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Decision 90-12-066 December 19, 1990

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, 1990; and for Commission Order Finding that PG&E's Gas and Electric Operations during the Reasonableness Review Period from January 1, 1989, to December 31, 1989, were Prudent. (U 39 M)	Application 90-04-003 (Filed April 2, 1990)

(See Decision 90-10-062 for appearances.)

Additional Appearance

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OPINION ON REVENUE ALLOCATION

I. Summary of Decision

By this decision we adopt for Pacific Gas and Electric Company (PG&E) the revenue allocation criteria used in establishing revised electric rates which become effective January 1, 1991. The criteria are then applied in setting rates which implement the revenue increase adopted by Decision (D.) 90-10-062 in an earlier phase of this proceeding, as well as consolidated revenue adjustments resulting from several other proceedings: (1) PG&E's 1991 Attrition Rate Adjustment filing (Advice Letter 1319-E); (2) PG&E's 1991 Cost of Capital proceeding (Application (A.) 90-05-011); (3) PG&E's Customer Energy Efficiency proceeding (A.90-04-041; (4) PG&E's Earthquake Recovery Account proceeding (A.90-05-003); (5) PG&E's Environmental Compliance proceeding (A.89-05-001); and (6) PG&E's Demand-Side Management/Research and Development offset (Resolutions E-3174 and E-3188).

We continue to move toward a system of revenue allocation for PG&E's electric customers which establishes cost-based rates using the equal percentage of marginal cost (EPMC) method, while we avoid the severe rate shock which would occur if agricultural customers were moved abruptly to full EPMC. Movement to fully cost-based rates would require that the rates for that class be increased by an average of 58.25%. By adopting a cap on increases which is set at the system average percentage change (SAPC) plus 3.5%, we raise agricultural rates by an average of 13.94%.

Based on the adopted total revenue requirement increase of $688.3 million for the consolidated revenue changes, the adopted criteria affect the various rate classes as follows:

Customer Class	Adopted Revenue (1,000's)	Increase Percent
Residential	$296,280	11.79%
Agricultural	46,885	13.94%
Streetlighting	630	1.73%
Small Light & Power	123,817	14.10%
Medium Light & Power	73,143	5.82%
E-19	44,262	12.67%
E-20	103,261	10.07%
Contracts	0	0.00%
Total System Increase	$688,278	10.59%

II. Background

By D.90-10-062 issued in an earlier phase of this proceeding (PG&E's Energy Cost Adjustment Clause (ECAC), Annual Energy Rate mechanism (AER), Electric Revenue Adjustment Mechanism (ERAM), and Low Income Rate Assistance (LIRA) proceeding), we adopted forecasts of PG&E's resource mix, energy prices, and the related payment factors for power purchases from variably priced qualifying facilities for the 12- month period beginning November 1, 1990. We also adopted the ECAC, AER, ERAM, and LIRA revenue requirements adjustments associated with those forecasts. The net revenue change authorized by that decision is an increase of $480,912,000 effective November 1, 1990. We authorized PG&E to defer implementation of rate changes associated with that increase until January 1, 1991 so that a single set of rate changes consolidating the $480,912,000 increase with adjustments from several other proceedings could be implemented concurrently. This opinion will decide revenue allocation criteria to be used in setting rates which will allow PG&E to recover the consolidated revenue requirement change.

At the time of the hearings the total amount of the revenue increase to be implemented on January 1, 1991 could not determined, since several of the proceedings to be consolidated for rate implementation purposes were pending. These included the Attrition Rate Adjustment, Cost of Capital, and Earthquake Recovery Account proceedings noted earlier. Based on the amounts requested and the recommendations of other parties in those proceedings, PG&E submitted Exhibit 40, in which it projected a range for the total increase of $646 million to $756 million. PG&E considers this range to be sufficiently narrow for revenue allocation purposes. PG&E proposed to use an increase of $700 million, or 10.77%, for the purpose of developing revenue allocation criteria. Each of the parties submitting revenue allocation testimony used the $700 million figure. Appendix A shows the development of the final, consolidated revenue requirement increase of $688.3 million which is based on the amounts that have been adopted in the various proceedings.

In recent years, we have pursued a goal of developing cost-based rates. When rates are fully based on costs, customers pay rates that are proportionate to the costs the utility incurs in serving them. In determining a customer group's cost responsibility, we rely on the marginal costs of various components of service. The emphasis on marginal costs is consistent with microeconomic theory which holds that when buyers pay prices equal to the marginal costs of supplying a good or service, productive efficiency and total welfare are maximized. Revenue allocation is an important step in the translation of marginal costs into rates.

As we stated in PG&E's last general rate case (GRC), revenue allocations based on the marginal costs and the guidelines adopted in the GRC should take place whenever there is a substantial change in revenue requirements, and it is logical that such revenue allocations will be addressed in ECAC proceedings. (D.89-12-057, p. 240a.) Typically, greater revenue adjustments are encountered in ECAC proceedings than in GRCs. On the other hand, when we adopted a generic plan for processing GRCs and ECACs in D.89-01-040, we determined that rate design issues are more appropriately addressed in GRCs and the newly established annual "rate design window" phase of GRCs rather than in ECAC proceedings.

Hearings on revenue allocation were held on September 24 and 25, 1990 in San Francisco, California. The active parties in this phase were PG&E, the Commission's Division of Ratepayer Advocates (DRA), Toward Utility Rate Normalization (TURN), the California Farm Bureau Federation and Western Growers Association (collectively, CFBF), California Large Energy Consumers Association (CLECA), California Manufacturers Association (CMA), California City-County Street Light Association (CAL-SLA), and Industrial Users (Industrial Users). This phase was submitted with the receipt of reply briefs on October 12, 1990.

Comments on the proposed decision of the Administrative Law Judge (ALJ) were filed by PG&E and TURN. Reply comments were filed by PG&E. We have carefully considered these filings in arriving at our decision.

III. Marginal Costs

Marginal costs are the changes in total costs resulting from an incremental change in a specified element of the utility's operation. We consider three general types of marginal costs for electric utilities. Marginal capacity costs measure the costs that change with changes in kilowatts of peak demand. Marginal customer costs are the costs of providing access to the utility's system, meter reading, and billing that change as the number of customers changes. Marginal energy costs vary with changes in kWh of energy.

In PG&E's last GRC we adopted marginal capacity and marginal customer costs, and provided for their use in subsequent allocations. Marginal energy costs are updated in each ECAC proceeding to incorporate the adopted resource assumptions. Appendix C contains the previously-adopted marginal costs which are carried forward from the GRC as well as the marginal energy costs and an adjustment to the marginal generating capacity cost, discussed below.

A. Marginal Energy Costs

PG&E presented marginal energy costs based on the resource assumptions underlying the joint recommendation of parties which was submitted in the resource and revenue requirement phase of this proceeding. In developing the marginal costs, PG&E used ratios for the various time-of-use periods which were derived through application of the zero-intercept method in the last GRC. PG&E notes that the ECAC schedule does not permit the number of production simulation model runs necessary to apply the zero-intercept method and obtain updated ratios.

One of the primary components of marginal energy costs is the forecasted cost of natural gas. Consistent with the procedure adopted in the GRC, PG&E used the average utility electric generation (UEG) cost of gas exclusive of customer costs.

PG&E's proposed marginal energy costs were uncontested, and were used by other parties in developing their revenue allocation proposals. We agree that PG&E's methodology is consistent with that used and adopted in the last GRC and is appropriate for an ECAC proceeding.

B. Energy Reliability Index

As previously noted, the marginal capacity costs adopted in the GRC are used in performing subsequent revenue allocations. (D.89-12-057, p. 240a.) However, the marginal generation capacity cost of $56.17/kW-yr adopted in that decision was multiplied by a six-year average Energy Reliability Index (ERI) factor.[1] We indicated that the ERI factor would be updated whenever revenue allocation occurs:

> "The values for the six years of ERIs for this proceeding should be derived from the long-term resource plan. The average of the ERIs for the six years beginning with the test year is 0.418. In future proceedings, the most recently adopted series of ERIs should be used to calculate the average ERI used in revenue allocation and rate design. The [Biennial Resources Plan Update (BRPU)] proceeding will likely be the primary source of future series of ERI projections." (D.89-12-057, p. 201.)

An issue arose in this proceeding over the proper method to be used in updating the six-year average ERI.

1. <u>The Parties' Positions</u>

PG&E used the same series of ERIs that was adopted in the 1990 GRC. The average ERI of 0.418 adopted in the GRC was based on the six years 1990 through 1995 inclusive. For this year's ECAC, PG&E updated the six-year average by deleting the 1990 value of 0.400 and adding the 1996 value 0.716 from the same reliability model run, yielding a proposed ERI of 0.471. PG&E argues that no other series of ERIs based on a long-term resource plan has been

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1 An ERI of less than 1.0 signals that the utility has more than the needed capacity to meet its target reserve margin, and that resources other than the combustion turbine may be the sources of marginal generation capacity. The existence of lower-priced sources of marginal generation capacity for utilities with adequate capacity makes it logical to derive marginal costs from those sources. Using the ERI adjustment reflects the expected availability of lower-priced sources of marginal generation capacity.

The ERI is derived from the utility's resource plan and reflects the relation of forecasted reserve margin to target reserve margin.

adopted by the Commission, and that its proposal is therefore the correct one under the GRC guidelines.

DRA believes that more recent ERI numbers taken from PG&E's April 1990 Phase 1B compliance filing in the BRPU (filed pursuant to D.90-03-060 in I.89-07-004) will provide a more meaningful value. DRA proposes using values from this series for the years 1992 through 1996 and, for 1991, the ERI of 1.0 adopted in the joint recommendation of parties in the earlier phase of this proceeding. Acknowledging the GRC decision's provision for using the most recently adopted series of ERIs, DRA suggests that the Commission should decide whether strict adherence to that language is desirable here. DRA's proposal results in a six-year average ERI of 0.754.

CLECA adopted the same approach as DRA, and arrived at the same recommendation for an average ERI of 0.754. CLECA states that while PG&E's recent filing in the BRPU case has not been "officially" adopted by the Commission, it was prepared pursuant to specific Commission instructions set forth in D.90-03-060.

Industrial Users support the DRA/CLECA recommendation for an ERI of 0.754, based on the belief that the ERI numbers favored by DRA and CLECA are the best available evidence at the present time and that they will be adopted in the BRPU proceeding.

In addition to disagreeing with the proposal to use the ERIs from its BRPU filing, PG&E criticizes the use by DRA, CLECA, and Industrial Users of an ERI of 1.0 for the 1991 value in the six-year average ERI. This is the value that was proposed in the joint recommendation and adopted by D.90-10-062. PG&E notes that this value was proposed for adjusting as-delivered capacity payments to qualifying facilities in the 1990-91 ECAC forecast period, which is a short-term resource plan. PG&E believes this violates the GRC plan to use the adopted ERI series from the long-term resource plan.

2. **Discussion**

PG&E updated its six-year average ERI factor from that adopted in the GRC by deleting the 1990 value and adding the 1996 value. However, it used the same ERI series for the update. DRA, CLECA, and Industrial Users argue that this series is outdated.

We agree that the long-term resource plan data adopted in PG&E's last GRC are somewhat dated, but we are reluctant to utilize the data series filed by PG&E in its Phase 1B BRPU filing instead. Despite the characterization of PG&E's filing as a compliance filing made pursuant to specific directives in D.90-03-060, the fact remains that those ERIs have not been adopted by the Commission.

As noted by PG&E in its reply brief, adoption of ERI values proposed in another proceeding which is pending could have the effect of prejudging the outcome of that proceeding. Adopting an ERI factor which is too high could result in ratepayers paying more for peak capacity than is justified by system circumstances. We are not persuaded that filed but yet-to-be-adopted ERI values constitute a sufficient basis for raising peak capacity costs in this proceeding. For this ECAC, we will adopt PG&E's proposal to use values adopted in the GRC. We anticipate that for future revenue allocations, we will be able to follow the plan we envisioned in the GRC to use recently-adopted BRPU values. However, if decision timing problems persist, it may be necessary to adjust that plan.

The other ERI issue is whether to use a value of 1.0 for the 1991 value in the six-year average. That value was adopted by the parties (including PG&E) to the joint recommendation in the first phase of this proceeding. We believe the parties making this proposal have not given adequate weight to our directive in the GRC decision that "[i]n future proceedings, the most recently adopted <u>series</u> of ERIs should be used in revenue allocation..." (D.89-12-057, p. 201; emphasis supplied.) We provided for a series to be derived from the utility's long-term resource plan, and anticipated a single proceeding involving that plan, most likely the most recent BRPU proceeding.) We did not anticipate that a single year's value, derived in the ECAC proceeding for the purpose of adjusting capacity payments to qualifying facilities, would be combined with a five-year series of values derived from the proceeding which addresses long-term planning issues.

We conclude that for 1991, PG&E's six-year average ERI factor of 0.471 should be adopted for revenue allocation purposes.

IV. Interclass Revenue Allocation

After marginal costs are developed, they are used to allocate the utility's revenue requirement to the customer classes, and then to the various schedules within each class, according to the costs that the class or schedule imposes on the system. In recent years we have repeatedly stated our intent to allocate revenue among the customer classes based on an equal percentage of marginal cost (EPMC). 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 must be adjusted to equal the revenue requirement for the system. 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.

Page 1 of Appendix B shows that for the consolidated 1991 PG&E revenue requirement increase, the marginal costs adopted in the previous section combined with a $688.3 million system increase yield a revenue allocation which would result in the following increases if each class were moved to its full EPMC allocation:

Customer Class	EPMC Revenue Allocation Class Revenue Increases (1,000's)	Percent
Residential	$225,253	8.97%
Agricultural	195,860	58.25%
Streetlighting	630	1.73%
Small Light & Power	118,091	13.45%
Medium Light & Power	39,937	3.18%
E-19	34,419	9.85%
E-20	74,087	7.23%
Contracts	0	0.00%
Total System Increase	$688,278	10.59%

The foregoing table shows that in this case, as in other recent revenue allocations, movement to full EPMC would result in a very substantial increase for the agricultural class. The increase of 58.25% is far greater than the increases required to bring other classes to full EPMC. We have previously stated our concerns about such large increases. Thus, although we have stated our intent to move toward an allocation based on EPMC, we have also moderated our progress toward EPMC to avoid disruptive rate effects of that magnitude.

