H Proposed Revenue Full EPMC $	I Average Rates $	J % Change	K Proposed Revenue Capped EPMC $	L Average Rates $	M % Change
	RESIDENTIAL:													
1	E-1	S	21,264,532,849	0.07195	2,535,339,367	0.11923	2,604,302,661	(2.93)	2,663,429,662	0.11697	(0.73)	2,574,171,263	0.12106	1.53
2	EL-1	S	1,506,391,062		147,653,790	0.09802						149,868,469	0.09949	1.50
3	E-7	S	1,062,373,233	0.05735	103,976,671	0.09680	101,208,256	(2.66)	103,427,235	0.09628	(0.53)	105,659,836	0.10040	1.62
4	E-8	S	10,477,620	0.06115	1,206,822	0.11509	1,031,770	(14.43)	1,055,313	0.10072	(12.48)	1,164,106	0.11110	(3.46)
5	Standby				37,740		67,756	79.53	69,230		83.44	38,684		2.50
6	TOTAL		23,833,774,764	0.07131	2,788,215,390	0.11699	2,706,610,665	(2.93)	2,767,961,641	0.11614	(0.73)	2,830,902,359	0.11878	1.53
	AGRICULTURAL													
7	AG-1 A	S	258,555,914	0.21118	53,102,836	0.20538	87,975,134	65.67	89,914,124	0.34776	69.32	54,282,988	0.20995	2.22
8	AG-RA	S	23,140,896	0.13497	3,066,567	0.13249	5,185,060	69.08	5,296,824	0.22885	72.73	3,132,232	0.13533	2.14
9	AG-VA	S	42,166,694	0.12866	5,546,965	0.13155	9,001,624	62.28	9,196,227	0.21809	65.79	5,666,413	0.13438	2.15
10	AG-4A	S	114,962,823	0.13556	15,249,249	0.13266	25,841,717	69.46	26,399,175	0.22965	73.12	15,576,209	0.13550	2.14
11	AG-5A	S	82,054,976	0.06334	8,463,949	0.10339	11,238,306	32.47	11,486,053	0.13998	35.39	8,671,761	0.10568	2.21
12	AG-1 B	S	542,400,262	0.11660	83,468,186	0.15389	101,940,460	22.13	104,210,331	0.19213	24.85	85,336,103	0.15733	2.24
13	AG-RB	S	34,824,587	0.10688	4,525,606	0.12995	5,993,557	32.44	6,126,215	0.17592	35.37	4,626,321	0.13285	2.23
14	AG-VB	S	27,894,768	0.10711	3,581,043	0.12836	4,857,106	35.63	4,964,567	0.17797	38.63	3,660,737	0.13123	2.23
15	AG-4B		403,185,975	0.09665	48,968,287	0.12145	64,613,835	31.95	66,047,516	0.16381	34.88	50,061,317	0.12416	2.23
16	AG-4C	S	23,254,426	0.12496	2,861,936	0.12307	4,720,263	65.04	4,827,410	0.20759	68.68	2,925,560	0.12581	2.22
17	AG-5B		1,817,531,416	0.07292	157,605,379	0.08671	214,412,969	36.04	219,236,969	0.12062	39.11	161,193,231	0.08869	2.28
18	AG-5C	S	49,232,443	0.07156	3,660,856	0.07436	5,668,326	55.36	5,816,656	0.11815	56.89	3,745,066	0.07607	2.30
19	Standby				5,794		10,401	79.52	10,626		83.43	5,936		2.49
20	TOTAL		3,419,200,000	0.09776	390,126,672	0.11410	541,481,778	38.80	553,532,694	0.16189	41.89	398,884,076	0.11666	2.24
	STREETLIGHTS /6													
21	LS-1	S	111,567,348		26,395,276	0.23659						26,031,247	0.23332	(1.38)
22	LS-2	S	166,604,554		14,007,800	0.08408						13,464,191	0.08082	(3.88)
23	LS-3	S	2,336,742		182,536	0.07812						174,914	0.07485	(4.18)
24	OL-1	S	13,194,864		2,872,670	0.21771						2,830,936	0.21455	(1.45)
25	TOTAL		293,703,506	0.05163	43,458,284	0.14797	42,000,773	(3.35)	42,533,476	0.14482	(2.13)	42,533,476	0.14482	(2.13)
	SMALL L&P													
26	A-1	S	7,095,935,207	0.08416	944,854,307	0.13316	962,900,725	1.91	984,528,822	0.13875	4.20	1,006,901,660	0.14190	6.57
27	A-6	S	197,208,000	0.06743	18,776,515	0.09522	18,543,896	(1.25)	18,960,262	0.09614	0.97	19,384,566	0.09830	3.23
28	A-15	S	1,969,164	0.19103	464,901	0.23609	690,563	48.54	703,930	0.35748	51.42	508,505	0.25823	9.38
29	TC-1	S	114,018,356	0.06707	12,271,803	0.10763	12,316,189	0.36	12,583,177	0.11036	2.54	12,869,676	0.11287	4.87
30	Standby				66,976		127,797	85.28	130,578		89.31	70,749		2.57
31	TOTAL		7,409,130,727	0.08322	976,436,502	0.13179	994,578,160	1.86	1,016,906,769	0.13725	4.14	1,039,735,178	0.14033	6.48
	MEDIUM L&P													
32	A-10		8,997,480,865	0.06229	921,516,441	0.10242	904,178,994	(1.88)	924,708,799	0.10277	0.35	945,597,681	0.10510	2.61
33	A-11		5,755,384,647	0.05075	505,212,610	0.08778	471,863,649	(6.60)	482,666,491	0.08386	(4.46)	511,066,496	0.08880	1.16
34	Standby				318,914		542,015	69.96	553,810		73.65	326,516		2.38
35	TOTAL		14,752,865,542	0.05781	1,427,047,965	0.09673	1,376,584,658	(3.54)	1,407,931,101	0.09543	(1.34)	1,457,010,695	0.09876	2.10
	E-19 CLASS													
36	E-19	T	16,839,306	0.07749	1,532,624	0.09101	2,105,067	37.35	2,161,687	0.12837	41.04	1,642,376	0.09753	7.16
37	E-19/25	P	501,455,729	0.05099	42,092,001	0.08394	40,448,041	(3.91)	41,414,758	0.08259	(1.61)	42,433,463	0.08462	0.81
38	E-19/25	S	4,024,392,039	0.05946	400,684,106	0.09956	385,867,674	(3.70)	394,382,292	0.09799	(1.57)	386,931,912	0.09614	(3.43)
39	A-RTP-19	S	55,706,852	0.06162	4,422,254	0.07938	4,688,740	6.03	4,795,019	0.08608	8.43	4,687,336	0.08414	5.99
40	Standby				939,587		1,376,964	46.45	1,405,927		49.63	957,494		1.91
41	TOTAL		4,598,593,928	0.05871	449,670,574	0.09778	434,485,506	(3.38)	444,159,682	0.09659	(1.23)	436,652,583	0.09495	(2.90)
	E-20 CLASS													
42	E-20	T	3,625,109,851	0.03542	203,658,399	0.05618	197,481,880	(3.03)	201,279,900	0.05552	(1.17)	207,020,602	0.05711	1.65
43	E-20	P	7,226,935,661	0.04673	543,138,893	0.07515	532,078,687	(2.04)	542,752,759	0.07510	(0.07)	557,407,273	0.07713	2.63
44	E-20	S	4,494,275,370	0.05363	391,440,012	0.08710	383,974,906	(1.91)	391,982,809	0.08722	0.14	402,267,590	0.08951	2.77
45	A-RTP-20	P	86,369,949	0.04907	7,067,046	0.08182	6,863,129	(2.89)	7,020,165	0.08128	(0.66)	7,201,044	0.08337	1.90
46	A-RTP-20	S	164,767,843	0.05142	12,963,841	0.07860	13,729,755	5.74	14,042,921	0.08523	8.16	13,991,329	0.08492	7.76
47	Standby				7,001,139		10,376,852	48.22	10,602,861		51.44	7,120,410		1.70
48	E-20 Tariffs		15,597,458,474	0.04604	1,165,269,331	0.07471	1,144,505,180	(1.78)	1,167,681,234	0.07486	0.21	1,195,008,246	0.07662	2.55
49	Contracts:	T	561,801,696	0.03559	42,164,426	0.07505	42,164,426	0.00	40,598,287	0.07226	(3.71)	40,598,287	0.07226	(3.71)
50	Contracts:	P	636,576,351	0.04567	39,955,534	0.06277	39,955,534	0.00	39,830,845	0.06257	(0.31)	39,830,845	0.06257	(0.31)
51	Contracts:	S	29,544,759 ^	0.04646	1,988,330	0.06730	1,988,330	0.00	1,791,322	0.06063	(9.91)	1,791,322	0.06063	(9.91)
52	Total Contracts		1,227,922,806	0.04123	84,108,290	0.06850	84,108,290	0.00	82,220,454	0.06696		82,220,454	0.06696	(2.24)
53	TOTAL E-20		16,825,381,280	0.04607	1,249,397,621	0.07426	1,228,613,470	(1.66)	1,249,901,688	0.07429	0.04	1,277,228,702	0.07591	2.23
54	SYSTEM TOTAL		71,132,849,749	0.06406	7,324,355,010	0.10297	7,324,355,010	(0.00)	7,482,947,050	0.10476	2.17	7,482,947,050	0.10520	2.17
55	Check		71,132,849,749		7,324,355,009		7,324,355,010		7,482,947,060			7,482,947,068		4/
56	TOTAL INCREASE								158,592,041			158,592,060		

1/ This table shows net revenues. Net revenues include non-allocated revenue adjustments from (a) optional TOU meters, (b) Streetlighting and Railway facilities, (c) negotiated contracts, (d) standby charges, (e) UCB, load mgmt, and nonfirm discounts, (f) power factor revenues, (g) CCSF Credits, (h) Residential EC, ES, & ET discounts, and (h) LIRA surcharge revenue.

2/ Standby revenues and marginal costs are included in the interclass, but not the intraclass revenue allocations. Proposed Standby rates are set at the 1/1/92 maximum demand charges.

3/ E-20 Class and System sales exclude energy provided to CCSF customers from Hetch Hetchy.

4/ Percentage changes are relative to Net Revenue at present rates. Class caps, however, are based on changes in allocated revenues excluding special contracts. Allocated revenues exclude the items identified in footnote 1. The total increase in allocated revenues excluding special contracts is 2.74% rather than 2.73%.

5/ Streetlight revenues at present and proposed rates reflect facility charges at the levels adopted in PG&E's 1990 GRC for the ECAC forecast period.

6/ The A-11 and E-19 allocations shown above results from the application of guidelines for interclass and intraclass allocation adopted in the decision. The effective allocations to A-11 and E-19 are somewhat different from those shown, since they depend on billing the A-11 and E-19 billing determinants at the combined rates.

APPENDIX A
TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
INTRACLASS ALLOCATED REVENUE ALLOCATION 1/2/3/
Effective January 1, 1992

	A		B	C	D	E	F	G	H	I	J	K	L	M
	Class/Rate Schdl	Volt Lvl	Sales	Average Marginal Cost $	Allocated 5/1/91 rate Revenue $	Average 5/1/91 Rates $	Allocated Present Rev Full EPMC $	% Change	Allocated Revenue Full EPMC $	Average Rates $	% Change	Allocated Proposed Capped EPMC $	Average Rates $	% Change
	RESIDENTIAL:													
1	E-1	S	21,264,532,649	0.07195	2,568,997,766	0.12081	2,636,606,263	(2.90)	2,696,028,506	0.11840	(0.78)	2,606,120,904	0.12256	1.45
2	EL-1	S	1,508,391,062		148,300,793	0.09848						150,616,472	0.09992	1.49
3	E-7	S	1,062,373,233	0.05738	99,966,196	0.09409	97,194,785	(2.77)	99,300,821	0.09437	(0.66)	101,542,423	0.09540	1.54
4	E-8	S	10,477,620	0.06115	1,205,675	0.11509	1,031,821	(14.43)	1,054,274	0.10062	(12.57)	1,163,067	0.11100	(3.50)
	Standby				37,740		67,756	79.53	69,230		83.44	38,684		2.50
5	TOTAL		23,833,774,764	0.07131	2,818,507,370	0.11826	2,736,902,645	(2.90)	2,798,459,831	0.11733	(0.78)	2,859,360,540	0.11997	1.45
	AGRICULTURAL													
6	AG-1 A	S	256,558,914	0.21118	53,058,881	0.20521	87,931,179	65.72	89,844,032	0.34749	69.33	54,213,496	0.20968	2.18
7	AG-RA	S	23,146,696	0.13497	2,912,611	0.12583	5,031,004	72.74	5,140,460	0.22209	76.50	2,975,890	0.12857	2.18
8	AG-VA	S	42,166,694	0.12888	5,298,770	0.12562	8,751,410	65.22	8,941,847	0.21206	68.82	5,412,033	0.12835	2.18
9	AG-4A	S	114,962,823	0.13558	14,503,315	0.12617	25,095,783	73.03	25,641,867	0.22306	76.80	14,818,922	0.12891	2.18
10	AG-5A	S	82,054,976	0.08334	8,258,208	0.10064	11,012,565	33.35	11,252,207	0.13713	36.25	8,437,916	0.10283	2.18
11	AG-1 B	S	542,400,282	0.11660	83,375,976	0.15372	101,848,252	22.16	104,064,551	0.19186	24.81	85,190,322	0.15706	2.18
12	AG-RB	S	34,824,567	0.10568	4,470,175	0.12836	5,936,126	32.84	6,067,344	0.17423	35.73	4,567,451	0.13116	2.18
13	AG-VB	S	27,894,768	0.10711	3,536,833	0.12675	4,811,898	36.09	4,916,402	0.17625	39.06	3,612,572	0.12951	2.18
14	AG-4B		403,185,975	0.09865	48,408,069	0.12006	64,053,618	32.32	65,447,476	0.16233	35.20	49,461,477	0.12268	2.18
15	AG-4C	S	23,254,426	0.12496	2,818,160	0.12119	4,679,529	66.05	4,781,360	0.20561	69.66	2,879,500	0.12383	2.18
16	AG-5B		1,817,531,416	0.07292	156,625,919	0.08618	213,433,509	36.27	218,077,993	0.11999	39.23	160,034,255	0.08805	2.18
17	AG-5C	S	49,232,443	0.07156	3,646,348	0.07406	5,673,816	55.60	5,797,280	0.11775	58.99	3,725,690	0.07568	2.18
	Standby				5,794		10,401	79.52	10,628		83.43	5,936		2.49
18	TOTAL		3,419,200,000	0.09776	386,915,762	0.11316	538,270,868	39.12	549,964,092	0.16085	42.15	395,335,475	0.11562	2.18
19	STREETLIGHTS	S	290,703,506	0.05163	25,877,529	0.08611	24,420,018	(5.63)	24,951,415	0.08405	(3.58)	24,951,415	0.08495	(3.58)
	SMALL L&P													
20	A-1	S	7,095,936,207	0.08416	943,647,906	0.13298	961,894,416	1.91	982,621,854	0.13848	4.13	1,004,994,512	0.14163	6.50
21	A-6	S	197,208,000	0.05743	16,473,281	0.09087	16,238,682	(1.27)	16,635,560	0.09450	0.88	19,059,854	0.09665	3.16
22	A-15	S	1,969,164	0.19103	360,136	0.19005	605,790	59.36	618,973	0.31433	62.83	423,548	0.21509	11.42
23	TC-1	S	114,018,356	0.06707	12,271,803	0.10763	12,316,189	0.36	12,583,177	0.11036	2.54	12,869,678	0.11287	4.87
24	Standby				68,976		127,797	86.28	130,578		89.31	70,749		2.57
25	TOTAL		7,409,130,727	0.08322	974,842,196	0.13157	992,981,866	1.86	1,014,589,932	0.13694	4.08	1,037,418,341	0.14002	6.42
	MEDIUM L&P													
26	A-10		8,997,480,895	0.06229	919,017,268	0.10224	902,579,841	(1.86)	922,220,899	0.10250	0.25	943,109,581	0.10462	2.32
27	A-11		5,755,384,647	0.05075	503,753,991	0.08753	470,406,030	(6.62)	480,641,419	0.08351	(4.59)	509,059,423	0.08845	1.05
28	Standby				318,914		542,015	69.96	553,810		73.66	326,518		2.38
29	TOTAL		14,752,865,542	0.05761	1,423,990,190	0.09652	1,373,526,886	(3.54)	1,403,415,927	0.09513	(1.44)	1,452,495,522	0.09846	2.00
	E-19 CLASS													
30	E-19	T	16,839,306	0.07749	1,328,898	0.09079	2,101,339	37.44	2,147,066	0.12750	40.43	1,627,757	0.09666	6.47
31	E-19/25	P	501,453,729	0.05099	42,820,724	0.08539	41,176,764	(3.84)	42,072,803	0.08390	(1.75)	43,091,506	0.08593	0.63
32	E-19/25	S	4,024,592,039	0.05946	400,309,675	0.09947	385,493,241	(3.70)	393,881,881	0.09787	(1.61)	386,431,502	0.09602	(3.47)
35	A-RTP-19	S	55,706,862	0.05162	4,364,659	0.07835	4,631,144	6.11	4,731,922	0.08494	8.41	4,624,238	0.08301	5.95
36	Standby				939,587		1,375,964	46.45	1,405,927		49.63	957,494		1.91
37	TOTAL		4,598,590,928	0.05471	449,963,840	0.09785	434,778,472	(3.37)	444,239,590	0.09660	(1.27)	436,732,499	0.09497	(2.94)
	E-20 CLASS													
38	E-20	T	3,625,109,831	0.03542	222,821,823	0.06147	216,646,104	(2.77)	221,359,474	0.06106	(0.66)	227,100,177	0.06265	1.92
39	E-20	P	7,226,936,661	0.04673	564,098,582	0.07806	553,038,348	(1.96)	565,072,902	0.07819	0.17	579,727,416	0.08022	2.77
40	E-20	S	4,494,275,370	0.05363	395,596,590	0.08802	388,131,464	(1.89)	396,577,535	0.08824	0.25	406,862,316	0.09053	2.85
41	A-RTP-20	P	86,369,949	0.04907	7,029,263	0.08139	6,825,346	(2.90)	6,973,671	0.08074	(0.79)	7,154,731	0.08284	1.78
42	A-RTP-20	S	164,767,843	0.05142	12,897,531	0.07828	13,643,444	5.78	13,940,337	0.08461	8.09	13,868,746	0.08429	7.69
48	Standby				7,001,139		10,376,852	48.22	10,602,661		51.44	7,120,410		1.70
43	E-20 Tariff		15,597,456,474	0.04604	1,209,444,726	0.07754	1,186,660,577	(1.72)	1,214,526,760	0.07787	0.42	1,241,853,795	0.07962	2.66
44	Contracts:	T	561,801,896	0.03559	0		0		0			0		
45	Contracts:	P	636,576,351	0.04587	0		0		0			0		
46	Contracts:	S	29,544,759	0.04848	0		0		0			0		
47	Total Contracts		1,227,922,806	0.00000	0		0		0			0		
49	TOTAL		16,825,381,280	0.04607	1,209,444,726	0.07188	1,186,660,577	(1.72)	1,214,526,760	0.07218	0.42	1,241,853,795	0.07381	2.66
50	SYSTEM TOTAL		71,132,649,749	0.06406	7,269,541,336	0.10248	7,269,541,336	(0.00)	7,448,167,577	0.10471	2.18	7,448,167,577	0.10471	2.18
51	Check		71,132,649,749		7,269,541,336	0.10246	7,269,541,336	0.00	7,448,167,577	0.10471		7,448,167,596		4/
52	TOTAL INCREASE								158,626,239			158,626,257		