In this case, all parties endorse in principle the EPMC approach, with some limits to moderate the rate effects on particular classes. They differ, however, on the levels of appropriate caps and floors, particularly for the agricultural class. Our discussion of interclass allocation will accordingly focus on the parties' reasons for advocating their favored levels of caps and floors. We first address an issue that arose in the calculation of the system average percentage change (SAPC) which is used as a reference point for defining caps and floors. We then discuss the various proposals for caps and floors. Finally, we address the appropriate adjustment for the streetlighting class, which was accorded separate treatment in the GRC.

A. **System Average Percentage Change**

Our decisions in I.86-10-001 have permitted utilities to enter into special negotiated rate contracts with customers who have the ability to bypass the utility's system. In last year's GRC we adopted an approach to revenue allocation which excludes all sales and revenues associated with special contracts from the revenue allocation process. (D.89-12-057, p. 245.)

For this proceeding, parties disagree on whether, for capping purposes, the revenues from special contracts should be excluded from the calculation of the SAPC.

1. **The Parties' Positions**

PG&E proposes the inclusion of special contract revenues in calculating the SAPC around which caps and floors are determined. PG&E notes that this is consistent with the manner in which the Commission Advisory and Compliance Division implemented the GRC last year. PG&E also believes that such inclusion best accomplishes the Commission's intent to maintain interclass relationships as if the need for special contracts had not arisen.

CLECA believes that the determination of the SAPC which is used to define caps and floors is part of the revenue allocation process. Since the Commission has excluded the sales, marginal costs, and revenues associated with special contracts from the revenue allocation process, CLECA believes it is clear that the Commission intended to exclude the revenues from the calculation of the SAPC for capping purposes. DRA concurs with CLECA, noting further that in Finding of Fact 219 of D.89-12-057 the Commission found that removing all special contract sales and revenues from the revenue allocation process leaves the relationships among the other classes unchanged.

2. **Discussion**

Because the special contract rates are not increased by the revenue allocation process, PG&E's inclusion of special contract revenues has the effect of lowering the SAPC. Appendix B shows that for an overall system increase of 10.59%, the allocated-revenue SAPC is 10.78% if special contract revenues are included in the calculation of the SAPC and 10.96% if such revenues are excluded. Under most proposals, caps are defined in relation to the allocated-revenue SAPC. Inclusion of special contract revenue in the denominator of the percentage calculation has the effect of lowering the percentage increase applicable to capped classes. This will in turn slow the movement of such classes to full EPMC allocation.

D.89-12-057 did not explicitly state the Commission's intent that special contract revenue be excluded from the SAPC calculation, but we believe that such an intent is reasonably clear from the decision's more general provision for excluding sales and revenues from the revenue allocation process. We reaffirm that intent here. We agree that it would be inconsistent to exclude special contract sales, marginal costs, and revenues from the initial EPMC allocation (as all parties including PG&E agree should be done), then include such revenues for the purpose of defining caps. We find no basis for adopting such an inconsistent approach at this time.

B. Caps and Floors

In PG&E's last GRC we indicated that in subsequent allocations we would use caps and floors of SAPC plus or minus 5% as guidelines in developing a revenue allocation, except for the streetlighting class. However, we also cautioned parties against overrelying on this figure or this formula, and reserved the right to fit the revenue allocation to the particular circumstances faced at the time. (D.89-12-057, p. 241.) We reaffirm both the guideline and the need to fit the caps and floors to current circumstances as we approach the issue for this case.

The predominant issue in this proceeding was the degree to which the agricultural class should be moved towards a full EPMC revenue allocation. An allied issue was the way in which the shortfall in revenues from the agricultural class should be made up by the remaining classes. The parties' proposals are summarized below.

1. <u>The Parties' Positions</u>

a. <u>PG&E</u>

PG&E initially proposed a cap of SAPC plus 2% for agricultural customers, and caps and floors of SAPC plus or minus 5% for the remaining customers (with the exception of streetlighting, which is discussed below). PG&E believes the Commission should continue the 2% cap for agriculture set in the GRC. (D.89-12-057, pp. 240-240a.) The company also believes that the Commission should temper movement of agricultural customers to full EPMC pending completion of a study of agricultural rate issues that was ordered by D.89-12-057 (Ordering Paragraph 52), noting the Commissions's reference to "harsh rate impacts that may not be justified." (Id., p. 240.) Because of the large projected system increase of 10.8%, PG&E revised its allocation proposal by limiting the caps and floors to SAPC plus or minus 2% for all classes except streetlighting.

PG&E asserts that under the higher caps for the agricultural class proposed by other parties, the class would face "severe" increases, ranging from 14.94% to 18.37%, compared to 12.46% under PG&E's proposal. PG&E further asserts that the circumstances which led the Commission to adopt a 2% cap in the GRC have not changed. These include the conversions of customers to time-of-use (TOU) schedules, which are still taking place. Given the impact of such conversions on measurements of class revenue responsibility, and the possibility that the required study could lead the Commission to reconsider the EPMC responsibility of the class, PG&E argues it would be imprudent to move too rapidly to full EPMC at this time.

PG&E opposes proposals of other parties to establish only caps and eliminate floors. PG&E observes that a revenue allocation scheme using caps and floors was adopted in the GRC, and does not believe that the record in this case is sufficiently well developed to provide a basis for eliminating floors.

b. CFBF

CFBF states that it supports the Commission's movement to cost based rates, but in view of the very significant system increase in this case, it recommends an increase for agricultural customers which is limited to the SAPC. Larger increases would assertedly cause rate shock for this class. CFBF notes that in last year's GRC, the Commission adopted a cap of 2% over SAPC in lieu of the guideline cap of 5% when the revenue increase being allocated was $272 million. Since the consolidated increase involved in this proceeding is about $700 million, CFBF believes that a lower cap is appropriate. Alternatively, if the Commission determines that there should be some movement to EPMC for agricultural customers, CFBF "grudgingly" supports PG&E's proposed cap of SAPC plus 2%.

CFBF echoes PG&E's observation that in the GRC decision, the Commission tempered movement of the agricultural class to EPMC in part due to the ongoing conversion of customers within that class to TOU schedules, and that this situation persists. New agricultural load patterns resulting from this conversion process are still not fully reflected in marginal cost data which underlie the revenue allocation calculations. CFBF agrees with PG&E that the agricultural rate study ordered by the GRC decision could serve as a basis for changing allocations, and that the Commission might "overshoot" the EPMC target if it moves too quickly towards current EPMC estimates. Moreover, CFBF argues that marginal cost ratemaking is in its infancy. According to CFBF, until cost of service analysis progresses to a more exact process, the Commission's rush to a full EPMC allocation must be balanced against the negative impact that can be experienced by certain groups.

In addition to the uncertainty it finds with marginal cost ratemaking, CFBF points to additional factors which, it believes, support its recommendation. First, agricultural customers as a class received an increase of 8.3% last year, with most schedules receiving almost 10%. When combined with this year's increase and other anticipated increases, CFBF states that cumulative effect could be increases which exceed 40%. Second, CFBF notes that the benefit to other classes from more rapid movement of agriculture to EPMC is small when measured by customer billings. For example, when the 8% cap proposed by TURN is compared with the 2% cap proposed by PG&E, the result is an average savings of $4 per year for each residential customer and an average increase of $200 per year for each agricultural account.

c. TURN

TURN points out that there has been virtually no progress in moving the agricultural class towards EPMC since the Commission began a program of aggressive implementation of EPMC-based allocations in 1986 by D.86-08-083. Since that decision, residential rates have increased by 36.9%, or 13.2% more than SAPC, while agricultural rates have increased by 24.1%, or just 0.4% more than SAPC. The migration of agricultural customers to lower cost rate schedules has almost completely offset the minor increases that have occurred. To achieve what it considers significant progress in moving the agricultural class to EPMC, TURN proposes capping the agricultural class at SAPC plus 8% and all other classes at SAPC plus 5%.

TURN believes that proposals of the other parties for lower caps do not provide for sufficient progress in reducing the agricultural subsidy, particularly in light of the small 2% cap applied in the GRC. TURN states that if the Commission had adopted a 5% cap in the GRC, it probably would have recommended a 5% cap at this time. TURN notes testimony showing that if a 2% cap above SAPC were to be consistently applied in PG&E's revenue allocation proceedings, it could take as long as 19 years to achieve full EPMC for the agricultural class. Even though that estimate is subject to certain assumptions, TURN believes it is clear that a 2% cap cannot result in reasonable progress.

TURN also disagrees with the 2% floor proposed by PG&E because it can distort the revenue allocation process. Under some scenarios a 2% floor may result in failure to allocate all revenues.

d. CLECA

CLECA witness Barkovich initially advocated a cap and floor of 5% above and below SAPC. Barkovich acknowledged, however, that a more uniform sharing of the agricultural subsidy results without a floor. CLECA therefore supports implementation of full EPMC allocation with a cap of 5% on individual classes and no floor on class decreases. CLECA does not oppose TURN's proposed 8% cap for agricultural customers.

Like TURN, CLECA favors achieving significant progress toward the Commission's frequently-stated goal of a full EPMC revenue allocation in this case. It characterizes the progress to date in phasing in EPMC as "excruciatingly slow". CLECA notes that with the sole exception of the agricultural class, PG&E's customers are paying a relatively even share of the overall revenue requirement burden on an EPMC basis. The agricultural class pays far below its EPMC share, which is not only unfair, but sends incorrect pricing signals. CLECA urges that this problem be corrected faster than recommended by either PG&E or DRA.

CLECA also faults PG&E's and DRA's proposals because they inadequately allocate the remaining revenue requirement (after allocation to agriculture) among the other classes. The combination of caps and floors recommended by those parties results in a narrow range that can create disproportionate allocation burdens and anomalies such as inability to allocate the total revenue requirement. As an example, CLECA refers to DRA's 3.5% cap and floor proposal, which, although it manages to allocate 100% of the revenue, causes disproportionate impacts on the residential class and the E-19 class since they are the only classes left after the others have hit caps or floors. Under this proposal, the nonagricultural classes pay anywhere from 100.08% to 103.26% of the full EPMC allocation. By removing the floor, the 3.5% cap yields a more even allocation with all but one nonagricultural class paying the same 102.55% of full EPMC. A similar leveling of the revenue burden occurs when the floor is removed from CLECA's 5% capped allocation.

e. Industrial Users

Industrial Users share TURN's and CLECA's concern about the lack of meaningful progress in eliminating the subsidy to agriculture. While they recognize the need to balance two separate and distinct policies of moderated rate increases and cost-based rates, they urge adoption of a cap of at least 5% above SAPC and no floors. Industrial Users also urge adoption of TURN's proposed 8% cap for the agricultural class to "rectify" the negligible progress of that class towards full EPMC over the last three years. Industrial Users note that under PG&E's proposal, the subsidy to agriculture would be approximately $150 million. TURN's proposal for an 8% cap over SAPC reduces that subsidy by approximately $19.9 million, which Industrial Users consider a modest reduction.

f. CMA

CMA believes that the Commission's revenue allocation proceedings have focused too much effort on formula approaches to setting the proper caps and floors and too little attention on the reasonableness of the end result. CMA suggests that a more equitable procedure is to simply allocate revenues so that all unprotected classes pay the same percentage of marginal cost. For this proceeding, this would ensure that the agricultural subsidy is borne in equal proportion by all other classes.

Assuming the agricultural class is capped at SAPC plus 5%, CMA submits that an allocation based on a cap of SAPC plus 5% for all classes and no floors best achieves an equal sharing of the agricultural subsidy. However, CMA would support the reduced agricultural subsidy inherent in TURN's 8% cap proposal.

g. DRA

In its initial proposal, DRA recommended uniform caps and floors of 3.5% above and below the SAPC. DRA would prefer adopting the guideline figure of 5%, but because of the impacts of overall system increase, it believes that the rate shock would be too great for some schedules. Even with DRA's 3.5% proposal for interclass (and intraclass) allocation, some agricultural schedules would be increased by almost 20%. Under the 5% cap of other parties, some schedules would face increases of more than 20%. On the other hand, DRA believes that PG&E's 2% proposal makes too little progress in moving agriculture to full EPMC.

In its reply brief, DRA modified its position somewhat by recommending a "no-decrease" floor instead of a floor of SAPC minus 3.5%. DRA agrees with the arguments of CLECA and CMA that removing the floor can more equitably distribute the agricultural subsidy than a 3.5% floor. DRA had originally used a symmetrical approach for consistency with the GRC decision, but finds that the criticisms of traditional symmetrical caps and floors have considerable merit. Based on the extensive modeling work performed by CLECA (Exhibit 49), DRA believes that maintaining symmetry may indeed create inequities. Because there is a system increase in this case, DRA believes that a no-decrease floor (instead of no floor) is the more equitable approach.

2. **Discussion**

All of the parties have recognized our commitment to marginal cost pricing through the EPMC method. With the exception of CFBF, all of the parties have recommended that at least some progress be made towards reducing the variance between current allocations and the ultimate goal of a full EPMC allocation for all classes. At the same time, no party has recommended moving the agricultural class to a full EPMC allocation in this proceeding, apparently in recognition of the severe rate shock that would be associated with a 58% increase in average rates for the class. The issue is whether any increase over and above the SAPC should be imposed on the agricultural class at this time, and if so, to what extent should progress to full EPMC be moderated. We are presented with a range of proposals ranging from SAPC only as recommended by CFBF to SAPC plus 8% as proposed by TURN and supported by CLECA, CMA, and Industrial Users. The proposals of PG&E and DRA fall within this range.