1/ This table shows allocated revenues. Allocated revenues exclude revenue adjustments from (a) optional TOU meter charges, (b) Streetlighting and Railway facility charges, (c) power factor revenues, (d) the UCB discount, (e) CCSF Hetch Hetchy Power, (f) Residential A/C load control credit and master meter discounts, and (g) LIRA surcharge revenues.

2/ Negotiated contract revenues are excluded from the allocation process and escalated using escalation rates in the contracts.

3/ Standby revenues and marginal costs are included in interclass revenue allocations, but excluded from intraclass revenue allocations.

4/ E-20 Class sales exclude Hetch Hetchy power provided through PG&E to CCSF customers.

5/ Percentage changes are relative to allocated revenue at present rates. Class caps are based on the total system increase excluding special contracts. Intraclass caps are based on class increases without standby revenues.

6/ The A-11 and E-19 allocations shown above results from the application of guidelines for interclass and intraclass allocation adopted in the decision. The effective

A.91-04-003 ALJ/TRP
CACD/lk/2*

APPENDIX A
TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
CALCULATION OF LOW-INCOME RATEPAYER ASSISTANCE (LIRA) SURCHARGE

LIRA Program Costs

Line No.	Description:	A Pre-surcharge Non-LIRA Rate	B LIRA Rate	C Effective Discount (Col A-Col B)	D Billing Determinants	E Low-Income Discount (Col C*Col D)
1	EL-1 Tier 1	0.11080	0.09418	0.01662	1,139,473,553	$18,938,050
2	EL-1 Tier 2	0.13838	0.11762	0.02076	366,364,804	$7,605,733
3	EL-1 Minimum Bill	5.00	4.25	0.75	25,159	$18,869
4	EL-7 Meter Charge	4.40	0.00	4.40	15,528	$68,323
5	EL-8 Customer Charge	13.92	11.83	2.09	90	$188
6	EL-8 Summer	0.11715	0.09958	0.01757	67,193	$1,181
7	EL-8 Winter	0.06695	0.05691	0.01004	37,846	$380
8	Total					$26,632,725
9	LIRA Administrative Costs					$2,436,737
10	Forecast LIRA Account Balance on 12/31/92					($10,713,000)
11	Total LIRA Program Costs					$18,356,462

Sales Subject to LIRA Surcharge

Line No.	Description	
12	Total Forecast Sales (KWh) (Unadjusted for EE discount & includes CCSF power from Hetch Hetchy sales)	71,490,461,984
	Adjustments:	
13	EE Adjustment	63,238,235
14	Low-income forecast period sales (Col D Lines 1,2,6, and 7))	1,505,943,396
15	Low-income forecast period minimum bill sales	552,705
16	Street Light Sales (LS-1, LS-2, LS-3, TC-1)	394,527,000
17	Special Contract Sales	1,227,922,807
18	Total Adjustments	3,192,184,143
19	Total kWh Sales Subject to LIRA Surcharge	68,298,277,841

Calculation of the LIRA Surcharge

Line No.	Description	
20	Total LIRA Program Costs ($)	$18,356,462
21	Total KWh Sales Subject to LIRA Surcharge	68,298,277,841
22	LIRA surcharge ($/KWh)	0.00027

APPENDIX A
TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
ATTRITION YEAR 1992 – CPUC JURISDICTION
ADOPTED REVENUE CHANGES

Line	Rate Element	Adopted Revenue Change $000	Average Rate 1/ c/KWh
1	ECAC/AER/ERAM/LIRA	8,769	0.01233
2	Customer Energy Efficiency	15,360	0.02159
3	Cost of Capital (A.91-05-016)	(24,277)	(0.03413)
4	Attrition Advice Letter	95,139	0.13375
5	Post Retirement Benefits and Other Pensions (PBOPs)	63,601	0.08941
6	Total Adopted Revenue Changes	158,592	0.22295

1/ Calculation of average rates is based on total system sales of 71,132,649,749 MWh.

APPENDIX B
TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED RESIDENTIAL RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-1					
1	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	1
2	ES UNIT DISCOUNT ($/UNIT/MONTH)	$3.00	$3.00	$3.00	$3.00	2
3	ET UNIT DISCOUNT ($/UNIT/MONTH)	$10.74	$10.74	$10.74	$10.74	3
4	ET MINIMUM RATE LIMITER ($/KWH)	$0.05317	$0.05317	$0.05089	$0.05089	4
5	TIER 1 ENERGY ($/KWH)	$0.10924	$0.10924	$0.11107	$0.11107	5
6	TIER 2 ENERGY ($/KWH)	$0.13682	$0.13682	$0.13865	$0.13865	6
	SCHEDULE EL-1 (LIRA)					
7	MINIMUM BILL ($/MONTH)	$4.25	$4.25	$4.25	$4.25	7
8	TIER 1 ENERGY ($/KWH)	$0.09271	$0.09271	$0.09418	$0.09418	8
9	TIER 2 ENERGY ($/KWH)	$0.11615	$0.11615	$0.11762	$0.11762	9
	SCHEDULES E-7 AND EL-7					
10	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	10
11	E-7 METER CHARGE ($/MONTH)	$4.40	$4.40	$4.40	$4.40	11
12	EL-7 METER CHARGE($/MONTH)	$0.00	$0.00	$0.00	$0.00	12
13	ON-PEAK ENERGY ($/KWH)	$0.31251	$0.10330	$0.31738	$0.10478	13
14	OFF-PEAK ENERGY ($/KWH)	$0.09423	$0.07982	$0.09558	$0.08093	14
15	BASELINE DISCOUNT ($/KWH)	$0.02758	$0.02758	$0.02758	$0.02758	15
	SCHEDULE E-8					
16	CUSTOMER CHARGE ($/MONTH)	$13.92	$13.92	$13.92	$13.92	16
17	ENERGY CHARGE ($/KWH)	$0.12212	$0.06994	$0.11742	$0.06722	17
	SCHEDULE EL-8 (LIRA)					
18	CUSTOMER CHARGE ($/MONTH)	$11.83	$11.83	$11.83	$11.83	18
19	ENERGY CHARGE ($/KWH)	$0.10365	$0.05930	$0.09958	$0.05691	19
	SCHEDULES E-A7 AND EL-A7					
20	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	20
21	E-A7 METER CHARGE ($/MONTH)	$4.40	$4.40	$4.40	$4.40	21
22	EL-A7 METER CHARGE($/MONTH)	$0.00	$0.00	$0.00	$0.00	22
23	ON-PEAK ENERGY ($/KWH)	$0.37275	$0.10255	$0.38177	$0.10406	23
24	OFF-PEAK ENERGY ($/KWH)	$0.08482	$0.08003	$0.08529	$0.08108	24
25	BASELINE DISCOUNT ($/KWH)	$0.02758	$0.02758	$0.02758	$0.02758	25
	SCHEDULE E-87					
26	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	26
27	E-87 METER CHARGE ($/MONTH)	$4.40	$4.40	$4.40	$4.40	27
28	CRITICAL ($/KWH)	$0.55087	$0.55087	$0.55856	$0.55856	28
29	HIGH ($/KWH)	$0.31417	N/A	$0.32186	N/A	29
30	MEDIUM ($/KWH)	N/A	$0.09177	N/A	$0.09294	30
31	LOW ($/KWH)	$0.07208	$0.07208	$0.07278	$0.07278	31

APPENDIX B
TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED SMALL L&P RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE A-1					
1	CUSTOMER CHARGE ($/MO.)	$7.50	$7.50	$7.50	$7.50	1
2	POLYPHASE CHARGE ($/MO.)	$1.25	$1.25	$1.25	$1.25	2
3	ENERGY ($/KWH)	$0.13984	$0.11493	$0.14940	$0.12279	3
	SCHEDULE A-6					
4	CUSTOMER CHARGE ($/MONTH)	$7.50	$7.50	$7.50	$7.50	4
5	METER CHARGE ($/MONTH)	$6.20	$6.20	$6.20	$6.20	5
6	POLYPHASE CHARGE ($/MO.)	$1.25	$1.25	$1.25	$1.25	6
7	ON-PEAK ENERGY ($/KWH)	$0.27771		$0.28698		7
8	PART-PEAK ENERGY ($/KWH)	$0.13885	$0.07407	$0.14349	$0.07654	8
9	OFF-PEAK ENERGY ($/KWH)	$0.07221	$0.05555	$0.07462	$0.05741	9
	SCHEDULE A-15					
10	CUSTOMER CHARGE ($/MONTH)	$7.50	$7.50	$7.50	$7.50	10
11	FACILITY CHARGE ($/MONTH)	$7.80	$7.80	$7.80	$7.80	11
12	ENERGY ($/KWH)	$0.16060	$0.14338	$0.18400	$0.16427	12
	SCHEDULE TC-1					
13	CUSTOMER CHARGE ($/MONTH)	$7.50	$7.50	$7.50	$7.50	13
14	ENERGY ($/KWH)	$0.10067	$0.10067	$0.10591	$0.10591	14

APPENDIX B
TABLE 3
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED MEDIUM L&P RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE A-10					
1	CUSTOMER CHARGE ($/MONTH)	$63.00	$63.00	$63.00	$63.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	2
3	PRIMARY DISCOUNT ($/KW/MONTH)	$0.90	$0.90	$0.90	$0.90	3
4	TRANS. DISCOUNT ($/KW/MONTH)	$3.40	$3.40	$3.55	$3.55	4
5	ENERGY CHARGE($/KWH)	$0.09673	$0.07497	$0.09918	$0.07687	5
	SCHEDULES A-11 AND E-14					
6	CUSTOMER CHARGE ($/MONTH)	$63.00	$63.00	$63.00	$63.00	6
7	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	7
8	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	8
9	PRIMARY DISCOUNT ($/KW/MONTH)	$0.90	$0.90	$0.90	$0.90	9
10	TRANS. DISCOUNT ($/KW/MONTH)	$3.40	$3.40	$3.55	$3.55	10
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$11.00		$11.10		11
12	ON-PEAK ENERGY ($/KWH)	$0.11131		$0.11232		12
13	PART-PEAK ENERGY ($/KWH)	$0.08506	$0.06393	$0.08583	$0.06451	13
14	OFF-PEAK ENERGY ($/KWH)	$0.05709	$0.05537	$0.05761	$0.05587	14
15	E-14 ON-PEAK ENERGY ($/KWH)	$0.13757		$0.13881		15

APPENDIX B
TABLE 4
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 FIRM RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-19 T FIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.60		$9.00		3
4	ON-PEAK ENERGY ($/KWH)	$0.10637		$0.11409		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.07220	$0.06173	$0.07744	$0.06621	5
6	OFF-PEAK ENERGY ($/KWH)	$0.05512	$0.05347	$0.05912	$0.05735	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.66285		7
	SCHEDULE E-19 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.50		$10.90		10
11	ON-PEAK ENERGY ($/KWH)	$0.10820		$0.10773		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.07344	$0.06279	$0.07313	$0.06252	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05606	$0.05439	$0.05583	$0.05416	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.14595		$0.15379		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85889		$0.90501		15
	SCHEDULE E-19 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$260.00	$260.00	$260.00	$260.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$11.20		$11.60		18
19	ON-PEAK ENERGY ($/KWH)	$0.11982		$0.11277		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.08133	$0.06953	$0.07654	$0.06544	20
21	OFF-PEAK ENERGY ($/KWH)	$0.06208	$0.06023	$0.05843	$0.05669	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.14595		$0.15379		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.91033		23