For the reasons explained below, we conclude that the approach recommended by DRA, which includes a cap of SAPC plus 3.5% and a no-decrease floor, provides the best balance of our goals of achieving a full EPMC allocation and avoiding excessively large rate increases for any particular customer class. Other proposals either move too slowly toward EPMC or result in unbearably large increases to some classes.

In weighing the impact of the substantial system rate increase and possible additional increases on the agricultural class, we cannot ignore the impact of the system increase and the agricultural subsidy burden on the other classes. As noted by CLECA, precisely because of the large system increase, the continuing burden of the agricultural subsidy on other customers is less tolerable in this case. For this reason, and because of our desire to achieve significant progress towards the EPMC allocation goal, we reject the proposal of CFBF for a cap of SAPC and that of PG&E for a cap of 2% above SAPC.

We also reject the suggestion that we are bound by our action in last year's GRC decision to adopt a cap of 2% at this time. One of our primary reasons for adopting a 2% cap in the GRC was our recognition of the conversion of agricultural customers to TOU schedules, and the impact such conversions could have on usage patterns. As CFBF points out, this situation still exists, and changing use patterns are still not fully reflected in the marginal cost elements that underlie the EPMC calculations before us today. Nevertheless, in this proceeding we must strike a balance based on all of the facts before us this year, including the large system increase and the impact it has on all classes. We view the TOU conversion process and the effect it may have on marginal cost assignments to the agricultural class as reasons for proceeding with caution at this time. As explained below, we believe that the 3.5% cap we are adopting for agriculture in fact represents a cautious approach.

We find CFBF's argument for limiting the agricultural rate increase because of the last year's increase of approximately 10% for most schedules to be unconvincing. Most of the increases which were faced by agricultural customers were also faced by the remaining customers. Similarly, we give little weight to the argument for attenuating the agricultural increase because the increase per account in dollar values far exceeds the decrease received by the average residential customer. In evaluating the overall interest of a class, we cannot discount the interest merely because the class is composed of large numbers of small users.

CFBF has characterized the other parties' proposals as an unjustified rush to EPMC given the uncertainty it finds with the present state of marginal cost analysis. However, given the minimal success achieved so far in progressing to EPMC and removing the agricultural subsidy, the 3.5% cap adopted today can scarcely be considered as a "rush" when the full EPMC revenue allocation requires a 58% class increase.

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. We are confident that our adoption of a cap of SAPC plus 3.5% in this case runs no reasonable risk of "overshooting" the EPMC target for agriculture.

On the other hand, we are persuaded the GRC guideline cap of 5% and the 8% cap recommended by TURN both result in excessive increases this year. The evidence indicates that a cap of 5% could lead to some agricultural schedules receiving increases in excess of 20%, with a class increase of approximately 16%. Under TURN's proposal the agricultural class receives an increase of 18.37%, and depending on the intraclass allocation method, individual schedules would receive in excess of a 20% increase. In our judgement, a revenue allocation which yields schedule increases exceeding 20% in this proceeding does not represent a reasonable balancing of our ratemaking goals.

We note that several parties seem to believe that our past actions in balancing these goals need to be rectified at this time. In essence, they are requesting that we adopt an increase for agriculture which exceeds an amount that would otherwise be reasonable in order to make up for earlier actions. We reject such an approach. Our goal has always been to move as soon as reasonably possible to full EPMC for all classes. Adopting a cap of 3.5% above SAPC does not rectify past actions, nor is it intended to. Instead, it represents our judgement with respect to the maximum reasonable progress we can achieve now.

Although we have determined that a 3.5% cap above SAPC is appropriate, we agree with DRA and other parties that a symmetrical floor of 3.5% below SAPC may cause unnecessary distortions in the allocation to the various classes. The extensive revenue allocation modeling presented by CLECA shows that with the large system increase and with caps of 2%, 3.5%, or even 5%, the allocation is more equitable without a symmetrical floor. Rather than adopting an allocation with no floors, we will adopt the more conservative approach recommended by DRA to impose a floor of no decrease. This results in an allocation in which most nonagricultural classes are paying the same percentage of the full EPMC allocation, which we agree is more equitable.

Given the wide variance between current agricultural rates and the rates associated with the full EPMC allocation, it appears likely that the issue of agricultural rates will be present in revenue allocation proceedings for some time to come. Because we wish to achieve our EPMC goal as quickly as reasonably possible, we are disappointed by the lack of information in this record on the ability of the agricultural class to tolerate rate increases. While we are very concerned about rate increases exceeding 20% and have refrained from imposing such increases in this decision, we are not fully convinced that such increases cannot or should not be tolerated in future years. We cannot simply accept CFBF's assertion about rate shock that "you'll know it when you see it." We would prefer to rely on more objective data on the demand of the agricultural class. 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 or required by the nature of the demand of agricultural customers for electric service.

C. **Streetlighting**

In the GRC decision we stated our intent to move the streetlighting class to full EPMC within three years. We moved that class one-third of the way in that decision. We determined that the effect on other customers would be minor. (D.89-12-057, p. 240.)

1. **The Parties' Positions**

CAL-SLA proposes moving the streetlighting class to its full EPMC allocation. CAL-SLA disagrees with DRA's proposal to the extent it limits any rate decrease that would otherwise be enjoyed by the class. CAL-SLA also proposes adoption of an energy charge of $0.07165 per kWh.

To be consistent with the GRC decision, PG&E proposes moving the streetlighting class to the higher of full EPMC or one-half the distance between present allocation and full EPMC. Under PG&E's proposal this results in an increase of approximately 1.8%. PG&E disagrees with CAL-SLA's request to adopt a specific energy charge. As noted, DRA recommends moving the class one-half of the way to EPMC, resulting in a decrease of 0.9% under its proposal.

TURN states that it takes no position on the allocation for the streetlighting class except to note its past support for more rapid movement of the class to full EPMC, its small size, and its public character. Similarly, CLECA did not take a position on streetlighting rates, although its witness noted the minimal impact on other classes.

2. **Discussion**

We find there is in fact little real controversy on the allocation proposals for this class. As PG&E witness Horii testified, the difference between the DRA's and PG&E's EPMC calculations is likely due to the different ERI values used to adjust the marginal generating capacity cost. Thus, DRA's recommendation is offered in the context of a decrease for the class while PG&E's recommendation is offered in the context of an increase.

With this understanding, we find that the proposals are consistent with each other and with our stated intent in the GRC decision. As shown in Appendix B, our adopted marginal costs result in an EPMC-based increase of 1.73%. Adoption of this increase on a full EPMC basis is consistent with the recommendations of all of the parties as well as the GRC decision. We agree with PG&E that adoption of CAL-SLA's specific energy charge proposal is inappropriate because it is based on an illustrative revenue requirement. The adopted energy charge will reflect the final, adopted revenue requirement and revenue allocation criteria.

V. Intraclass Revenue Allocation

Once revenue is allocated to the customer classes, the revenue responsibility determined for each class must be divided among the various tariff schedules making up the class. In the GRC decision we adopted a guideline for intraclass allocation consistent with that adopted interclass allocations. This consists of a cap of 5% above the class average percentage change (CAPC) and a floor of 5% below the CAPC. (D.89-12-057, pp. 252-253.) This approach was applied to all but the AG-5 schedules.[2] Because of our concern over the possibility of bypass, we set the revenue responsibility for AG-5 equal to its marginal cost revenue responsibility to aid in keeping the schedule competitive with alternative pumping fuels. (Id., p. 253.)

2 References to AG-5 schedules and AG-5 rates in this section apply to Schedules AG-5B and AG-5C only, and not to Schedule AG-5A.

A. **The Parties' Positions**

PG&E proposes using the GRC guideline of CAPC plus and minus 5%. Because of the relatively low allocation to the AG-5 schedules that generally results under the GRC method, and the correspondingly higher allocation to the other agricultural schedules, PG&E recommends a capped EPMC allocation to the AG-5 schedules and an equal percentage increase to the other schedules to recover the class' remaining revenue. PG&E notes that under DRA's application of the GRC approach, AG-5 rates would receive an approximate 8% increase while the remaining agricultural schedules would receive nearly a 20% increase, which it considers excessive. PG&E states that its capped EPMC approach for AG-5 results in increase of 10.5% for AG-5, thereby moderating the increases to the other schedules. PG&E agrees with testimony of TURN (described below) that AG-5 schedules can bear this additional increase.

DRA recommends consistency with its interclass allocation, and therefore recommends a cap of CAPC plus 3.5% and a no-decrease floor. (DRA initially recommended a floor of CAPC minus 3.5%, but subsequently revised this recommendation for consistency with its revised interclass floor recommendation.) DRA also initially used the GRC guideline for the AG-5 schedules by allocating those schedules the EPMC share of intraclass revenues with a floor of marginal cost revenue responsibility. Upon further review, DRA agreed with PG&E, CFBF, and TURN that additional increases could be assigned to the AG-5 schedules. DRA recommends assigning a uniform increase to all of the agricultural schedules, including AG-5.

TURN opposes PG&E's 5% cap because it results in a wide gap between increases for residential TOU and seasonal schedules and increases for the other residential schedules. TURN believes that using the same caps for intraclass as for interclass allocation results in a more equitable distribution of the revenue increase among residential customers.

TURN also believes that a larger increase can be adopted for the AG-5 schedules than that which results from the GRC method used by DRA, while at the same time the ability of those schedules to compete with alternative pumping fuels is preserved. The study which found AG-5 rates to be competitive with diesel pumping used a diesel price of 55 cents per gallon. (D.90-04-022.) TURN's witness Marcus estimates that that the rise in fuel prices since the time of that decision has raised the cost of diesel pumping by approximately 3.7 cents per kWh. This is expected to decline somewhat next summer based on futures prices, but will still be 2.9 cents per kWh higher than the cost adopted in D.90-04-022.

CFBF believes that under any adopted proposal, AG-5 rates can be raised by an amount which is at or near the system average increase. While mindful of the Commission's desire to keep the AG-5 schedules competitive with alternative pumping fuels, CFBF agrees with TURN that world events affecting fuel prices permit such an increase while preserving competition.

B. Discussion

We agree with TURN and DRA that consistency of interclass and intraclass caps and floors is desirable because the need to ameliorate increases to individual schedules is just as important as the moderation of class increases. We will adopt DRA's recommendation for a cap of 3.5% over CAPC and a no-decrease floor.

No party has challenged TURN's showing that the AG-5 schedules can bear larger increases than those first proposed by DRA. On the other hand, we are not persuaded that an estimated increase in diesel pumping costs of 2.9 cents per kWh during the next pumping season justifies an AG-5 increase of more than 14% as recommended by DRA. We are persuaded that an increase equal to the SAPC as suggested by CFBF is justified, and will so provide. Compared to DRA's original proposal, which yielded increases of nearly 20% for the remaining agricultural schedules, this will require smaller increases of approximately 15% to 16% for those schedules.

VI. Rate Design Issues

As previously noted, we have determined that rate design issues are more appropriately considered in GRCs and their related rate design window proceedings than in ECAC proceedings. However, issues can arise in the application and interpretation of established rate design criteria. Two such issues have arisen in this case.

A. Residential Tier Differentials

Proposals to close the current residential tier differential (the difference between the lower baseline or "Tier 1" rate and the higher Tier 2 rate) will be addressed in PG&E's pending rate design window proceeding. However, a disagreement arose over the method by which the differential should be maintained for the time being.

1. The Parties' Positions

Currently, PG&E's Tier 2 rate is 3.446 cents/kWh, or 36.7%, higher than the Tier 1 rate. The rate proposals of both PG&E and DRA maintain a constant cents/kWh differential between the Tier 1 and Tier 2 rates. Due to the overall increase in rates, this method reduces the differential (based on PG&E's rate proposal) on a percentage basis to 32.3%.[3]

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3 PG&E and DRA presented slightly different calculations of the current composite Tier 1 rate. (Exhibits 52 and 54.) PG&E shows the composite Tier 1 rate to be 9.396 cents/kWh, while DRA shows it to be 9.411 cents/kWh. Related calculations of the tier differentials vary accordingly. DRA does not explain its difference with the current composite Tier 1 rate calculation presented by PG&E. We accept PG&E's calculation, and for clarity our discussion refers only to it.

TURN opposes this method, arguing that by maintaining a constant cents/kWh differential, PG&E and DRA are improperly proposing to reduce the percentage differential. TURN requests that the 36.7% differential be maintained. TURN notes that the Commission reduced the tier differential by 25% in the last GRC, and that the 36.7% differential for PG&E's electric rates is already the lowest of any major California utility. TURN argues that no reason exists for further reduction in that differential.

PG&E and DRA argue that maintenance of a constant cents/kWh differential is consistent with prior Commission decisions. (D.88-12-031 and D.89-12-057.) PG&E also argues that TURN's methodology results in rates which violate the spirit of SB 987, the baseline reform legislation, by establishing a wider tier differential in cents/kWh and a higher non-baseline rate. Finally, PG&E believes that the issue of whether to maintain the differential in percentage or absolute terms is more properly addressed in the rate design window.

2. Discussion

TURN is correct when it observes that if the absolute value of the tier differential is unchanged while both tiers increase, the tiers have moved closer together in percentage terms. At the same time, PG&E and DRA are correct in observing that if the percentage differential is left unchanged while the Tier 1 and Tier 2 rates are increases, the differential will increase in absolute terms. (Under PG&E's rate proposal, the absolute differential is increased by 11.9% from 3.446 to 3.856 cents/kWh if the percentage is unchanged.) Both observations are necessary arithmetical results of the underlying assumptions.

It is not possible to maintain a constant tier differential in both absolute and percentage terms when the rates are being increased. Thus, the real disagreement concerns the definition of "tier differential". If it is defined as an absolute value, PG&E and DRA are correct. If it is defined as a percentage value or a ratio, then TURN is correct.

For a definition of "tier differential" we look for guidance to our prior decisions. As noted by PG&E and DRA, in D.88-12-031 we stated that "(r)ather than setting the Tier I rate on a percentage basis, we believe that the absolute differential between the Tier I (baseline) and Tier II rates of Schedule E-1 recently adopted in D.88-10-062 should be maintained." (D.88-12-031, p. 22 and Conclusion of Law 8, p. 24.) Similarly, as noted by both PG&E and DRA, in D.89-12-057 we provided for a 25% reduction in the differential "expressed in cents/kWh." (D.89-12-057, p. 262 and Conclusion of Law 94, p. 447.) It is therefore clear that in those decisions we implicitly defined the term as an absolute value. We will not abruptly change that definition at this time without further consideration of the issue. That consideration should take place in rate design proceedings in conjunction with the broader issue of whether the tier differential should be adjusted further.

We will therefore adopt the PG&E and DRA proposal to maintain a constant cents/kWh differential in this proceeding.

B. Non-Firm Rates for E-19 and E-20 Customers

Both PG&E and DRA presented rate proposals which, apparently inadvertently, substantially change the rate design of firm and non-firm rates for E-19 and E-20 customers. There is agreement in principle on maintaining the status quo for E-19 and E-20 schedule rate design, but disagreement on specific proposals for accomplishing that end.

1. **The Parties' Positions**

PG&E's proposals in Exhibit 43 result in virtually no differences between the energy rates for firm and non-firm services. Instead, the differences are assigned to the on-peak demand charge. By contrast, the present rate design provides a significantly lower energy rate for non-firm customers. DRA's initial rate proposal adopted much the same approach.

CLECA argues, and other parties (including PG&E witness Horii) generally agree, that elimination of the energy rate discount for non-firm service would adversely impact customers with high load factors. DRA agreed that it was not its intent to do so in this case, and in response to a request from CLECA, submitted an alternative approach in late-filed Exhibit 54. In the alternative proposal, DRA maintains the current cents/kWh differential between the firm and non-firm energy charges for equivalent schedules and voltage levels.

In their opening briefs, CLECA, CMA, and Industrial users indicate their support for DRA's Exhibit 54 approach, at least pending a more detailed review in the pending non-firm rate design proceeding (A.88-12-005). CMA notes, however, that while Exhibit 54 corrects the energy rate problem, it reduces the demand charge differentials by as much as one-third. CMA further notes that demand charge differentials are more significant during the summer months, and that there is time to consider them in the non-firm proceeding. In its reply brief DRA itself indicates its preference for the Exhibit 54 approach while non-firm rate issues are debated further in the non-firm proceeding. In its reply brief, CMA withdrew its support for the Exhibit 54 approach. CMA now believes the only reasonable action is to leave all existing non-firm discounts in place pending the outcome of the non-firm proceeding.

PG&E agrees that its proposals in Exhibit 41 do not entirely accomplish the goal of continuing the E-19 and E-20 rate design adopted in the GRC, but it is also concerned that DRA's

Exhibit 54 approach results in anomalous on-peak demand charges. To remedy this problem, PG&E attached to its opening brief proposed revisions in an attempt to maintain the percentage of the current non-firm discounts which are embedded in the demand and energy charges.

CLECA expresses alarm that PG&E's opening brief proposal appears to reduce the overall amount of the non-firm discount by substantial amounts. Industrial Users agree, and urge that the proposal be disregarded. Likewise, CMA agrees that PG&E's latest proposal raises more problems than it resolves. These parties are concerned that the proposal involves an attempt by PG&E to resolve alleged errors in the rate design adopted in the last GRC. DRA similarly urges that the non-firm rate proposal submitted by PG&E with its opening brief not be adopted in this proceeding.

2. Discussion

We agree with CLECA, Industrial Users, and DRA that the approach offered by DRA in Exhibit 54 represents the best interim solution to the problem of non-firm discounts for the E-19 and E-20 schedules. While this method for preserving the discounts for non-firm energy charges results in anomalies in demand charges, there is an opportunity to resolve these problems prior to the summer of 1991, when on-peak demand charges take on greater significance. The schedule for PG&E's non-firm rate design proceeding provides for an effective date of rate changes of May 1.

Without addressing its merits, we must reject the latest proposal offered by PG&E with its opening brief. While the attempt to unravel this ratemaking snarl is commendable, we are reluctant to consider or adopt a proposal that engenders new controversy and raises as many new questions as it resolves, since the parties have had no reasonable opportunity to address these concerns.

Findings of Fact

1. D.90-10-062 adopted the 1990-91 ECAC, AER, ERAM, and LIRA revenue requirements adjustments for PG&E, with a net revenue change of $480,912,000 effective November 1, 1990.

2. D.90-10-062 authorized PG&E to defer implementation of rate changes authorized by that decision until January 1, 1991 to allow a single set of rate changes consolidating the $480,912,000 increase with adjustments from (1) PG&E's 1991 Attrition Rate Adjustment filing (Advice Letter 1319-E); (2) PG&E's 1991 Cost of Capital proceeding (Application (A.) 90-05-011); (3) PG&E's Customer Energy Efficiency proceeding (A.90-04-041; D.90-08-068); (4) PG&E's Earthquake Recovery Account proceeding (A.90-05-003); and (5) PG&E's Demand-Side Management/Research and Development offset (Resolutions E-3174 and E-3188).

3. Appendix A shows the development of the consolidated revenue requirement increase of approximately $688 million, which is based on the amounts that have been adopted or requested in the various proceedings.

4. PG&E's proposed marginal energy costs were uncontested, and were used by other parties in developing their revenue allocation proposals.

5. PG&E used the same series of ERIs that was adopted in the 1990 GRC, but updated the six-year average by deleting the 1990 value and adding the 1996 value.

6. PG&E's Phase 1B BRPU filing, which was made pursuant to specific directives in D.90-03-060, contains ERIs which have not been adopted by the Commission.

7. The resource plans considered in ECAC proceedings are short-term plans, while GRC and BRPU proceedings involve consideration of longer-term plans.

8. It is reasonable that the ERI values used in computing the six-year average ERI adjustment factor be drawn from the most

recently adopted series of values which are based on a long-term plan.

9. Appendix C contains the previously-adopted marginal costs which are carried forward from the GRO as well as the marginal energy costs and the ERI adjustment to the marginal generating capacity cost adopted by this order.

10. All parties endorse in principle the EPMC approach, with some limits to moderate the rate effects on particular classes.

11. Because the special contract rates are not increased by the revenue allocation process, inclusion of special contract revenues has the effect of lowering the SAPC and, therefore, of lowering the percentage increase applicable to capped classes, which in turn slows the movement of such classes to full EPMC allocation.

12. It would be inconsistent to exclude special contract sales, marginal costs, and revenues from the initial EPMC allocation but include such revenues for the purpose of defining caps.

13. Appendix B shows that for the consolidated 1991 PG&E revenue requirement increase, if each customer class were moved to its full EPMC allocation, the agricultural class rates would increase by 58.25%.

14. 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.

15. All of the parties, with the exception of CFBF, have recommended that at least some progress be made towards reducing the variance between current allocations and the ultimate goal of a full EPMC allocation for all classes.

16. No party has recommended moving the agricultural class to a full EPMC allocation in this proceeding.

17. Because of the large system increase, the continuing burden of the agricultural subsidy on other customers is less tolerable in this case than in previous cases.

18. A cap of 5% could lead to some agricultural schedules receiving increases in excess of 20% with a class increase of approximately 16%, and an 8% cap could result in a class increase of 18.37% with individual schedule increases in excess of a 20%.

19. A revenue allocation which yields schedule increases exceeding 20% in this proceeding does not represent a reasonable balancing of our ratemaking goals.

20. A cap of SAPC plus 3.5% and a no-decrease floor provide a reasonable balance of our goals of achieving a full EPMC allocation and avoiding large rate increases for any particular customer class, because other proposals either move too slowly toward EPMC or result in unbearably large increases to some classes.

21. The agricultural customer TOU conversion process and the effect it may have on marginal cost assignments to the agricultural class is a reason for proceeding with caution at this time, and the 3.5% cap we are adopting for agriculture represents a cautious approach.

22. For this proceeding, a no-decrease floor can result in a more even sharing of the agricultural subsidy burden by the remaining classes compared to a floor set at 3.5% or 5% below the SAPC.

23. There is 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.

24. The difference between the DRA's and PG&E's EPMC calculations for streetlighting is likely due to the different ERI values used to adjust the marginal generating capacity cost.

25. Adoption of the full EPMC allocation for streetlighting is consistent with the recommendations of all of the parties as

well as the GRO decision, and does not result in any significant adverse impact on other customer classes.

26. Consistency of inter and intraclass caps and floors is desirable because the need to ameliorate increases to individual schedules is just as important as the moderation of class increases.

27. The AG-5B and AG-5C schedules can bear larger increases than those first proposed by DRA, and an increase equal to the SAPC is justified.

28. It is not possible to maintain a constant residential tier differential in both absolute and percentage terms when the rates are being increased.

29. In D.88-12-031 and D.89-12-057 we implicitly defined the term tier differential as an absolute value.

30. The approach offered by DRA in Exhibit 54 represents the best interim solution to the problem of non-firm discounts for the E-19 and E-20 schedules.

31. There is an opportunity to resolve anomalies in demand charges and other problems for the E-19 and E-20 schedules prior to the summer of 1991, when on-peak demand charges take on greater significance.

32. Parties have had no reasonable opportunity to address concerns arising from the proposal of PG&E for E-19 and E-20 schedules submitted with its opening brief.

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

Conclusions of Law

1. PG&E's proposed marginal energy costs are uncontested and should be adopted.

2. ERI values which have been submitted by PG&E with a compliance filing in another proceeding, but which have not been

adopted in that proceeding, should not be used as a basis for adjusting the marginal generating capacity cost used in revenue allocation.

3. The ERI data series adopted in PG&E's GRC should be used in this proceeding for the purpose of adopting an ERI adjustment to the marginal generating capacity cost.

4. Special contract revenues should be excluded from the calculation of the SAPC which is used to define revenue allocation caps and floors.

5. For interclass revenue allocations, a cap on increases equal to the SAPC plus 3.5% should be adopted in this proceeding because of the size of the system increase, the need to avoid unbearably large increases for any class, the burden of the agricultural subsidy on other classes, and the need to make significant progress toward a full EPMC allocation for all classes.

6. To achieve an equitable distribution of the agricultural subsidy burden among the other classes, a floor of no decrease in the allocation to any class should be adopted.

7. The revenue allocation for the streetlighting class should be set at its full EPMC allocation.

8. DRA's recommended intraclass allocation cap of CAPC plus 3.5%, and its recommended floor of no decrease, should be adopted for consistency with the adopted interclass allocation.

9. The AG-5B and AG-5C schedules should be increased by the SAPC.

10. Our existing methodology of adjusting residential rate tier differentials on a cents/kWh basis should be followed in this proceeding.

11. DRA's Exhibit 54 approach for rate design for the E-19 and E-20 schedules should be adopted on an interim basis pending a more detailed review in the non-firm rate design proceeding arising from PG&E's 1990 GRC.

12. PG&E should be authorized to implement the consolidated revenue requirement adjustment shown in Appendix A effective January 1, 1991 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 (PG&E) 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 Appendix D.

2. The revised tariff schedules shall become effective on or after January 1, 1991 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 19, 1990, at San Francisco, California.

G. MITCHELL WILK
President
FREDERICK R. DUDA
STANLEY W. HULETT
JOHN B. OHANIAN
PATRICIA M. ECKERT
Commissioners

We will file a written concurring opinion.

/s/ FREDERICK R. DUDA
Commissioner

/s/ JOHN B. OHANIAN
Commissioner

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

A.90-04-003
D.90-12-066

FREDERICK R. DUDA, Commissioner, concurring:

I generally concur with today's decision. My concern deals with the continuing slow pace by which this Commission is moving to implement electric revenue allocation among customer classes for Pacific Gas & Electric (PG&E) based on an equal percentage of marginal cost (EPMC) approach. It has been over four years since the Commission in D.86-08-083 began a program to implement EPMC-based allocations. With today's decision we still find ourselves far from the goal of EPMC-based allocation rates for PG&E. The agricultural customer class is paying four and one-half cents below its EPMC allocation while other customer classes are paying between one and three mills per kilowatt-hour above their EPMC allocation.

Only a year ago the Commission in D.89-12-057 adopted marginal costs for all customer classes. More recently, the Commission undertook a joint study with PG&E to examine agricultural marginal costs. Although this report is not final, it is clear from the scenarios that are being examined that the agricultural customer class "is below an EPMC allocation by a significant margin in every instance."[1]

As is stated in today's decision the Commission finds itself constrained to move more aggressively toward an EPMC allocation for the agricultural class because of the need to

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1 Second draft of the PG&E/CPUC Joint Agricultural Cost Study dated October 5, 1990, p. ES-4.

balance the competing goal of avoiding excessively large rate increases for any particular customer class. I believe the Commission finds itself in this position because it did not establish a process for implementation, including a timetable, at the time it adopted the policy of an EPMC-based allocation.

If there is a lesson to be learned from this situation, it is that the Commission must follow through on its policy pronouncements with an explicit and well structured implementation program that achieves the policy objectives that are sought. Failure to structure a specific implementation program leads to a situation where our policy goals and objectives are delayed and the condition we want to change may in fact worsen. This is clearly the case here where the great majority of ratepayers are continuing to cross subsidize the agricultural class. Movement toward an EPMC-based allocation for all classes is our adopted goal and objective. We should adopt a plan and stay with the plan with deviations only under emergencies.

I would urge the Commission in the future to support its policy directives by explicitly endorsing an implementation program that achieves the policy objectives in an efficient and timely manner with exceptions and limits firmly controlled.

Frederick R. Duda

Frederick R. Duda, Commissioner

December 19, 1990
San Francisco, California

A.90-04-003
D.90-12-066

John B. Ohanian, Commissioner, concurring:

This is a good decision that made many tough choices while balancing difficult and competing interests. I wish to Commend Commissioner Eckert for her handling of the case.

Among the tough decisions made was that to raise agriculture rates by up to 16%. The primary reasons for so doing is that ag rates are "below cost" and must be brought into alignment with cost. Otherwise, the argument goes, ag rates are kept artificially low at the expense of residential and other customer classes.