APPENDIX B
TABLE 5
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 NONFIRM RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-19 T NONFIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	3
4	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.86		$8.98		5
6	ON-PEAK ENERGY ($/KWH)	$0.10397		$0.11169		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.07057	$0.06034	$0.07581	$0.06482	7
8	OFF-PEAK ENERGY ($/KWH)	$0.05368	$0.05226	$0.05788	$0.05614	8
9	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	9
10	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$6.77200	$6.77200	$6.77200	$6.77200	10
	SCHEDULE E-19 P NONFIRM					
11	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	11
12	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	12
13	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	13
14	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	14
15	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$5.83		$6.97		15
16	ON-PEAK ENERGY ($/KWH)	$0.09975		$0.09928		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.06771	$0.05789	$0.06740	$0.05762	17
18	OFF-PEAK ENERGY ($/KWH)	$0.05168	$0.05014	$0.05145	$0.04991	18
19	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	19
20	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	20
	SCHEDULE E-19 S NONFIRM					
21	CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	21
22	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	22
23	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	24
25	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$5.06		$3.88		25
26	ON-PEAK ENERGY ($/KWH)	$0.11821		$0.11116		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.08024	$0.06860	$0.07545	$0.06451	27
28	OFF-PEAK ENERGY ($/KWH)	$0.06125	$0.05942	$0.05760	$0.05588	28
29	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	29
30	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	30

APPENDIX B
TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 FIRM RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-20 T					
1	CUSTOMER CHARGE ($/MONTH)-FIRM	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.60		$9.00		3
4	ON-PEAK ENERGY ($/KWH)	$0.08351		$0.08485		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.05668	$0.04846	$0.05759	$0.04924	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04327	$0.04196	$0.04397	$0.04265	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.65109		7
	SCHEDULE E-20 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.50		$10.90		10
11	ON-PEAK ENERGY ($/KWH)	$0.10032		$0.10278		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.06809	$0.05822	$0.06976	$0.05965	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05198	$0.05043	$0.05326	$0.05166	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.13106		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85869		$0.88895		15
	SCHEDULE E-20 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$11.20		$11.60		18
19	ON-PEAK ENERGY ($/KWH)	$0.10628		$0.11116		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.07360	$0.06284	$0.07545	$0.06451	20
21	OFF-PEAK ENERGY ($/KWH)	$0.05610	$0.05443	$0.05760	$0.05588	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.13106		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.89418		23

APPENDIX B
TABLE 7
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 NONFIRM RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-20 T NONFIRM					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	3
4	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$3.81		$3.17		5
6	ON-PEAK ENERGY ($/KWH)	$0.08146		$0.08280		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.05527	$0.04725	$0.05618	$0.04803	7
8	OFF-PEAK ENERGY ($/KWH)	$0.04219	$0.04092	$0.04289	$0.04159	8
9	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	9
10	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$6.77200	$6.77200	$6.77200	$6.77200	10
	SCHEDULE E-20 P NONFIRM					
11	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	11
12	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	12
13	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	13
14	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	14
15	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.43		$6.71		15
16	ON-PEAK ENERGY ($/KWH)	$0.09296		$0.09542		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.06310	$0.05395	$0.06477	$0.05538	17
18	OFF-PEAK ENERGY ($/KWH)	$0.04817	$0.04673	$0.04945	$0.04796	18
19	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	19
20	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	20
	SCHEDULE E-20 S NONFIRM					
21	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	21
22	CURTAILABLE METER CHARGE($/MONTH)	$190.00	$190.00	$190.00	$190.00	22
23	INTERUPTIBLE METER CHARGE ($/MONTH)	$200.00	$200.00	$200.00	$200.00	23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	24
25	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$6.28		$5.51		25
26	ON-PEAK ENERGY ($/KWH)	$0.10336		$0.10624		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.07016	$0.05998	$0.07211	$0.06165	27
28	OFF-PEAK ENERGY ($/KWH)	$0.05355	$0.05196	$0.05505	$0.05341	28
29	UFR CREDIT ($/KWH)	$0.00186	$0.00186	$0.00186	$0.00186	29
30	EXCESS ENERGY CHARGE ($/KWH/EVENT)	$8.64933	$8.64933	$8.64933	$8.64933	30

APPENDIX B
TABLE 8
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED REAL TIME PRICING RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE A-RTP PRIMARY					
1	E-20 CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	1
2	OPTIONAL SERVICE CHARGE ($/MONTH)	$275.00	$275.00	$275.00	$275.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	3
4	BASE ENERGY RATE ($/KWH)	$0.00332	$0.00332	$0.00334	$0.00334	4
5	ON-PEAK ENERGY MULTIPLIER	2.1304		2.5818		5
6	PART-PEAK ENERGY MULTIPLIER	2.1304	1.5500	2.5818	1.8944	6
7	OFF-PEAK ENERGY MULTIPLIER	1.5500	1.5500	1.8944	1.8944	7
8	LOAD MANAGEMENT PRICE SIGNAL ($/KWH)	$0.53		$0.63		8
9	TRANSMISSION & DISTRIBUTION ADDER ($/KWH)	$0.09235		$0.09195		9
	SCHEDULE A-RTP SECONDARY					
10	E-19 CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	10
11	E-20 CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	11
12	OPTIONAL SERVICE CHARGE ($/MONTH)	$275.00	$275.00	$275.00	$275.00	12
13	MAXIMUM DEMAND CHARGE ($/KW/MO.)	$4.00	$4.00	$4.15	$4.15	13
14	BASE ENERGY RATE ($/KWH)	$0.00332	$0.00332	$0.00334	$0.00334	14
15	ON-PEAK ENERGY MULTIPLIER	2.1304		2.5818		15
16	PART-PEAK ENERGY MULTIPLIER	2.1304	1.5500	2.5818	1.8944	16
17	OFF-PEAK ENERGY MULTIPLIER	1.5500	1.5500	1.8944	1.8944	17
18	LOAD MANAGEMENT PRICE SIGNAL ($/KWH)	$0.53		$0.63		18
19	TRANSMISSION & DISTRIBUTION ADDER ($/KWH)	$0.09235		$0.09195		19

APPENDIX B
TABLE 9
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED LARGE L&P RATES
E-25

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-25T					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.60		$9.00		3
4	ON-PEAK ENERGY ($/KWH)	$0.12346		$0.13242		4
5	PART-PEAK ENERGY ($/KWH)	$0.07220	$0.06173	$0.07744	$0.06621	5
6	OFF-PEAK ENERGY ($/KWH)	$0.05512	$0.05347	$0.05912	$0.05735	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.62907		$0.66285		7
	SCHEDULE E-25P					
8	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$10.50		$10.90		10
11	ON-PEAK ENERGY ($/KWH)	$0.12558		$0.12504		11
12	PART-PEAK ENERGY ($/KWH)	$0.07344	$0.06279	$0.07313	$0.06252	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05606	$0.05439	$0.05583	$0.05416	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.15379		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.85889		$0.90501		15
	SCHEDULE E-25S					
16	CUSTOMER CHARGE ($/MONTH)	$260.00	$260.00	$260.00	$260.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$11.20		$11.60		18
19	ON-PEAK ENERGY ($/KWH)	$0.13907		$0.13088		19
20	PART-PEAK ENERGY ($/KWH)	$0.08133	$0.06953	$0.07654	$0.06544	20
21	OFF-PEAK ENERGY ($/KWH)	$0.06208	$0.06023	$0.05843	$0.05669	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.12663		$0.15379		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.86394		$0.91033		23