This train of logic assumes facts that may not be in existence. Marginal cost ratemaking remains an inexact science. For instance, agricultural customers have been undergoing a conversion to time-of-use schedules. New agricultural load patterns resulting from this conversion process are still not firmly reflected in marginal cost data which underlie the revenue allocation calculations. Furthermore, the agricultural customer class does not represent a growing source of demand for electricity. Yet the EPMC allocation process assumes agricultural customers should pay for costly new capacity, transmission, and distribution resources. Until cost-of-service analysis progresses to a more refined stage, it would be premature to assume ag customers are paying less than their full share.

Parity in allocation of revenue requirement among customer classes is a fundamental goal; and through this decision, we continue to make steady progress toward achieving this goal. But I recommend prudent caution until we have before us a full understanding of the issues and facts. To this end, I will be bringing to my colleagues a set of recommendations for examining and resolving the remaining issues surrounding the appropriate level of agricultural electric rates.

John B. Ohanian, Commissioner

December 19, 1990
San Francisco, California

APPENDIX A
Page 1

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
Summary of Revenue Changes
Effective January 1, 1991

	REVENUE ELEMENT	PRESENT RATE REVENUE 1/ ($000's)	REVENUE CHANGE ($000's)	ADOPTED REVENUE REQUIREMENT ($000's)	ADOPTED AVERAGE RATE 2/ (cents/kwh)
	Energy Cost Adjustment Clause (ECAC)				
1	Adopted ECAC Costs	$3,271,320	($10,171)	$3,261,149	
2	Estimated ECAC account balance as of 10/31/90	0	521,656	521,656	
3	Designated Sales Transactions to Resale Customers	(93,525)	0	(93,525)	
4	Subtotal	3,177,795	511,485	3,689,280	
5	Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	31,359	31,359	
6	Total ECAC Retail Revenues	$3,177,795	$542,844	$3,720,639	5.364
	Annual Energy Rate (AER)				
7	Adopted AER Costs	$194,336	$22,706	$217,042	
8	Designated Sales Transactions to Resale Customers	(9,250)	0	(9,250)	
9	Subtotal	185,086	22,706	207,792	
10	Franchise Fees & Uncollectible Accounts Expense @ 0.85%	0	1,766	1,766	
11	Total AER Retail Revenues	$185,086	$24,472	$209,558	0.302
	Base Energy Revenues (ERAM)				
12	Authorized Base Revenue Amount for 1990	$3,148,473	$174,379	$3,322,852	
13	DC Basic Revenue Requirement	0	(5,001)	(5,001)	3/
14	Environmental Compliance	0	1,941	1,941	3/
15	DSM/RD&D Refund Termination	0	29,217	29,217	4/
16	Customer Energy Efficiency Programs	0	38,713	38,713	3/
17	Earthquake Recovery	0	4,222	4,222	3/
18	Operational & Financial Attrition for 1991	0	128,594	128,594	3/
19	Subtotal Base Revenue Amount for 1991	3,148,473	372,065	3,520,538	
20	LIRA Shortfall	0	(26,146)	(26,146)	
21	Designated Sales Transaction to Resale Customers	(53,392)	0	(53,392)	
22	Estimated ERAM account balance as of 10/31/90	0	(211,921)	(211,921)	
	Debits to ERAM:				
23	1990 Calif. Corp. Franchise Tax Adjustment	0	1,944	1,944	3/
24	Environmental Compliance	0	2,093	2,093	3/
25	Earthquake Recovery	0	5,643	5,643	3/
26	Subtotal Debits to ERAM	0	9,680	9,680	
27	Total ERAM Retail Revenues	$3,095,081	$143,678	$3,238,759	4.669
	Low Income Rate Assistance (LIRA)				
28	LIRA Shortfall	$34,170	($8,024)	$26,146	
29	Estimated LIRA account balance as of 10/31/90	0	(16,667)	(16,667)	
30	Administrative Costs	0	1,975	1,975	
31	Total LIRA Revenues	$34,170	($22,716)	$11,454	0.017
32	Conservation Financing Adjustment (CFA)	$1,388	$0	$1,388	
33	California Public Utilities Commission Fees	$8,331	$0	$8,331	
34	TOTAL RETAIL REVENUES	$6,501,851	$688,278	$7,190,129	10.366
35	PERCENTAGE INCREASE		10.59%		

PACIFIC GAS & ELECTRIC COMPANY
ELECTRIC DEPARTMENT
Summary of Revenue Changes
Effective January 1, 1991

1/ = Based on rates effective 7/6/90.
2/ = Average Rates based on the forecasted retail sales of 69,360 GWh.
3/ = Adopted in Resolution E-3207.
4/ = Adopted in Resolution E-3174 and E-3183.

(End of Appendix A)

APPENDIX B
PAGE 1

PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED REVENUE ALLOCATION 1/2/3/4/
EFFECTIVE JANUARY 1, 1991

All Revenues in Thousands of Dollars

Line	A	B Total Sales (MWh)	C Present Revenue at 7/8/90 Rates	D Present Revenue at EPMC	E % Change	F Revenue Allocation at EPMC	G % Change	H Revenue Allocation at SAPC	I % Change	J Adopted Revenue Allocation	K % Change
1	Residential	23,944,561	$2,512,247	$2,474,809	-1.49%	$2,737,500	8.97%	$2,779,041	10.62%	$2,808,527	11.79%
2	Agricultural	3,311,551	$336,256	$480,989	43.04%	$532,116	58.25%	$371,518	10.49%	$383,141	13.94%
3	Streetlighting	285,849	$36,532	$34,745	-4.89%	$37,162	1.73%	$39,145	7.15%	$37,162	1.73%
4	Small L&P	7,586,359	$878,149	$900,557	2.55%	$996,240	13.45%	$971,376	10.62%	$1,001,966	14.10%
5	Medium L&P	13,526,678	$1,256,355	$1,173,159	-6.62%	$1,296,292	3.18%	$1,388,610	10.53%	$1,329,499	5.82%
6	E-19 Class	3,988,101	$349,326	$347,159	-0.62%	$383,745	9.85%	$386,150	10.54%	$393,588	12.67%
7	E-20 Class Tariff	14,797,375	$1,024,938	$982,387	-4.15%	$1,099,025	7.23%	$1,146,241	11.84%	$1,128,199	10.07%
8	Contracts	1,854,364	$108,048	$108,048	0.00%	$108,048	0.00%	$108,048	0.00%	$108,048	0.00%
9	TOTAL SYSTEM	69,294,838	$6,501,851	$6,501,851	0.00%	$7,190,129	10.59%	$7,190,129	10.59%	$7,190,129	10.59%
10	TOTAL INCREASE					$688,278		$688,278		$688,278	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, and (h) LIRA revenues.

2/ Negotiated contract revenues are excluded from the allocation process and held constant at present levels.

3/ 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.

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

5/ 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 10.96% rather than 10.59%.

APPENDIX B
PAGE 2
PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED INTRACLASS NET REVENUE ALLOCATION 1/2/3/4/
EFFECTIVE JANUARY 1, 1991

All Revenues In Thousands of Dollars

	A Class/Rate Schd Vol Lvl	B Sales	C Average Marginal Cost	D Net 7/8/90 rate Revenue	E Average 7/8/90 Rates	F Net Present Revenue at EPMC	G % Change	H Net Revenue at EPMC	I Average Rates at EPMC	J % Change	K Net Adopted Revenue	L Average Adopted Rates	M % Change	
	RESIDENTIAL:													
1	E-1 S	21,417,668	$0.07552	$2,279,089	$0.10641	$2,381,964	-1.15%	$2,635,231	$.11509	9.36%	$2,553,549	$.11923	12.04%	1
2	EL-1 S	1,479,007		$130,809	$0.08831						$147,176	$.09951	12.68%	2
3	E-7 S	853,121	$0.06048	$79,426	$0.09310	$75,218	-5.30%	$82,789	$.09704	4.23%	$84,743	$.09933	6.69%	3
4	E-8 S	194,764	$0.06449	$23,091	$0.11856	$17,568	-23.92%	$19,415	$.09969	-15.92%	$23,024	$.11822	-0.29%	4
	Standby			$31		$59	87.81%	$65		108.51%	$34		9.09%	
5	TOTAL	23,944,561	$0.07490	$2,512,247	$0.10492	$2,474,809	-1.49%	$2,737,500	$.11433	8.97%	$2,808,527	$.11729	11.79%	5
	AGRICULTURAL													
6	AG-1A S	231,754	$0.21975	$40,813	$0.17609	$70,897	73.72%	$78,580	$.33907	92.55%	$47,534	$.20511	16.48%	6
7	AG-RA S	18,383	$0.14550	$2,126	$0.11565	$3,887	82.82%	$4,291	$.23342	101.83%	$2,451	$.13334	15.29%	7
8	AG-VA S	40,570	$0.13332	$4,608	$0.11358	$7,794	69.14%	$8,604	$.21208	86.73%	$5,318	$.13108	15.41%	8
9	AG-4A S	107,413	$0.14600	$12,520	$0.11656	$22,599	80.50%	$24,953	$.23231	99.30%	$14,442	$.13446	15.35%	9
10	AG-5A S	85,260	$0.08951	$7,665	$0.08990	$10,881	41.97%	$12,015	$.14092	56.76%	$8,871	$.10404	15.74%	10
11	AG-1B S	658,386	$0.12211	$86,196	$0.13090	$112,066	30.03%	$124,094	$.18848	43.99%	$100,311	$.15236	16.39%	11
12	AG-RB S	33,770	$0.11246	$3,731	$0.11048	$5,351	43.42%	$5,918	$.17525	58.63%	$4,331	$.12824	16.08%	12
13	AG-VB S	26,101	$0.11349	$2,850	$0.10917	$4,175	46.53%	$4,618	$.17693	62.05%	$3,307	$.12671	16.06%	13
14	AG-4B S	401,762	$0.11304	$41,626	$0.10361	$63,879	53.46%	$70,663	$.17568	69.76%	$48,319	$.12027	16.08%	14
15	AG-4C S	29,522	$0.13007	$3,007	$0.10187	$5,408	79.82%	$5,983	$.20267	98.94%	$3,468	$.11816	15.99%	15
16	AG-5B S	1,636,616	$0.07419	$128,260	$0.07837	$170,241	32.73%	$158,185	$.11498	46.72%	$141,602	$.08652	10.42%	16
17	AG-5C S	42,014	$0.06467	$2,865	$0.06819	$3,802	32.72%	$4,202	$.10001	46.67%	$3,162	$.07525	10.36%	17
	Standby			$4		$8	87.33%	$9		108.53%	$5		9.09%	
18	TOTAL	3,311,551	$0.10355	$336,256	$0.10154	$480,989	43.04%	$532,116	$.15068	58.25%	$383,141	$.11570	13.94%	18
19	STREETLIGHTS S	285,549	$0.05559	$36,532	$0.12780	$34,745	-4.89%	$37,162	$.13001	1.73%	$37,162	$.13001	1.73%	19
	SMALL L&P													
20	A-1 S	7,347,562	$0.08563	$853,750	$0.11620	$878,754	2.93%	$972,129	$.13231	13.87%	$977,045	$.13298	14.44%	20
21	A-6 S	127,746	$0.05813	$12,705	$0.09948	$10,569	-16.84%	$11,657	$.09125	-8.25%	$12,665	$.09914	-0.35%	21
22	A-15 S	2,012	$0.19263	$416	$0.20689	$627	50.54%	$695	$.34050	64.56%	$475	$.23593	14.04%	22
23	TC-1 S	109,039	$0.06331	$11,217	$0.10287	$10,509	-6.32%	$11,661	$.10694	3.95%	$11,720	$.10748	4.48%	23
24	Standby			$57		$98	72.97%	$109		91.93%	$61		7.67%	24
25	TOTAL	7,586,359	$0.06497	$878,143	$0.11575	$900,557	2.55%	$996,240	$.13132	13.45%	$1,001,966	$.13207	14.10%	25
	MEDIUM L&P													
26	A-10	10,182,516	$0.06500	$993,277	$0.09755	$925,650	-6.81%	$1,023,027	$.10047	3.00%	$1,043,473	$.10307	5.66%	26
27	A-11	3,344,163	$0.05272	$262,945	$0.07863	$247,156	-6.01%	$272,874	$.08160	3.78%	$279,564	$.08369	6.44%	27
28	Standby			$131		$352	169.61%	$391		199.16%	$141		8.02%	28
29	TOTAL	13,526,678	$0.06198	$1,256,355	$0.09288	$1,173,158	-6.62%	$1,296,292	$.09583	3.18%	$1,329,498	$.09829	5.82%	29
	E-19 CLASS													
30	E-19 T	23,437	$0.06440	$1,985	$0.08471	$2,759	39.00%	$3,051	$.13018	53.69%	$2,304	$.09829	16.04%	30
31	E-19/25 P	363,356	$0.05498	$28,912	$0.07964	$27,799	-4.18%	$30,753	$.08464	6.00%	$31,707	$.08726	9.29%	31
32	E-19/25 S	3,560,065	$0.06279	$315,133	$0.08852	312,342	-0.89%	$345,235	$.09697	9.55%	$355,908	$.09997	12.94%	32
35	A-RTP-19 S	41,243	$0.05799	$2,830	$0.06863	$3,372	19.15%	$3,723	$.09026	31.53%	$3,278	$.07943	15.83%	35
36	Standby			$366		$886	142.19%	$963		158.74%	$391		6.82%	36
37	TOTAL	3,968,101	$0.06232	$349,325	$0.08759	$347,159	-0.62%	$383,745	$.09622	9.55%	$393,588	$.09869	12.67%	37
	E-20 CLASS													
38	E-20 T	3,164,569	$0.03791	$169,257	$0.05349	$157,639	-6.86%	$176,118	$.05565	4.04%	$182,879	$.05779	8.03%	38
39	E-20 P	6,702,500	$0.04921	$473,728	$0.07068	$440,257	-7.06%	$495,453	$.07392	4.59%	$513,834	$.07666	8.47%	39
40	E-20 S	4,685,363	$0.05617	$363,210	$0.07752	$359,425	-1.04%	$399,748	$.08532	10.06%	$410,682	$.08765	13.07%	40
41	A-RTP-20 P	122,421	$0.04352	$8,210	$0.06706	$8,511	3.67%	$9,393	$.07673	14.41%	$9,207	$.07521	12.14%	41
42	A-RTP-20 S	122,421	$0.05301	$8,452	$0.06904	$9,118	7.88%	$10,065	$.08221	13.09%	$9,478	$.07742	12.14%	42
43	E-20 w/o Cntrcts, Stby	14,797,375	$0.04898	$1,022,866	$0.06912	$974,954	-4.68%	$1,090,777	$.07371	6.64%	$1,125,079	$.07610	10.09%	43
44	Contracts: T	520,139	$0.03803	$27,752	$0.05335	$27,752	0.00%	$27,752	$.05335	0.00%	$27,752	$.05335	0.00%	44
45	Contracts: P	1,313,273	$0.04557	$78,926	$0.06010	$78,926	0.00%	$78,926	$.06010	0.00%	$78,926	$.06010	0.00%	45
46	Contracts: S	20,832	$0.05122	$1,371	$0.06562	$1,371	0.00%	$1,371	$.06562	0.00%	$1,371	$.06562	0.00%	46
47	Standby			$2,072		$7,433	258.75%	$8,248		298.07%	$2,120		2.33%	47
48	TOTAL E-20	16,651,738	$0.04893	$1,132,986	$0.06804	$1,090,435	-3.76%	$1,207,074	$.07249	6.54%	$1,236,248	$.07424	9.11%	48
49	SYSTEM TOTAL	69,294,838	$0.06777	$6,501,851	$0.09383	$6,501,851	0.00%	$7,190,129	$.10356	10.59%	$7,190,129	$.10376	10.59%	49
50	Check	69,294,838		$6,501,851		$6,501,851		$7,190,129			$7,190,129		5	50
51	TOTAL INCREASE							$688,278			$688,278			51

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

2/ Negotiated contract revenues are excluded from the allocation process and held constant at present levels.

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

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

5/ 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 10.96% rather than 10.59%.

APPENDIX B
PAGE 3
PACIFIC GAS AND ELECTRIC COMPANY
ADOPTED INTRACLASS ALLOCATED REVENUE ALLOCATION 1/2/3/4/
EFFECTIVE JANUARY 1, 1991

All Revenues In Thousands of Dollars

	A Class/Rate Schd Volt Lvl	B Sales	C Average Marginal Cost	D Allocated 7-5-90 rate Revenue	E Average 7-5-90 Rates	F Allocated Present Rev at EPMC	G % Change	H Allocated Revenue at EPMC	I Average Rates at EPMC	J % Change	K Allocated Adopted Revenue	L Average Adopted Rates	M % Change	
	RESIDENTIAL:													
1	E-1 S	21,417,668	$.07552	$2,300,689	$0.10742	$2,404,557	-1.14%	$2,668,155	$0.11653	9.70%	$2,585,481	$.12072	12.38%	1
2	EL-1 S	1,479,007		$131,802	$0.08898						$148,169	$.10018	12.59%	2
3	E-7 S	853,121	$.06048	$75,968	$0.08903	$71,750	-5.54%	$79,815	$0.09332	4.82%	$81,570	$.09561	7.39%	3
4	E-8 S	194,764	$.06449	$22,990	$0.11804	$17,467	-24.03%	$19,381	$0.09951	-15.70%	$22,990	$.11804	0.00%	4
	Standby			$31		$59	87.91%	$65		108.51%	$34		9.09%	
5	TOTAL	23,944,561	$.07490	$2,531,269	$0.10571	$2,493,832	-1.48%	$2,767,217	$0.11557	9.32%	$2,836,244	$.11853	12.13%	5
	AGRICULTURAL													
6	AG-1 A S	231,754	$.21975	$40,730	$0.17575	$70,817	73.87%	$78,581	$0.33907	92.93%	$47,535	$.20511	16.71%	6
7	AG-RA S	18,383	$.14650	$1,984	$0.10794	$3,745	88.74%	$4,156	$0.22606	109.43%	$2,316	$.12597	16.71%	7
8	AG-VA S	40,570	$.13332	$4,335	$0.10685	$7,521	73.49%	$8,346	$0.20571	92.51%	$5,059	$.12470	16.71%	8
9	AG-4A S	107,413	$.14800	$11,728	$0.10918	$21,807	85.94%	$24,197	$0.22527	106.33%	$13,687	$.12742	16.71%	9
10	AG-5A S	85,260	$.08351	$7,396	$0.08674	$10,612	43.50%	$11,776	$0.13811	59.23%	$8,631	$.10123	16.71%	10
11	AG-1 B S	658,386	$.12211	$85,919	$0.13050	$111,800	30.12%	$124,056	$0.18842	44.39%	$100,273	$.1523[illegible]	16.71%	11
12	AG-R3 S	33,770	$.11245	$3,661	$0.10842	$5,281	44.25%	$5,860	$0.17353	60.06%	$4,273	$.12653	16.71%	12
13	AG-V3 S	26,101	$.11349	$2,793	$0.10702	$4,119	47.47%	$4,571	$0.17511	63.64%	$3,260	$.12489	16.71%	13
14	AG-4B S	401,762	$.11304	$40,900	$0.10180	$63,153	54.41%	$70,077	$0.17442	71.34%	$47,7[illegible]	$.11851	16.71%	14
15	AG-4C S	29,522	$.13007	$2,939	$0.09955	$5,340	81.68%	$5,925	$0.20070	101.60%	$3,430	$.11618	16.71%	15
16	AG-5B S	1,636,816	$.07419	$126,869	$0.07752	$168,850	33.09%	$187,360	$0.11448	47.68%	$140,777	$.08602	10.96%	16
17	AG-5C S	42,014	$.05467	$2,841	$0.06761	$3,778	33.00%	$4,192	$0.09978	47.58%	$3,152	$.07503	10.96%	17
	Standby			$4		$8	87.93%	$9		108.53%	$5		9.09%	
18	TOTAL	3,311,551	$.10355	$332,099	$0.10029	$476,832	43.58%	$529,104	$0.15978	59.32%	$380,129	$.11479	14.46%	18
19	STREETLIGHTS S	265,549	$.05559	$23,882	$0.08355	$22,095	-7.48%	$24,517	$0.08577	2.66%	$24,517	$.08577	2.66%	19
	SMALL L&P													
20	A-1 S	7,347,562	$.08563	$849,929	$0.11568	$874,934	2.94%	$970,848	$0.13213	14.23%	$975,765	$.13280	14.81%	20
21	A-6 S	127,746	$.05813	$12,466	$0.09759	$10,327	-17.16%	$11,459	$0.08970	-8.08%	$12,456	$.09759	0.00%	21
22	A-15 S	2,012	$.13253	$329	$0.16358	$540	63.92%	$599	$0.29753	81.89%	$358	$.19296	17.96%	22
23	TC-1 S	109,039	$.08331	$11,217	$0.10287	$10,509	-6.32%	$11,661	$0.10694	3.95%	$11,720	$.10743	4.48%	23
24	Standby			$57		$98	72.97%	$109		91.93%	$61		7.67%	24
25	TOTAL	7,586,359	$.08497	$873,999	$0.11521	$896,407	2.56%	$994,675	$0.13111	13.81%	$1,000,401	$.13187	14.46%	25
	MEDIUM L&P													
26	A-10	10,132,516	$.06500	$988,018	$0.09703	$920,391	-6.84%	$1,021,268	$0.10030	3.37%	$1,047,733	$.10290	6.04%	26
27	A-11	3,344,163	$.05272	$260,937	$0.07803	$245,145	-6.05%	$272,019	$0.08134	4.25%	$279,029	$.08344	6.93%	27
28	Standby			$131		$352	168.61%	$391		199.16%	$141		8.02%	28
29	TOTAL	13,526,676	$.06198	$1,249,085	$0.09234	$1,165,888	-6.66%	$1,293,698	$0.09564	3.57%	$1,326,903	$.09810	6.23%	29
	E-19 CLASS													
30	E-19 T	23,437	$.06443	$1,376	$0.05433	$2,751	39.17%	$3,052	$0.13023	54.43%	$2,305	$.09833	16.61%	30
31	E-19/25 P	363,356	$.05498	$28,981	$0.07979	$27,779	-4.18%	$30,824	$0.08483	6.32%	$31,778	$.08746	9.61%	31
32	E-19/25 S	3,560,065	$.06279	$313,638	$0.08810	$310,847	-0.89%	$344,923	$0.09689	9.97%	$355,556	$.09988	13.38%	32
35	A-RTP-19 S	41,243	$.05799	$2,764	$0.06750	$3,326	19.47%	$3,690	$0.08948	32.57%	$3,245	$.07871	16.61%	35
36	Standby			$366		$886	142.19%	$983		168.74%	$391		6.82%	36
37	TOTAL	3,968,101	$.06232	$347,755	$0.08722	$345,586	-0.62%	$383,473	$0.09615	10.27%	$393,315	$.09862	13.10%	37
	E-20 CLASS													
38	E-20 T	3,164,669	$.03791	$181,968	$0.05751	$170,340	-6.40%	$189,014	$0.05973	3.86%	$195,774	$.06186	7.58%	38
39	E-20 P	6,702,500	$.04321	$496,563	$0.07409	$463,132	-6.74%	$513,902	$0.07667	3.49%	$532,263	$.07942	7.19%	39
40	E-20 S	4,683,363	$.05617	$369,762	$0.07892	$365,981	-1.02%	$406,102	$0.08667	9.83%	$417,036	$.08901	12.79%	40
41	A-RTP-20 P	122,421	$.04352	$8,129	$0.06640	$8,430	3.71%	$9,354	$0.07641	15.08%	$9,168	$.07489	12.79%	41
42	A-RTP-20 S	122,421	$.05301	$8,357	$0.06827	$9,024	7.97%	$10,013	$0.08179	19.81%	$9,426	$.07700	12.79%	42
43	E-20 w/o Cntrcts, Stby	14,797,375	$.04398	$1,064,819	$0.07196	$1,016,907	-4.50%	$1,129,385	$0.07625	5.97%	$1,163,687	$.07864	9.29%	43
44	Contracts: T	520,136	$.03903	$27,752		$27,752		$27,752			$27,752			44
45	Contracts: P	1,313,273	$.04557	$78,926		$78,926		$78,926			$78,926			45
46	Contracts: S	20,832	$.05122	$1,371		$1,371		$1,371			$1,371			46
47	Standby			$2,072		$7,433	258.75%	$8,248		298.07%	$2,120		2.33%	47
48	TOTAL	16,651,736	$.04893	$1,174,939	$0.07056	$1,132,388	-3.62%	$1,244,681	$0.07475	5.94%	$1,273,856	$.07650	8.42%	48
49	SYSTEM TOTAL	69,294,836	$.06777	$6,533,028	$0.09428	$6,533,028	0.00%	$7,237,364	$0.10444	10.78%	$7,237,364	$.10444	10.78%	49
50	Check	69,294,836		$6,533,028	$0.09428	$6,533,028	0.00%	$7,237,364	$0.10444		$7,237,364		5/	50
51	TOTAL INCREASE							$704,336			$704,336			51

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, and (f) LIRA Revenues.
2/ Negotiated contract revenues are excluded from the allocation process and held constant at present levels.
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.

APPENDIX B
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PACIFIC GAS AND ELECTRIC COMPANY

Calculation of Low Income Ratepayer Assistance Surcharge

LIRA Program Costs

Line No.	Description:	Tier 1	Tier 2	Minimum Bill	Total
1	Proposed Residential rate before surcharge	0.10641	0.14106		
2	Percent Discount	15%	15%		
3	Low Income Discount ($/kWh) or ($/bill) (Line 1 * Line 2)	0.01596	0.02116	0.75	
4	LIRA Sales(kWh) or Bills	1,004,764,917	474,242,563	99,901	
5	Low Income Discount (Line 3 * Line 4)	$16,036,048	$10,034,973	$74,925	$26,145,946
6	1990 ECAC Forecast Period Administrative Budget with FF&U				$1,975,283
7	Forecast LIRA Account Balance on 10/31/90				($16,667,000)
8	Total LIRA Program Costs (Line 5 + Line 6 + Line 7)				$11,454,229

Sales Subject to LIRA Surcharge

Line No.	Description	Total
9	Total Forecast Sales (kWh) (Unadjusted for EE discount & includes CCSF power from Hetch Hetchy sales)	69,492,077,006
	Adjustments:	
10	EE Adjustment	65,093,066
11	Low-income forecast period sales (Line 4)	1,479,007,480
12	Street Light Sales (LS-1, LS-2, LS-3, TC-1)	381,899,000
13	Special Contract Sales	1,854,363,625
14	Total Adjustments (Line 10 + Line11 + Line 12 + Line 13)	3,780,363,171
15	Total kWh Sales Subject to LIRA Surcharge (Line 9 - Line 14)	65,711,713,835

Calculation of the LIRA Surcharge

Line No.	Description	Total
16	Total LIRA Program Costs ($) (Line 8)	$11,454,229
17	Total kWh Sales Subject to LIRA Surcharge (Line 15)	65,711,713,835
18	LIRA surcharge ($/kWh) [(Line 16/Line 17)]	0.00017

(END APPENDIX B)

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PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF ADOPTED MARGINAL COSTS

Marginal Energy Costs	Summer Peak (¢/kWh)	Summer Partial-Peak (¢/kWh)	Summer Off-Peak (¢/kWh)	Winter Partial-Peak (¢/kWh)	Winter Off-Peak (¢/kWh)	Annual (¢/kWh)
Generation	3.268	2.522	2.331	2.688	2.215	2.472
Transmission	3.697	2.919	2.724	3.090	2.601	2.868
Distribution						
Primary	3.870	3.030	2.803	3.226	2.672	2.965
Secondary	4.011	3.106	2.846	3.331	2.709	3.027