APPENDIX B
TABLE 10
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED LARGE L&P RATES
E-26

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE E-26T					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.60	$0.60	$0.60	$0.60	3
4	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$5.13		$4.77		4
5	ON-PEAK ENERGY ($/KWH)	$0.08202		$0.08336		5
6	PART-PEAK ENERGY ($/KWH)	$0.05566	$0.04758	$0.05657	$0.04836	6
7	OFF-PEAK ENERGY ($/KWH)	$0.04249	$0.04121	$0.04318	$0.04188	7
8	EXCESS DEMAND CHARGE / KWH	$4.90970	$4.90970	$4.90970	$4.90970	8
	SCHEDULE E-26P					
9	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	9
10	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	10
11	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.10	$3.10	$3.25	$3.25	11
12	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.27		$7.86		12
13	ON-PEAK ENERGY ($/KWH)	$0.09498		$0.09744		13
14	PART-PEAK ENERGY ($/KWH)	$0.06447	$0.05512	$0.06614	$0.05655	14
15	OFF-PEAK ENERGY ($/KWH)	$0.04922	$0.04775	$0.05050	$0.04898	15
16	EXCESS DEMAND CHARGE / KWH	$6.27077	$6.27077	$6.27077	$6.27077	16
	SCHEDULE E-26S					
17	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	17
18	CURTAILABLE METER CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	18
19	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$4.00	$4.00	$4.15	$4.15	19
20	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.63		$7.18		20
21	ON-PEAK ENERGY ($/KWH)	$0.10471		$0.10759		21
22	PART-PEAK ENERGY ($/KWH)	$0.07108	$0.06077	$0.07303	$0.06244	22
23	OFF-PEAK ENERGY ($/KWH)	$0.05425	$0.05264	$0.05575	$0.05409	23
24	EXCESS DEMAND CHARGE / KWH	$6.27077	$6.27077	$6.27077	$6.27077	24

A.91-03-004 ALJ/TRP
CACD/lk/3*

APPENDIX B
TABLE 11
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED STANDBY RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE S – TRANSMISSION					
1	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$0.60	$0.60	$0.60	$0.60	1
2	ON-PEAK RATE LIMITER ($/KWH)	$0.62907		$0.65109		2
	SCHEDULE S – PRIMARY					
3	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$3.10	$3.10	$3.25	$3.25	3
4	ON-PEAK RATE LIMITER ($/KWH)	$0.85889		$0.88895		4
	SCHEDULE S – SECONDARY					
5	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$4.00	$4.00	$4.15	$4.15	5
6	ON-PEAK RATE LIMITER ($/KWH)	$0.86394		$0.89418		6
	REDUCED CUSTOMER CHARGE ($/MONTH)					
7	A-1 / A-6	$3.20	$3.20	$3.20	$3.20	7
8	A-10 / A-11	$27.00	$27.00	$27.00	$27.00	8
9	E-19 TRANSMISSION / E-20 TRANSMISSION	$426.00	$426.00	$426.00	$426.00	9

A.91-03-004 ALJ/TRP
CACD/lk/3*

APPENDIX B
TABLE 12
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE AG-1A					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	CONNECTED LOAD CHARGE ($/KW/MONTH)	$2.10	$2.10	$2.15	$2.15	2
3	ENERGY CHARGE ($/KWH)	$0.13690	$0.13690	$0.14035	$0.14035	3
4	RATE LIMITER	N/A	N/A	N/A	N/A	4
	SCHEDULE AG-RA					
5	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	5
6	METER CHARGE ($/MONTH)	$6.20	$6.20	$6.20	$6.20	6
7	CONNECTED LOAD CHARGE ($/KW/MONTH)	$2.10	$2.10	$2.15	$2.15	7
8	ON-PEAK ENERGY ($/KWH)	$0.32849		$0.33665		8
9	PART-PEAK ENERGY ($/KWH)		$0.06882		$0.07053	9
10	OFF-PEAK ENERGY ($/KWH)	$0.07661	$0.05473	$0.07851	$0.05609	10
11	RATE LIMITER ($/KWH)	N/A	N/A	N/A	N/A	11
	SCHEDULE AG-VA					
12	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	12
13	METER CHARGE ($/MONTH)	$6.20	$6.20	$6.20	$6.20	13
14	CONNECTED LOAD CHARGE ($/KW/MONTH)	$2.10	$2.10	$2.15	$2.15	14
15	ON-PEAK ENERGY ($/KWH)	$0.32273		$0.33063		15
16	PART-PEAK ENERGY ($/KWH)		$0.06762		$0.06927	16
17	OFF-PEAK ENERGY ($/KWH)	$0.07359	$0.05377	$0.07539	$0.05509	17
18	RATE LIMITER ($/KWH)	N/A	N/A	N/A	N/A	18
	SCHEDULE AG-4A					
19	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	19
20	METER CHARGE ($/MONTH)	$6.20	$6.20	$6.20	$6.20	20
21	CONNECTED LOAD CHARGE ($/KW/MONTH)	$2.10	$2.10	$2.15	$2.15	21
22	ON-PEAK ENERGY ($/KWH)	$0.32029		$0.32821		22
23	PART-PEAK ENERGY ($/KWH)		$0.06710		$0.06876	23
24	OFF-PEAK ENERGY ($/KWH)	$0.06442	$0.05336	$0.06601	$0.05468	24
25	RATE LIMITER ($/KWH)	N/A	N/A	N/A	N/A	25

APPENDIX B
TABLE 13
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE AG-5A					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$6.20	$6.20	$6.20	$6.20	2
3	CONNECTED LOAD CHARGE ($/KW/MONTH)	$5.10	$5.10	$5.15	$5.15	3
4	ON-PEAK ENERGY ($/KWH)	$0.22772		$0.23441		4
5	PART-PEAK ENERGY ($/KWH)		$0.04771		$0.04911	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04685	$0.03794	$0.04823	$0.03906	6
7	RATE LIMITER ($/KWH)	N/A	N/A	N/A	N/A	7
8	MINIMUM BILL ($/KW-YEAR)	$0.00		$0.00		8
	SCHEDULE AG-6A					
9	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	9
10	CONNECTED LOAD CHARGE ($/KW/MONTH)	$5.10	$5.10	$5.15	$5.15	10
11	ENERGY CHARGE ($/KWH)	$0.07973	$0.04170	$0.08215	$0.04276	11
12	RATE LIMITER ($/KWH)	N/A	N/A	N/A	N/A	12
	SCHEDULE AG-1B					
13	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	13
	MAXIMUM DEMAND CHARGE					
14	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.60	$1.80	14
15	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH)	$0.40	$0.25	$0.40	$0.30	15
16	ENERGY CHARGE ($/KWH)	$0.11883	$0.11883	$0.12155	$0.12155	16
17	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	17
	SCHEDULE AG-RB					
18	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	18
19	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	19
20	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.60		20
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
21	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.60	$1.80	21
22	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH)	$0.40	$0.25	$0.40	$0.30	22
23	ON-PEAK ENERGY ($/KWH)	$0.28380		$0.29134		23
24	PART-PEAK ENERGY ($/KWH)		$0.07732		$0.07914	24
25	OFF-PEAK ENERGY ($/KWH)	$0.08347	$0.06149	$0.08544	$0.06294	25
26	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	26

APPENDIX B
TABLE 14
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE AG-V8					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.60		3
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
4	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.60	$1.80	4
5	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH)	$0.40	$0.25	$0.40	$0.30	5
6	ON-PEAK ENERGY ($/KWH)	$0.25229		$0.25887		6
7	PART-PEAK ENERGY ($/KWH)		$0.07501		$0.07676	7
8	OFF-PEAK ENERGY ($/KWH)	$0.07649	$0.05964	$0.08032	$0.06103	8
9	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	9
	SCHEDULE AG-4B					
10	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	10
11	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	11
12	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.60		12
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
13	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.60	$1.80	13
14	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH)	$0.40	$0.25	$0.40	$0.30	14
15	ON-PEAK ENERGY ($/KWH)	$0.21011		$0.21464		15
16	PART-PEAK ENERGY ($/KWH)		$0.06917		$0.07069	16
17	OFF-PEAK ENERGY ($/KWH)	$0.06572	$0.05499	$0.06735	$0.05636	17
18	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	18
	SCHEDULE AG-4C					
19	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	19
20	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	20
21	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.55		$2.60		21
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
22	SECONDARY VOLTAGE ($/KW/MONTH)	$2.55	$1.75	$2.60	$1.80	22
23	PRIMARY VOLTAGE DISCOUNT ($/KW/MONTH)	$0.40	$0.25	$0.40	$0.30	23
24	ON-PEAK ENERGY ($/KWH)	$0.21011		$0.21464		24
25	PART-PEAK ENERGY ($/KWH)	$0.09451	$0.06917	$0.09656	$0.07069	25
26	OFF-PEAK ENERGY ($/KWH)	$0.06123	$0.05499	$0.06257	$0.05636	26
27	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	27

APPENDIX B
TABLE 15
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE AG-5B					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.50		$2.55		3
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
4	SECONDARY VOLTAGE	$6.00	$4.05	$6.15	$4.15	4
5	PRIMARY VOLTAGE DISCOUNT	$0.85	$0.60	$0.90	$0.60	5
6	ON-PEAK ENERGY ($/KWH)	$0.13658		$0.13997		6
7	PART-PEAK ENERGY ($/KWH)		$0.04062		$0.04149	7
8	OFF-PEAK ENERGY ($/KWH)	$0.03919	$0.03230	$0.04003	$0.03299	8
9	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	9
10	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		10
	SCHEDULE AG-5C					
11	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	11
12	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	12
13	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.50		$2.55		13
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
14	SECONDARY VOLTAGE	$6.00	$4.05	$6.15	$4.15	14
15	PRIMARY VOLTAGE DISCOUNT	$0.85	$0.60	$0.90	$0.60	15
16	ON-PEAK ENERGY ($/KWH)	$0.13658		$0.13997		16
17	PART-PEAK ENERGY ($/KWH)	$0.05379	$0.04062	$0.05508	$0.04149	17
18	OFF-PEAK ENERGY ($/KWH)	$0.03421	$0.03230	$0.03503	$0.03299	18
19	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	19
20	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		20
	SCHEDULE AG-6B					
21	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	21
	MAXIMUM DEMAND CHARGE ($/KW/MONTH)					
22	SECONDARY VOLTAGE	$6.00	$4.05	$6.15	$4.15	22
23	PRIMARY VOLTAGE DISCOUNT	$0.85	$0.60	$0.90	$0.60	23
24	ENERGY CHARGE ($/KWH)	$0.06709	$0.03563	$0.06836	$0.03626	24
25	RATE LIMITER ($/KWH)	$1.12804	$1.12804	$1.15549	$1.15549	25

APPENDIX B
TABLE 16
PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED STREETLIGHTING RATES

LINE NO.		05/01/91 RATES SUMMER	05/01/91 RATES WINTER	01/01/92 RATES SUMMER	01/01/92 RATES WINTER	LINE NO.
	SCHEDULE LS-1					
1	ENERGY CHARGE ($/KWH)	$0.07616	$0.07616	$0.07290	$0.07290	1
	SCHEDULE LS-2					
2	ENERGY CHARGE ($/KWH)	$0.07616	$0.07616	$0.07290	$0.07290	2
	SCHEDULE LS-3					
3	SERVICE CHARGE ($/METER/MO.)	$3.00	$3.00	$3.00	$3.00	3
4	SWITCHING CHARGE ($/CIRCUIT)	$3.25	$3.25	$3.25	$3.25	4
5	ENERGY CHARGE ($/KWH)	$0.07616	$0.07616	$0.07290	$0.07290	5
	SCHEDULE OL-1					
6	ENERGY CHARGE ($/KWH)	$0.07633	$0.07633	$0.07317	$0.07317	6

92RATES
91ECAC A.91-04-003

APPENDIX B

Table 17

PACIFIC GAS AND ELECTRIC COMPANY
RATES FOR SCHEDULES LS-1, LS-2 AND OL-1
FACILITY RATES EFFECTIVE 1-01-92
91 ECAC DECISION ENERGY RATES
EFFECTIVE 1-01-92

--NOMINAL LAMP RATINGS--			ALL NIGHT RATES PER LAMP PER MONTH													HALF-HOUR ADJ.	
			SCHEDULE LS-2			SCHEDULE LS-1											
LAMP WATTS	KWHR PER MONTH	AVERAGE INITIAL LUMENS	A	B	C	A	B	C	D	D.1	E	E.1	F	F.1	OL-1	LS-1 & LS-2	OL-1
MERCURY VAPOR LAMPS																	
100	40	3,500	3.067	3.963	4.467	9.567	--	7.464	--	--	--	--	--	--	--	.133	--
175	68	7,500	5.108	5.947	6.451	11.050	7.992	9.578	--	--	13.442	13.442	10.690	17.092	11.068	.225	.226
250	97	11,000	7.222	8.146	8.650	14.241	10.460	--	--	--	--	--	--	--	--	.321	--
400	152	21,000	11.232	12.127	12.632	18.416	14.472	--	--	--	--	--	--	--	18.457	.504	.506
700	266	37,000	19.542	20.804	21.309	27.303	23.373	--	--	--	--	--	--	--	--	.881	--
1,000	377	57,000	27.634	28.812	29.316	--	--	--	--	--	--	--	--	--	--	1.249	--
INCANDESCENT LAMPS																	
58	20	600	--	--	--	10.049	--	--	--	--	--	--	--	--	--	.066	--
92	31	1,000	2.411	5.008	5.512	10.851	--	--	--	--	--	--	--	--	--	.103	--
189	65	2,500	4.889	7.671	8.175	13.531	9.837	--	--	--	--	--	--	--	--	.215	--
295	101	4,000	7.514	10.364	10.869	16.230	12.537	--	--	--	--	--	--	--	--	.335	--
405	139	6,000	10.284	13.505	14.009	19.404	--	--	--	--	--	--	--	--	--	.461	--
620	212	10,000	15.606	18.787	19.291	--	--	--	--	--	--	--	--	--	--	.702	--
860	294	15,000	21.584	25.118	--	--	--	--	--	--	--	--	--	--	--	.974	--
LOW PRESSURE SODIUM VAPOR LAMPS																	
35	21	4,800	1.682	--	--	--	--	--	--	--	--	--	--	--	--	.070	--
55	29	8,000	2.265	--	--	--	--	--	--	--	--	--	--	--	--	.096	--
90	45	13,500	3.431	--	--	--	--	--	--	--	--	--	--	--	--	.149	--
135	62	21,500	4.671	--	--	--	--	--	--	--	--	--	--	--	--	.205	--
100	78	33,000	5.837	--	--	--	--	--	--	--	--	--	--	--	--	.258	--
HIGH PRESSURE SODIUM VAPOR LAMPS																	
AT 120 VOLTS																	
70	29	5,800	2.265	3.302	3.806	7.962	--	6.450	10.070	10.070	10.112	10.112	14.030	13.237	7.970	.096	.096
100	41	9,500	3.140	4.204	4.709	8.850	--	7.412	11.031	11.031	11.032	11.032	15.064	14.319	8.861	.136	.136
150	60	16,000	4.525	5.589	6.094	10.686	--	8.881	12.334	12.334	12.452	12.452	16.838	16.027	--	.199	--
AT 240 VOLTS																	
70	34	5,800	2.630	3.666	4.170	--	--	--	--	--	--	--	--	--	--	.113	--
100	47	9,500	3.577	4.642	5.146	--	--	--	--	--	--	--	--	--	--	.156	--
150	69	16,000	5.181	6.246	6.750	--	--	--	--	--	--	--	--	--	--	.229	--
200	81	22,000	6.056	7.120	7.625	13.655	--	11.063	--	--	14.650	14.650	20.055	18.822	13.677	.268	.269
250	100	27,000	7.441	8.505	9.010	14.795	--	12.643	--	--	16.333	16.333	21.838	20.806		.331	--
310	119	37,000	8.826	--	--	--	--	--	--	--	--	--	--	--	--	.394	--
400	154	46,000	11.378	12.442	12.946	19.766	--	16.833	--	--	20.568	20.568	26.373	25.161	--	.510	--
METAL HALIDE LAMPS																	
400	162	30,000	11.961	--	--	--	--	--	--	--	--	--	--	--	--	.537	--
1,000	387	90,000	28.363	--	--	--	--	--	--	--	--	--	--	--	--	1.282	--