Marginal Capacity Costs	($/kW-yr)
Generation	$56.17
ERI (1991-1996)	0.471
ERI Adjusted	$26.46
Transmission	$31.80
Distribution	
Primary	$53.00
Secondary	$6.87

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

(END OF APPENDIX C)

APPENDIX D
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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED RESIDENTIAL RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$2.57	$2.57	$2.57	$2.57	2
3	ET UNIT DISCOUNT ($/UNIT/MONTH)	$10.26	$10.26	$10.26	$10.26	3
4	TIER 1 ENERGY ($/KWH)	$0.09374	$0.09374	$0.10658	$0.10658	4
5	TIER 2 ENERGY ($/KWH)	$0.12842	$0.12842	$0.14123	$0.14123	5
	SCHEDULE EL-1					
6	MINIMUM BILL ($/MONTH)	$4.25	$4.25	$4.25	$4.25	6
7	TIER 1 ENERGY ($/KWH)	$0.07924	$0.07924	$0.09045	$0.09045	7
8	TIER 2 ENERGY ($/KWH)	$0.10872	$0.10872	$0.11990	$0.11990	8
	SCHEDULES E-7 AND EL-7					
9	MINIMUM BILL ($/MONTH)	$5.00	$5.00	$5.00	$5.00	9
10	E-7 METER CHARGE ($/MONTH)	$4.40	$4.40	$4.40	$4.40	10
11	EL-7 METER CHARGE($/MONTH)	$0.00	$0.00	$0.00	$0.00	11
12	ON-PEAK ENERGY ($/KWH)	$0.27844	$0.10774	$0.29729	$0.11467	12
13	OFF-PEAK ENERGY ($/KWH)	$0.08743	$0.07525	$0.09298	$0.07992	13
14	BASELINE DISCOUNT ($/KWH)	$0.02506	$0.02506	$0.02537	$0.02537	14
	SCHEDULE E-8					
15	CUSTOMER CHARGE	$13.92	$13.92	$13.92	$13.92	15
16	ENERGY CHARGE	$0.13892	$0.06805	$0.13848	$0.06782	16
17	ET MINIMUM RATE LIMITER	$0.04542	$0.04542	$0.05317	$0.05317	17

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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED SMALL L&P RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.12150	$0.09986	$0.13984	$0.11493	3
	SCHEDULE A-6					
4	CUSTOMER CHARGE ($/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)	$0.27871		$0.27771		7
8	PART-PEAK ENERGY ($/KWH)	$0.13935	$0.07434	$0.13885	$0.07407	8
9	OFF-PEAK ENERGY ($/KWH)	$0.07247	$0.05575	$0.07221	$0.05555	9
	SCHEDULE A-15					
10	CUSTOMER CHARGE ($/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)	$0.12992	$0.11599	$0.16060	$0.14338	12
	SCHEDULE TC-1					
13	CUSTOMER CHARGE ($/MONTH)	$7.50	$7.50	$7.50	$7.50	13
14	ENERGY ($/KWH)	$0.09606	$0.09606	$0.10067	$0.10067	14

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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED MEDIUM L&P RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$3.30	$3.30	$3.60	$3.60	2
3	PRIMARY DISCOUNT ($/KW/MONTH)	$0.70	$0.70	$0.80	$0.80	3
4	TRANS. DISCOUNT ($/KW/MONTH)	$2.60	$2.60	$2.90	$2.90	4
5	ENERGY CHARGE($/KWH)	$0.09407	$0.07290	$0.09915	$0.07684	5
	SCHEDULES A-11 AND E-14					
6	CUSTOMER CHARGE ($/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)	$3.30	$3.30	$3.60	$3.60	8
9	PRIMARY DISCOUNT ($/KW MONTH)	$0.70	$0.70	$0.80	$0.80	9
10	TRANS. DISCOUNT ($/KW/MONTH)	$2.60	$2.60	$2.90	$2.90	10
11	ON-PEAK DEMAND CHARGE ($/KW MONTH)	$9.20		$10.00		11
12	ON-PEAK ENERGY ($/KWH)	$0.10344		$0.10959		12
13	PART-PEAK ENERGY ($/KWH)	$0.07904	$0.05941	$0.08374	$0.06294	13
14	OFF-PEAK ENERGY ($/KWH)	$0.05305	$0.05145	$0.05621	$0.05451	14
15	E-14 ON-PEAK ENERGY ($/KWH)	$0.12784		$0.13545		15

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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 FIRM RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 RATES WINTER	LINE NO.
	SCHEDULE E-19 T					
1	CUSTOMER CHARGE ($/MONTH)	$510.00	$510.00	$510.00	$510.00	1
2	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$0.70	$0.70	$0.70	$0.70	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.20		$7.80		3
4	ON-PEAK ENERGY ($/KWH)	$0.09102		$0.10914		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.06178	$0.05282	$0.07408	$0.06334	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04716	$0.04575	$0.05655	$0.05486	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.57455		$0.62907		7
	SCHEDULE E-19 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$250.00	$250.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.60	$2.60	$2.80	$2.80	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.80		$9.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.10195		$0.11170		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.06920	$0.05916	$0.07582	$0.06482	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05283	$0.05124	$0.05787	$0.05614	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.13330		$0.14595		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.78445		$0.85889		15
	SCHEDULE E-19 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.30	$3.30	$3.60	$3.60	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.40		$10.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.10839		$0.12386		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.07357	$0.06290	$0.08407	$0.07188	20
21	OFF-PEAK ENERGY ($/KWH)	$0.05616	$0.05448	$0.06418	$0.06226	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.13330		$0.14595		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.78906		$0.86394		23

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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-19 NONFIRM RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.70	$0.70	$0.70	$0.70	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$1.18		$2.06		5
6	ON-PEAK ENERGY ($/KWH)	$0.08862		$0.10674		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.06015	$0.05143	$0.07245	$0.06195	7
8	OFF-PEAK ENERGY ($/KWH)	$0.04592	$0.04454	$0.05531	$0.05365	8
9	UFR CREDIT ($/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)	$2.60	$2.60	$2.80	$2.80	14
15	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.09		$4.83		15
16	ON-PEAK ENERGY ($/KWH)	$0.09350		$0.10325		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.06347	$0.05426	$0.07009	$0.05992	17
18	OFF-PEAK ENERGY ($/KWH)	$0.04845	$0.04699	$0.05349	$0.05189	18
19	UFR CREDIT ($/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)	$3.30	$3.30	$3.60	$3.60	24
25	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.26		$4.08		25
26	ON-PEAK ENERGY ($/KWH)	$0.10678		$0.12225		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.07248	$0.06197	$0.08298	$0.07095	27
28	OFF-PEAK ENERGY ($/KWH)	$0.05533	$0.05367	$0.06335	$0.06145	28
29	UFR CREDIT ($/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 D

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 FIRM RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.70	$0.70	$0.70	$0.70	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.20		$7.80		3
4	ON-PEAK ENERGY ($/KWH)	$0.07797		$0.08461		4
5	PARTIAL-PEAK ENERGY ($/KWH)	$0.05363	$0.04620	$0.05743	$0.04910	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04125	$0.04002	$0.04384	$0.04253	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.57455		$0.62907		7
	SCHEDULE E-20 P FIRM					
8	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$220.00	$220.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.60	$2.60	$2.80	$2.80	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.80		$9.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.09726		$0.10335		11
12	PARTIAL-PEAK ENERGY ($/KWH)	$0.06601	$0.05644	$0.07015	$0.05998	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05033	$0.04888	$0.05355	$0.05195	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.11565		$0.12663		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.78445		$0.85889		15
	SCHEDULE E-20 S FIRM					
16	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.30	$3.30	$3.60	$3.60	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.40		$10.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.09877		$0.11193		19
20	PARTIAL-PEAK ENERGY ($/KWH)	$0.06704	$0.05732	$0.07598	$0.06496	20
21	OFF-PEAK ENERGY ($/KWH)	$0.05118	$0.04964	$0.05800	$0.05626	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.11565		$0.12663		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.78906		$0.86394		23

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED E-20 NONFIRM RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.70	$0.70	$0.70	$0.70	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$1.18		$3.01		5
6	ON-PEAK ENERGY ($/KWH)	$0.07592		$0.08256		6
7	PARTIAL-PEAK ENERGY ($/KWH)	$0.05222	$0.04499	$0.05602	$0.04789	7
8	OFF-PEAK ENERGY ($/KWH)	$0.04017	$0.03896	$0.04276	$0.04147	8
9	UFR CREDIT ($/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)	$2.60	$2.60	$2.80	$2.80	14
15	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.09		$6.43		15
16	ON-PEAK ENERGY ($/KWH)	$0.08990		$0.09599		16
17	PARTIAL-PEAK ENERGY ($/KWH)	$0.06102	$0.05217	$0.06516	$0.05571	17
18	OFF-PEAK ENERGY ($/KWH)	$0.04658	$0.04518	$0.04974	$0.04825	18
19	UFR CREDIT ($/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)	$3.30	$3.30	$3.60	$3.60	24
25	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.26		$5.28		25
26	ON-PEAK ENERGY ($/KWH)	$0.09365		$0.10701		26
27	PARTIAL-PEAK ENERGY ($/KWH)	$0.06370	$0.05446	$0.07264	$0.06210	27
28	OFF-PEAK ENERGY ($/KWH)	$0.04863	$0.04717	$0.05545	$0.05379	28
29	UFR CREDIT ($/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 D
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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED REAL TIME PRICING RATES

LINE NO.		7/8/90 RATES SUMMER 1/	7/8/90 RATES WINTER 1/	1/1/91 RATES SUMMER 2/	1/1/91 RATES WINTER 2/	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)	$190.00	$190.00	$190.00	$190.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.60	$2.60	$2.80	$2.80	3
4	BASE ENERGY RATE ($/KWH)	$0.00288	$0.00288	$0.00332	$0.00332	4
5	ON-PEAK ENERGY MULTIPLIER	3.0247		3.8598		5
6	PART-PEAK ENERGY MULTIPLIER	1.9466	1.9466	2.1990	2.1990	6
7	OFF-PEAK ENERGY MULTIPLIER	1.4792	1.4792	1.5780	1.5780	7
8	LOAD MANAGEMENT PRICE SIGNAL - TIER 1	$0.53		$0.53		8
9	LOAD MANAGEMENT PRICE SIGNAL - TIER 2	$0.40		$0.40		9
10	LOAD MANAGEMENT PRICE SIGNAL - TIER 3	$0.27		$0.27		10
	SCHEDULE A-RTP SECONDARY					
11	E-19 CUSTOMER CHARGE ($/MONTH)	$280.00	$280.00	$280.00	$280.00	11
12	E-20 CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$330.00	$330.00	12
13	OPTIONAL SERVICE CHARGE ($/MONTH)	$190.00	$190.00	$190.00	$190.00	13
14	MAXIMUM DEMAND CHARGE ($/KW MO.)	$3.30	$3.30	$3.60	$3.60	14
15	BASE ENERGY RATE ($/KWH)	$0.00288	$0.00288	$0.00332	$0.00332	15
16	ON-PEAK ENERGY MULTIPLIER	3.0247		3.8598		16
17	PART-PEAK ENERGY MULTIPLIER	1.9466	1.9466	2.1990	2.1990	17
18	OFF-PEAK ENERGY MULTIPLIER	1.4792	1.4792	1.5780	1.5780	18
19	LOAD MANAGEMENT PRICE SIGNAL - TIER 1	$0.53		$0.53		19
20	LOAD MANAGEMENT PRICE SIGNAL - TIER 2	$0.40		$0.40		20
21	LOAD MANAGEMENT PRICE SIGNAL - TIER 3	$0.27		$0.27		21

1/ Rates expire on 12/31/90.

2/ Subject to approval of Advice Letter 1324-E.

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED LARGE L&P RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.70	$0.70	$0.70	$0.70	2
3	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$7.20		$7.80		3
4	ON-PEAK ENERGY ($/KWH)	$0.09014		$0.12667		4
5	PART-PEAK ENERGY ($/KWH)	$0.05363	$0.04620	$0.07408	$0.06334	5
6	OFF-PEAK ENERGY ($/KWH)	$0.04125	$0.04002	$0.05655	$0.05486	6
7	ON-PEAK RATE LIMIT ($/KWH)	$0.57455		$0.62907		7
	SCHEDULE E-25P					
8	CUSTOMER CHARGE ($/MONTH)	$220.00	$220.00	$250.00	$250.00	8
9	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.60	$2.60	$2.80	$2.80	9
10	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$8.80		$9.50		10
11	ON-PEAK ENERGY ($/KWH)	$0.11288		$0.12964		11
12	PART-PEAK ENERGY ($/KWH)	$0.06601	$0.05644	$0.07582	$0.06482	12
13	OFF-PEAK ENERGY ($/KWH)	$0.05039	$0.04838	$0.05787	$0.05614	13
14	AVERAGE RATE LIMIT ($/KWH)	$0.13330		$0.12663		14
15	ON-PEAK RATE LIMIT ($/KWH)	$0.78445		$0.85889		15
	SCHEDULE E-25S					
16	CUSTOMER CHARGE ($/MONTH)	$330.00	$330.00	$280.00	$280.00	16
17	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$3.30	$3.30	$3.60	$3.60	17
18	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.40		$10.20		18
19	ON-PEAK ENERGY ($/KWH)	$0.11464		$0.14376		19
20	PART-PEAK ENERGY ($/KWH)	$0.06704	$0.05732	$0.08407	$0.07168	20
21	OFF-PEAK ENERGY ($/KWH)	$0.05118	$0.04964	$0.06418	$0.06226	21
22	AVERAGE RATE LIMIT ($/KWH)	$0.13330		$0.12663		22
23	ON-PEAK RATE LIMIT ($/KWH)	$0.78906		$0.86394		23