Energy Rate @ .07290 per kwh LS-1 & LS-2
.07317 per kwh OL-1

12/13/1991

A.91-04-003

APPENDIX C

Pacific Gas and Electric Company
1991 ECAC -- September 1991 Hearings

Comparison of Parties' Proposals For Revenue Allocation Caps

Revenue Allocation Proposals

A		B	C	D	E	F	G	H	I	J	K	L	M	N
		Present Revenue at 5/1/91 Rates	Full EPMC Proposed Revenue	Percent Change on Present	SAPC Proposed Revenue	Percent Change on Present	AECA/CFBF Proposed Revenue 0% Ag Cap	Percent Change on Present	PGAE/DRA Proposed Revenue 5% Ag Cap	Percent Change on Present	CLECA Proposed Revenue 7% Ag Cap	Percent Change on Present	FEA Proposed Revenue 10% Ag Cap	Percent Change on Present
Line														
1	Residential	$2,788,215	$2,781,065	-0.26%	$2,867,342	2.84%	$2,843,589	1.99%	$2,835,777	1.71%	$2,832,632	1.59%	$2,827,897	1.42%
2	Agricultural	$390,127	$554,908	42.26%	$401,084	2.81%	$401,088	2.81%	$420,430	7.77%	$428,168	9.75%	$439,790	12.73%
3	Streetlighting	$43,458	$42,704	-1.74%	$44,170	1.64%	$42,704	-1.74%	$42,704	-1.74%	$42,704	-1.74%	$42,704	-1.74%
4	Small L&P	$976,439	$1,020,838	4.55%	$1,003,915	2.81%	$1,043,523	6.87%	$1,040,664	6.58%	$1,039,524	6.46%	$1,038,021	6.31%
5	Medium L&P	$1,427,048	$1,417,304	-0.68%	$1,467,591	2.84%	$1,466,676	2.78%	$1,462,624	2.49%	$1,443,224	1.13%	$1,441,161	0.99%
6	E-19	$449,671	$447,065	-0.58%	$462,234	2.79%	$439,124	-2.35%	$437,950	-2.61%	$455,269	1.24%	$454,590	1.09%
7	E-20 Tariff	$1,165,280	$1,178,140	1.10%	$1,196,798	2.62%	$1,206,431	3.44%	$1,201,965	3.15%	$1,200,614	3.03%	$1,197,971	2.80%
8	E-20 Contracts	$84,108	$82,220	-2.24%	$82,220	-2.24%	$82,220	-2.24%	$82,220	-2.24%	$82,220	-2.24%	$82,220	-2.24%
9	E-20 Total	$1,249,398	$1,260,360	0.88%	$1,278,019	2.29%	$1,287,651	3.06%	$1,284,206	2.79%	~~$1,287,664~~ $1,282,834	~~3.06%~~ 2.68%	$1,280,192	2.46%
10	Total System	$7,324,355	$7,524,354	2.73%	$7,524,354	2.73%	$7,524,355	2.73%	$7,524,354	2.73%	$7,524,355	2.73%	$7,524,354	2.73%

Notes:

Total system revenues differ slightly due to rounding.

Revenues shown include allocated and nonallocated revenues. Agricultural revenues do not exactly equal SAPC plus the cap due to nonallocated revenues.

APPENDIX D
Page 1

List of Appearances

Applicant: Michelle L. Wilson and Robert Mc Lennan, Attorneys at Law, for Pacific Gas and Electric Company.

Interested Parties: C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Barkovich and Yap, by Barbara Barkovich, for Barkovich and Yap; Patrick J. Bittner and Caryn Hough, Attorneys at Law, for California Energy Commission; Morrison & Foerster, by Jerry Bloom and Lynn Haug, Attorneys at Law, and Morse, Richard, Weisenmiller & Associates, by Mark Younger, for California Cogeneration Council; Jackson, Tufts, Cole & Black, by William H. Booth and Joseph S. Faber, Attorneys at Law, for California Large Energy Consumers Association; Henwood Energy Services, by David Branchcomb, for Independent Energy Producers Association; Maurice Brubaker, for Drazen Brubaker & Associates; Mc Craken, Byers & Martin, by David J. Byers, Attorney at Law, for Peninsula Street Light Authority and City of Fresno; Ralph Cavanagh, Attorney at Law, for Natural Resources Defense Council; Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for California Manufacturers Association; Sam De Frawi, for Naval Facilities Engineering Comman; Phil Di Virgilio, for Destec Energy, Inc.; Karen Edson, for KKE & Associates; Norman Furuta, Attorney at Law, for Federal Executive Agencies; Steven A. Geringer, Attorney at Law, for California Farm Bureau Federation; Grueneich, Ellison & Schneider, by Dian M. Grueneich, Attorney at Law, for California Department of General Services; Steve Harris, for Transwestern Pipeline Company; Fulbright & Jaworsky, by Pat Keeley, Attorney at Law, and Recon Research Corporation, by Dr. Andrew Safir, for Canadian Petroleum Association; Roberts & Kerner, by Douglas K. Kerner, Attorney at Law, for Geothermal Resources Association; Joseph G. Meyer, for Joseph Meyer Associates; Melissa Metzler, for Barakat & Chamberlin; Steven Moss, for Spectrum Economics, Inc.; Anderson, Donovan & Poole, by Edward G. Poole, Attorney at Law, for various clients; John D. Quinley, for Cogeneration Service Bureau; Bruce A. Reed, Janet K. Lohmann, and David R. Hinman, Attorneys at Law; for Southern California Edison Company; C. B. Rooney and David J. Gilmore, Attorneys at Law, for Southern California Gas Company; Donald Salow, for Association of California Water Agencies; Bartle Wells Associates, by Reed V. Schmidt, for California City-County Street Light Association; Michel P. Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Downey, Brand, Seymour & Rohwer, by Phil Stohr and Ron Liebert,

APPENDIX D
Page 2

Attorneys at Law, for Industrial Users; Randolph L. Wu and Phillip D. Endom, Attorneys at Law, for El Paso Natural Gas Company; Larry Golberg, for Sequoia Technical Services; Carolyn Kehrein, for Procter & Gamble Manufacturing Company; Sara Steck Myers, Attorney at Law, for Coalition for Energy Efficiency and Renewable Technologies; Thomas A. Tribble, P.E, J.D., for Regents - University of California; Messrs. Ater, Wynne, Hewitt, Dodson & Skerritt, by Mark Trinchero, Attorney at Law for Cogenerators of Southern California; and William B. Marcus, for JBS Energy, Inc.

State Service: Messrs. Greve, Clifford, Diepenbrock & Paras, by Matthew V. Brady, for California Department of General Services.

Commission Advisory and Compliance Division: Martha J. Sullivan.

Division of Ratepayer Advocates: James E. Scarff and Robert Cagen, Attorneys at Law, and Jeff Meloche.

Division of Strategic Planning: Jeffrey Dasovich.

(END OF APPENDIX D)