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED LARGE L&P RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$0.70	$0.70	$0.70	$0.70	3
4	ON-PEAK DEMAND CHARGE ($/KW MONTH)	$2.84		$4.33		4
5	ON-PEAK ENERGY ($/KWH)	$0.10446		$0.11360		5
6	PART-PEAK ENERGY ($/KWH)	$0.05261	$0.04532	$0.05641	$0.04823	6
7	OFF-PEAK ENERGY ($/KWH)	$0.04047	$0.03925	$0.04306	$0.04176	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)	$2.60	$2.60	$2.80	$2.80	11
12	ON-PEAK DEMAND CHARGE ($/KW MONTH)	$3.93		$7.27		12
13	ON-PEAK ENERGY ($/KWH)	$0.12145		$0.12968		13
14	PART-PEAK ENERGY ($/KWH)	$0.06239	$0.05335	$0.06659	$0.05694	14
15	OFF-PEAK ENERGY ($/KWH)	$0.04763	$0.04620	$0.05083	$0.04931	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)	$3.30	$3.30	$3.60	$3.60	19
20	ON-PEAK DEMAND CHARGE ($/KW MONTH)	$4.22		$6.63		20
21	ON-PEAK ENERGY ($/KWH)	$0.12579		$0.14339		21
22	PART-PEAK ENERGY ($/KWH)	$0.06463	$0.05525	$0.07366	$0.06297	22
23	OFF-PEAK ENERGY ($/KWH)	$0.04933	$0.04785	$0.05623	$0.05454	23
24	EXCESS DEMAND CHARGE / KWH	$6.27077	$6.27077	$6.27077	$6.27077	24

APPENDIX D
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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED STANDBY RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 RATES WINTER	LINE NO.
	SCHEDULE S - TRANSMISSION					
1	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$0.70	$0.70	$0.70	$0.70	1
2	ON-PEAK RATE LIMITER ($/KWH)	$0.57455		$0.62907		2
	SCHEDULE S - PRIMARY					
3	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$2.60	$2.60	$2.80	$2.80	3
4	ON-PEAK RATE LIMITER ($/KWH)	$0.78445		$0.85889		4
	SCHEDULE S - SECONDARY					
5	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$3.30	$3.30	$3.60	$3.60	5
6	ON-PEAK RATE LIMITER ($/KWH)	$0.78900		$0.86394		6
	REDUCED CUSTOMER CHARGE ($/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

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$1.80	$1.80	$2.10	$2.10	2
3	ENERGY CHARGE ($/KWH)	$0.11441	$0.11441	$0.13690	$0.13690	3
4	RATE LIMITER	$0.97337	$0.97337	$1.12804	$1.12804	4
	SCHEDULE AG-RA					
5	CUSTOMER CHARGE ($/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)	$1.80	$1.80	$2.10	$2.10	7
8	ON-PEAK ENERGY ($/KWH)	$0.27632		$0.32849		8
9	PART-PEAK ENERGY ($/KWH)		$0.05789		$0.06882	9
10	OFF-PEAK ENERGY ($/KWH)	$0.06444	$0.04604	$0.07661	$0.05473	10
11	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	11
	SCHEDULE AG-VA					
12	CUSTOMER CHARGE ($/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)	$1.80	$1.80	$2.10	$2.10	14
15	ON-PEAK ENERGY ($/KWH)	$0.27273		$0.32273		15
16	PART-PEAK ENERGY ($/KWH)		$0.05714		$0.06762	16
17	OFF-PEAK ENERGY ($/KWH)	$0.06219	$0.04544	$0.07359	$0.05377	17
18	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	18
	SCHEDULE AG-4A					
19	CUSTOMER CHARGE ($/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)	$1.80	$1.80	$2.10	$2.10	21
22	ON-PEAK ENERGY ($/KWH)	$0.26992		$0.32029		22
23	PART-PEAK ENERGY ($/KWH)		$0.05655		$0.06710	23
24	OFF-PEAK ENERGY ($/KWH)	$0.05429	$0.04497	$0.06442	$0.05336	24
25	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	25

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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)	$4.55	$4.55	$5.10	$5.10	3
4	ON-PEAK ENERGY ($/KWH)	$0.19119		$0.22772		4
5	PART-PEAK ENERGY ($/KWH)		$0.04006		$0.04771	5
6	OFF-PEAK ENERGY ($/KWH)	$0.03933	$0.03185	$0.04685	$0.03794	6
7	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	7
8	MINIMUM BILL ($/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)	$4.55	$4.55	$5.10	$5.10	10
11	ENERGY CHARGE ($/KWH)	$0.06700	$0.03486	$0.07973	$0.04170	11
12	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	12
	SCHEDULE AG-1B					
13	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	13
14	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.20	$1.50	$2.55	$1.75	14
15	ENERGY CHARGE ($/KWH)	$0.10161	$0.10161	$0.11883	$0.11883	15
16	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	16
	SCHEDULE AG-RB					
17	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	17
18	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	18
19	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.20	$1.50	$2.55	$1.75	19
20	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.20		$2.55		20
21	ON-PEAK ENERGY ($/KWH)	$0.24105		$0.28380		21
22	PART-PEAK ENERGY ($/KWH)		$0.06613		$0.07732	22
23	OFF-PEAK ENERGY ($/KWH)	$0.07139	$0.05259	$0.08347	$0.06149	23
24	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	24

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 RATES WINTER	LINE NO.
	SCHEDULE AG-VB					
1	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	1
2	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.20	$1.50	$2.55	$1.75	3
4	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.20		$2.55		4
5	ON-PEAK ENERGY ($/KWH)	$0.21405		$0.25229		5
6	PART-PEAK ENERGY ($/KWH)		$0.06413		$0.07501	6
7	OFF-PEAK ENERGY ($/KWH)	$0.06710	$0.05099	$0.07849	$0.05954	7
8	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	8
	SCHEDULE AG-4B					
9	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	9
10	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	10
11	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.20	$1.50	$2.55	$1.75	11
12	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.20		$2.55		12
13	ON-PEAK ENERGY ($/KWH)	$0.18083		$0.21011		13
14	PART-PEAK ENERGY ($/KWH)		$0.05920		$0.06917	14
15	OFF-PEAK ENERGY ($/KWH)	$0.05625	$0.04707	$0.06572	$0.05499	15
16	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	16
	SCHEDULE AG-4C					
17	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	17
18	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	18
19	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$2.20	$1.50	$2.55	$1.75	19
20	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.20		$2.55		20
21	ON-PEAK ENERGY ($/KWH)	$0.18083		$0.21011		21
22	PART-PEAK ENERGY ($/KWH)	$0.07679	$0.05920	$0.09451	$0.06917	22
23	OFF-PEAK ENERGY ($/KWH)	$0.04975	$0.04707	$0.06123	$0.05499	23
24	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	24

PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED AGRICULTURAL RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 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	$5.10	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$5.45	$3.65	$6.00	$4.05	3
4	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.25		$2.50		4
5	ON-PEAK ENERGY ($/KWH)	$0.12313		$0.13601		5
6	PART-PEAK ENERGY ($/KWH)		$0.03668		$0.04049	6
7	OFF-PEAK ENERGY ($/KWH)	$0.03539	$0.02917	$0.03907	$0.03220	7
8	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	8
9	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		9
	SCHEDULE AG-5C					
10	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	10
11	METER CHARGE ($/MONTH)	$5.10	$5.10	$5.10	$5.10	11
12	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$5.45	$3.65	$6.00	$4.05	12
13	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$2.25		$2.50		13
14	ON-PEAK ENERGY ($/KWH)	$0.12313		$0.13601		14
15	PART-PEAK ENERGY ($/KWH)	$0.04846	$0.03668	$0.05363	$0.04049	15
16	OFF-PEAK ENERGY ($/KWH)	$0.03082	$0.02917	$0.03411	$0.03220	16
17	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	17
18	MINIMUM BILL ($/KW/YEAR)	$0.00		$0.00		18
	SCHEDULE AG-6B					
19	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	$10.00	$10.00	19
20	MAXIMUM DEMAND CHARGE ($/KW/MONTH)	$5.45	$3.65	$6.00	$4.05	20
21	ENERGY CHARGE ($/KWH)	$0.05976	$0.03200	$0.06688	$0.03552	21
22	RATE LIMITER ($/KWH)	$0.97337	$0.97337	$1.12804	$1.12804	22

APPENDIX D
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PACIFIC GAS AND ELECTRIC COMPANY
CURRENT AND ADOPTED STREETLIGHTING RATES

LINE NO.		7/8/90 RATES SUMMER	7/8/90 RATES WINTER	1/1/91 RATES SUMMER	1/1/91 RATES WINTER	LINE NO.
	SCHEDULE LS-3					
1	SERVICE CHARGE ($/METER/MO.)	$3.00	$3.00	$3.00	$3.00	1
2	SWITCHING CHARGE ($/CIRCUIT)	$3.25	$3.25	$3.25	$3.25	2
3	ENERGY CHARGE ($/KWH)	$0.07396	$0.07396	$0.07616	$0.07616	3
	SCHEDULE LS-1					
4	ENERGY CHARGE ($/KWH)	$0.07396	$0.07396	$0.07616	$0.07616	4
	SCHEDULE LS-2					
5	ENERGY CHARGE ($/KWH)	$0.07396	$0.07396	$0.07616	$0.07616	5
	SCHEDULE OL-1					
6	ENERGY CHARGE ($/KWH)	$0.07396	$0.07396	$0.07633	$0.07633	6

PACIFIC GAS AND ELECTRIC COMPANY
RATES FOR SCHEDULES LS-1, LS-2 AND OL-1
FACILITY RATES EFFECTIVE 1-01-91
ENERGY RATES AT 90 ECAC DECISION ENERGY RATES

--NOMINAL LAMP RATINGS-- LAMP WATTS	KWHR PER MONTH	AVERAGE INITIAL LUMENS	ALL NIGHT RATES PER LAMP PER MONTH — SCHEDULE LS-2 A	B	C	SCHEDULE LS-1 A	B	C	D	D.1	E	E.1	F	F.1	OL-1	HALF-HOUR ADJ. (LS-2	(LS-1 & OL-1)
MERCURY VAPOR LAMPS																	
100	40	3,500	3.197	4.018	4.505	8.990	—	7.177	—	—	—	—	—	—	—	.138	—
175	68	7,500	5.330	6.112	6.532	10.706	8.214	9.284	—	—	13.663	13.663	17.477	15.345	10.718	.235	.236
250	97	11,000	7.539	8.377	8.847	13.726	10.776	—	—	—	—	—	—	—	—	.335	—
400	152	21,000	11.727	12.547	13.000	18.121	14.967	—	—	—	—	—	—	—	18.147	.526	.527
700	266	37,000	20.410	21.474	22.093	27.380	24.240	—	—	—	—	—	—	—	—	.921	—
1,000	377	57,000	28.863	29.871	30.424	—	—	—	—	—	—	—	—	—	—	1.345	—
INCANDESCENT LAMPS																	
58	20	600	—	—	—	10.115	—	—	—	—	—	—	—	—	—	.059	—
92	31	1,000	2.512	4.968	5.613	10.952	—	—	—	—	—	—	—	—	—	.107	—
189	65	2,500	5.101	7.614	8.387	13.743	12.966	—	—	—	—	—	—	—	—	.225	—
295	101	4,000	7.843	10.334	11.198	16.560	16.184	—	—	—	—	—	—	—	—	.359	—
405	139	6,000	10.737	13.441	14.158	19.557	—	—	—	—	—	—	—	—	—	.491	—
620	212	10,000	16.297	18.974	19.577	—	—	—	—	—	—	—	—	—	—	.734	—
860	294	15,000	22.542	25.454	—	—	—	—	—	—	—	—	—	—	—	1.018	—
LOW PRESSURE SODIUM VAPOR LAMPS																	
35	21	4,800	1.750	—	—	—	—	—	—	—	—	—	—	—	—	.073	—
55	29	8,000	2.360	—	—	—	—	—	—	—	—	—	—	—	—	.100	—
90	45	13,500	3.578	—	—	—	—	—	—	—	—	—	—	—	—	.156	—
135	62	21,500	4.873	—	—	—	—	—	—	—	—	—	—	—	—	.215	—
180	78	33,000	6.091	—	—	—	—	—	—	—	—	—	—	—	—	.270	—
HIGH PRESSURE SODIUM VAPOR LAMPS																	
AT 120 VOLTS																	
70	29	5,800	2.360	3.284	3.787	7.466	—	6.076	10.165	9.327	10.206	9.355	12.495	11.438	7.471	.100	.101
100	41	9,500	3.274	4.260	4.709	8.445	—	7.112	11.165	10.431	11.166	10.432	13.617	12.623	8.452	.142	.142
150	60	16,000	4.721	5.707	6.156	10.211	—	8.660	12.530	11.649	12.648	11.928	15.392	14.311	—	.208	—
AT 240 VOLTS																	
70	34	5,800	2.740	3.664	4.164	—	—	—	—	—	—	—	—	—	—	.118	—
100	47	9,500	3.731	4.716	5.187	—	—	—	—	—	—	—	—	—	—	.163	—
150	69	16,000	5.406	6.392	6.841	—	—	—	—	—	—	—	—	—	—	.239	—
200	81	22,000	6.320	7.316	7.889	13.038	—	10.995	—	—	14.914	14.511	18.936	17.292	13.952	.290	.291
250	100	27,000	7.767	8.763	9.336	14.914	—	12.512	—	—	16.659	16.122	20.813	19.437		.346	—
310	119	37,000	9.214	—	—	—	—	—	—	—	—	—	—	—		.412	—
400	154	46,000	11.800	12.866	13.448	19.992	—	16.862	—	—	21.070	20.947	25.625	24.009	—	.533	—
METAL HALIDE LAMPS																	
400	162	30,000	12.489	—	—	—	—	—	—	—	—	—	—	—	—	.561	—
1,000	387	90,000	29.625	—	—	—	—	—	—	—	—	—	—	—	—	1.340	—

Energy Rate @ .07616 per kwh LS-1 & LS-2
.07633 per kwh OL-1

12/17/1990

(End of Appendix D)